Review of potential regulatory models that could be applied in Hawaii

A working paper prepared by London Economics International LLC with support from Meister Consultants Group for the State of Hawaii

August 20, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. Five utility regulatory structures are reviewed in this memo based on the scope of work provided: (i) status quo; (ii) status quo with increased oversight; (iii) independent system operator; (iv) distribution-focused regulatory model; and (v) performance-based regulatory model. The Project Team also introduced a separate regulatory model for the Kauai Island Utility Cooperative ("KIUC") with lighter regulation than the status quo.

Table of Contents

London Economics International LLC
717 Atlantic Ave., Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Cherrylin Trinidad/Tianying Lan
617-933-7229
cherrylin@londoneconomics.com

Table of Figures

List of acronyms

AIFI	Average Interruption Frequency Index
CAIDI	Customer Average Interruption Duration Index
Capex	Capital expenditure
Co-op	Cooperative
COS	Cost of Service
CPUC	California Public Utilities Commission
DBEDT	Hawaii Department of Business Economic Development and Tourism
DERs	Distributed energy resources
DR	Demand response
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Provider
DUOS	Distribution use of system
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IDER	Integrated Distributed Energy Resources
IDSO	Independent distribution system operator
IOU	Investor-owned Utility
IPPs	Independent Power Producers
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
MPUC	Maine Public Utilities Commission
NERC	North American Electric Reliability Corporation
NY PSC	New York Public Service Commission
OASIS	Open Access Same time Information System
OEB	Ontario Energy Board
Opex	Operating expenditure
Ofgem	Office of Gas and Electricity Markets
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PUC	Public Utilities Commission
RAM	Revenue Adjustment Mechanism
REV	Reforming the Energy Vision

RIIO	Revenue = Incentives + Innovation + Outputs
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
RUS	Rural Utilities Services
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TFP	Total factor productivity
TIS	Texas Interconnected System
Totex	Total expenditure
UK	United Kingdom

Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The State of Hawaii is gearing up for the strengthening of its energy sector, targeting, among others, 100 percent renewable energy in its electricity sector by 2045. This working paper, which responds to Task 2.1.1 in the project scope of work, provides an overview of the various types of regulatory models and evaluates their features. We have also considered the high-level steps that would be necessary if other regulatory structures were to be implemented. A more detailed assessment of each regulatory model's technical, financial, and legal feasibility and steps will be discussed in the succeeding tasks.[1]

Based on the Project Team's preliminary work interaction with the stakeholders, a regulatory model should be able to achieve the State's energy goals and provide a level playing field to all market players. Moreover, the regulatory model should encourage the deployment of distributed energy resources and be able to support and take into consideration the underserved population of the State.

Five utility regulatory structures were reviewed based on the scope of work provided and our evaluation of various additional potential arrangements. These include: (i) status quo; (ii) status quo with increased oversight; (iii) independent system operator ("ISO"); (iv) distribution-focused regulatory model; and (v) performance-based regulation ("PBR") model. PBR comprises various mechanisms and could be used in different combinations. Therefore, for Hawaii, we have identified three (3) potential PBR options: (i) Light PBR; (ii) Conventional PBR; and (iii) Outcomes-based PBR.

- Light PBR would build upon the existing regulatory model and expand the current performance incentive mechanisms ("PIMs") to include other metrics that would enable the State to achieve its energy goals. The PIMs would also be symmetrical where utilities would both be rewarded and penalized for achieving and missing the agreed targets, respectively. Light PBR would use the same 3-year general rate cycle and also include the current earnings sharing mechanism ("ESM") where above threshold earnings would be shared with the customers.

- Conventional PBR would use a revenue cap. Rates would increase by an indexing formula based on an inflation and productivity factor during the 3-year regulatory period. This option would have the same expanded list of PIMs under Light PBR and continue to include the ESM. However, unlike the previous option, the ESM would be symmetrical and have a larger sharing percentage and deadband.

- Outcomes-based PBR, which is inspired from the United Kingdom's ("UK's") Revenue = Incentives + Innovation + Outputs ("RIIO") model, would focus on setting the outcomes

[1] See Section 1.3 for the list and description of Tasks related to this memo.

and providing the utilities the flexibility on how to achieve the results and what inputs to use to deliver them. The regulatory term under this option would be longer (at 5 years) to strengthen efficiency incentives and help manage the pace of rate increases for customers. This option would require more stringent monitoring and reporting requirements compared with the other two PBR options.

Figure 1. Public Utilities Commission's ("PUC") roles under each regulatory model

<table>
<tr><th></th><th>Oversight responsibilities</th><th>Status quo</th><th>Status quo with increased oversight</th><th>ISO</th><th>Distribution -focused regulation</th><th>PBR</th></tr>
<tr><td rowspan="5">Generation</td><td>Monitors availability (generation)</td><td rowspan="3">PUC</td><td>HERA</td><td>ISO</td><td rowspan="5">PUC</td><td rowspan="5">PUC</td></tr>
<tr><td>Approves fuel supply contracts</td><td rowspan="2">PUC</td><td>N/A</td></tr>
<tr><td>Approves PPAs and new generation builds</td><td>ISO</td></tr>
<tr><td>Determines resource needs</td><td>Utility</td><td>Utility and HERA</td><td>ISO</td></tr>
<tr><td>Approves resource planning</td><td>PUC</td><td>PUC</td><td>PUC</td></tr>
<tr><td rowspan="4">Transmission</td><td>Monitors reliability (transmission)</td><td rowspan="2">PUC</td><td>HERA</td><td>ISO</td><td rowspan="2">PUC</td><td rowspan="2">PUC</td></tr>
<tr><td>Ensures grid access (transmission)</td><td>HERA</td><td>ISO</td></tr>
<tr><td>Determines transmission investment needs</td><td>Utility</td><td>Utility</td><td>ISO</td><td>Utility</td><td>Utility</td></tr>
<tr><td>Approves transmission investment needs</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td></tr>
<tr><td rowspan="6">Distribution</td><td>Monitors reliability (distribution)</td><td rowspan="2">PUC</td><td>HERA</td><td>ISO</td><td>DSO</td><td rowspan="2">PUC</td></tr>
<tr><td>Ensures grid access (distribution)</td><td>HERA</td><td>PUC</td><td>DSO</td></tr>
<tr><td>Monitors availability (DER on distribution)</td><td>Utility</td><td>Utility</td><td>Utility</td><td>DSPP/DSO</td><td>Utility</td></tr>
<tr><td>Monitors service quality</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td></tr>
<tr><td>Determines distribution investment needs</td><td>Utility</td><td>Utility</td><td>Utility</td><td>DSPP/DSO</td><td>Utility</td></tr>
<tr><td>Approves distribution investments needs</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td><td>PUC</td></tr>
<tr><td rowspan="3">Cross cutting</td><td>Regulates rates</td><td rowspan="3">PUC</td><td rowspan="3">PUC</td><td>PUC (T&D)</td><td rowspan="3">PUC</td><td rowspan="3">PUC</td></tr>
<tr><td>Approves financial transactions (e.g., issuance of stocks etc.)</td><td rowspan="2">PUC</td></tr>
<tr><td>Approves large capital investments</td></tr>
</table>

Note:
ISO – Independent System Operator; PBR – Performance-based Regulation; HERA – Hawaii Electricity Reliability Administrator; DSPP – Distribution System Platform Provider; DSO – Distribution System Operator; G – Generation; T&D – Transmission, and distribution; PPA- Power Purchase Agreements

Role of PUC under the three variants of PBR are the same.

contact:
Cherrylin Trinidad/Tianying Lan
617-933-7229
cherrylin@londoneconomics.com

Finally, the Project Team also considered a lighter regulation model for Kauai Island Utility Cooperative ("KIUC"). Given the difference in business models for KIUC compared with other Hawaii utilities, this is a potentially viable regulatory framework that will be explored further in future deliverables.

Some of these regulatory models (such as the status quo with increased oversight, ISO, and distribution-focused regulatory model) require delegating some of the current responsibilities of the Public Utilities Commission ("PUC") to an independent entity while others such as the PBR would require additional oversight from the PUC. Moreover, some of these regulatory models would entail certain changes in the responsibilities of the incumbent utilities and in the electricity sector value chain. For instance, under the ISO and distributed-focused regulatory model, an independent entity would oversee the day-to-day operations of the grid although the utilities would still own the network assets. Figure 1 shows a summary matrix of the PUC's oversight responsibilities under each regulatory model.

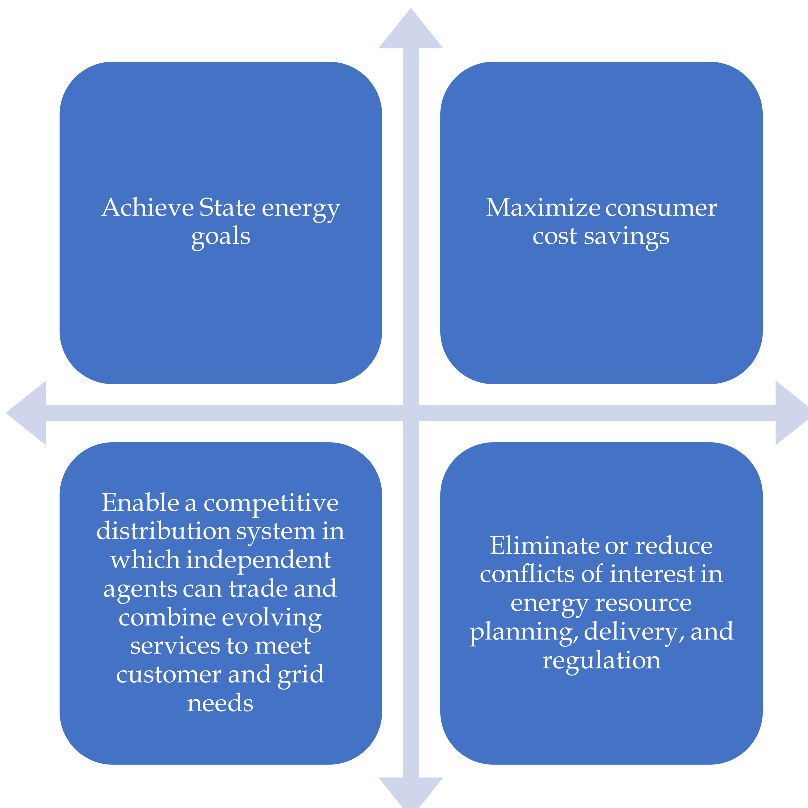
1 Introduction and Scope

1.1 Project description

DBEDT was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

The project aims to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[4] (Figure 2).

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595.

---

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. Moreover, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

1.2 Relevance of this deliverable relative to others in the project

This deliverable is responsive to Task 2.1.1 in the project scope of work. It introduces the various types of regulatory models and evaluates their characteristics. Also, multiple aspects of the regulatory models themselves will be further explored in subsequent deliverables. These deliverables include:

- assessment of current markets under each regulatory model, including a case study, analysis, and conclusions (Task 2.2.2);
- assessment (high-level) of the technical, financial, and legal feasibility of each regulatory model (Task 2.2.3);
- estimation of the stranded costs for each regulatory model (Task 2.2.4);
- solicitation of public input from each island currently served by an electric utility on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5);
- identification and recommendation for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each recommended model impacts State agencies staffing and stakeholders (Task 2.3.4);
- estimation of potential for each model to increase distributed energy resources (Task 2.4.1); and

[5] Hawaii Contract No. 65595. Scope of Services.

- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms for each regulatory model (Task 2.5).

1.3 Future refinements

As noted earlier, this deliverable is an overview of the different regulatory models and, as such, the results of our analysis are subject to further refinement and change as the project moves forward and additional information becomes available (namely, inputs from the stakeholder groups and results of the quantitative analysis and case studies). LEI will provide case studies in some of the deliverables (if applicable) to highlight the essential features of the different regulatory models and critical issues and lessons from other jurisdictions or utilities. Furthermore, the project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[6]

[6] A series of community meetings across the State was held in June 2018 in Hawaii. The workshops provided opportunities for the attendees, as well as online participants, to hear from key stakeholders in the energy policy discussion and provide inputs to the study through the small group discussions.

2 Key priorities of a regulatory model

The key priorities of a regulatory model will balance two aspects: (1) commonly accepted principles and (2) views of stakeholders.

2.1 Commonly accepted principles

As shown in Figure 3, there are five widely accepted principles in establishing a general regulatory regime and in setting rates/tariffs:[7]

- ***Incentives compatibility***: Ratemaking should provide appropriate incentives to both companies and customers (although some natural conflict may occur, and tradeoffs may be needed). According to the renowned economist Alfred E. Kahn, "*the central institutional questions related to suitable regulatory regimes have to do with the nature and adequacy of the incentives.*" [8] Incentive compatibility involves providing a suitable framework to encourage utilities to reduce costs while ensuring reliable, safe, and quality service for customers. Moreover, a sound regime should discourage inefficient consumption on the part of customers. An incentives-compatible scheme is one in which the interests of the regulated company (and its shareholders and management) and ratepayers are mostly aligned.

- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and generating enough cash flow to support necessary investment.

- ***Administrative simplicity and transparency***: Rates should be straightforward enough for customers to understand; customers should be able to calculate their monthly bills themselves and to know why the rate is calculated in the prescribed fashion. Complex ratemaking approaches increase costs to consumers. For example, an increase in accounting and billing costs (caused by complex ratemaking approaches) may result in more time being spent proving that the rates are indeed fair. As a result of this factor, ratemaking mechanisms should also be appropriate for the jurisdiction to which they are applied; complex rates in regions with inadequate data and understaffed regulators may be impossible to administer. However, it is worth noting that high levels of DER penetration are likely to make equitable cost allocation more complex and expensive even

---

[7] For more information, see: Bonbright, Danielson and Kamerschen. *Principles of Public Utility Rates*, Public Utility Reports Inc, Arlington, VA. 1988; Bonbright, Danielson. *Principles of Public Utility Rates*, Public Utility Reports Inc, Arlington. 1961. Page 290-94); Weston, Fredrick. "Principles of Rate Design." 1999. www.raponline.org); and Woolf, Tim and Julie Michals. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8.8 (October 1995).

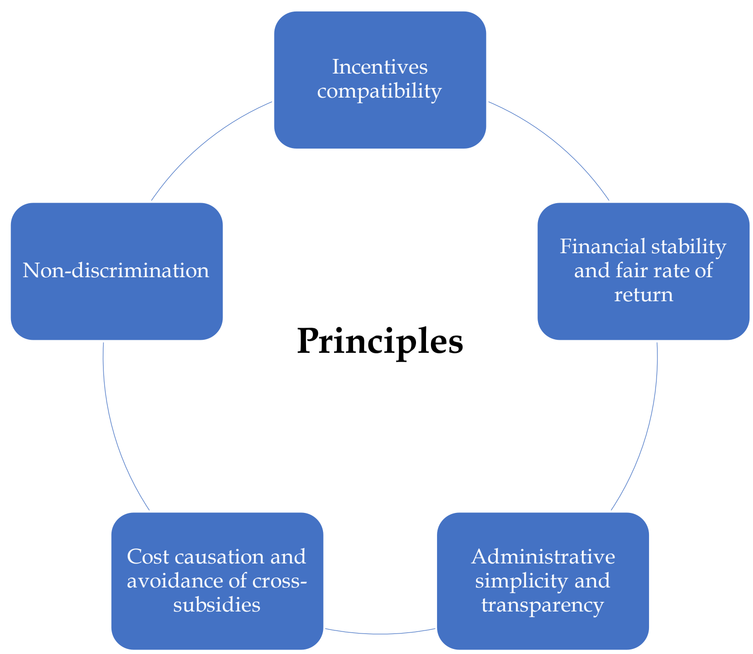
[8] Kahn, A.E. *The Economics of Regulation: Principles and Institutions*. Volume 1 (1970) and Volume 2 (1971). Wiley: New York (1970, 1971).

under the status quo. Sophisticated rates could potentially both include more effective price signals and reflect the appropriate costs in a future grid.

- ***Cost causation and avoidance of cross-subsidies***: In order to achieve the most efficient patterns of consumptions, economic theory states that the customers that cause a cost to be incurred should pay that cost. When cost causation is identified, then cross-subsidies (either between or within customer classes) can be avoided, re-aligning customers' incentives regarding consumption and their willingness to pay. Policy requirements may sometimes override this objective; however, in such cases, it must then be recognized that there will be some loss of efficiency. In addition, providing services to the grid by prosumers will need to be balanced with more simplified rates.

- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions. It is true that in a competitive marketplace, customers have the opportunity to change suppliers if better terms are available, while customers of a monopolistic utility do not have this alternative. However, in theory, competition will ensure that customers with similar tastes and preferences face a same set of choices, while in a regulated environment, such an outcome is assured only through enforcing non-discrimination in ratemaking. As customers have more choices in terms of the services they receive from the grid or provide to it, ratemaking must evolve to reflect the economic decision faced by customers.

Figure 3. Five commonly accepted principles



When deciding upon a regulatory regime or a change in regime, the above principles need to be assessed collectively. PBR regimes, as will be discussed in Section 3.5, could encourage utilities to reduce costs, but need to include mechanisms that would ensure a reliable, safe, and appropriate level of quality of service for customers. Any regulatory regime must offer an opportunity for a reasonably efficient utility to earn its commercially reasonable rate of return. PBR provides an opportunity for utilities that are more efficient or meet specific policy goal effectively to be rewarded in the form of higher returns. However, the targets set for efficiency need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. PBR also provides a mechanism for customers to benefit – through the constant, implicit "sharing" of efficiency gains via the formula, as well as through any other incremental earnings-sharing mechanism. However, an earnings-sharing mechanism that captures efficiency gains for customers would dull incentives for the utility. Therefore, as mentioned previously, a careful balancing of considerations is required.

2.2 According to the stakeholders

Based on the inputs from DBEDT and other stakeholders, the key priorities in a regulatory model include helping to achieve the State's energy goals, ensuring that utilities prudently recover their incurred costs, providing certainty by setting a timeline for its decision-making (among others), and respecting county-level differences. These inputs came from the Project Team's one-on-one meetings with stakeholders, workshops from the Verge Conference, and stakeholder outreach meetings conducted in October 2017. The Project Team had additional stakeholder outreach in June 2018. The discussion in this section will be explored further in Task 2.2.5 (Stakeholder Outreach Report).

DBEDT noted that a regulatory model should help to achieve the Energy Policy Directives, including:[9]

1. diversifying its energy portfolio;
2. connecting and modernizing its grids;
3. balancing technical, economic, environmental, and cultural considerations;
4. leveraging its position as an innovation test bed; and
5. promoting an efficient marketplace that benefits producers and consumers.

Particularly, DBEDT emphasized that the regulatory model needs to be able to capture various considerations in the third point of the Energy Policy Directives, which is to balance technical, economic, environmental, and cultural factors, beyond a least "economic" cost approach. Moreover, the regulatory model should address barriers to entry for new suppliers and provide opportunities for new types of technology and services (e.g., micro-grids, virtual power plants) to enter the market. The regulatory model needs to enable the full transition of the existing

---

[9] HESO. *Energy Policy: State of Hawaii Energy Policy Directives*. Website. <http://energy.hawaii.gov/energypolicy>

marketplace to a new more efficient marketplace and not just the incremental benefit-cost ratio of an individual step.[10]

Discussions in the Verge Conference session, one-on-one meetings, community outreach (June 2018), and email exchanges revealed that other stakeholders had the following concerns of individual stakeholders[11] on the existing regulatory model:

- current rate recovery model creates incentives for the utility that do not align with customer priorities;
- pricing signals should be fixed, and there should be a way to allow project developers to recover costs;
- some of the current regulations are outdated and do not sufficiently encourage business growth and utility innovation;
- slow regulatory procedures and process; and
- there is a need to reduce unnecessary regulation by the PUC on KIUC.

Therefore, stakeholders want to see the policies and regulations that: [12]

- are consistent and efficient;
- take the most vulnerable or underserved population into account;
- provide greater mechanisms and incentives to develop and innovate the industry;
- allow for more utility innovation and quicker adoption of new technologies;
- enable more renewables to be brought on the grid;
- align interests between community priorities and utility incentives;
- provide an independent entity or authority managing reliability or interconnection issues;

---

[10] DEBDT's reply to LEI's question. Schwing, Michael D. RE: Key priorities of a regulatory model. Sent: Monday, February 26, 2018 1:48 PM.

[11] These are comments from different stakeholders, but not necessarily consensus points.

[12] Summarized based on stakeholders' comments on regulatory models in the stakeholders' engagement process, including kick-off meeting in May 2017, VERGE Hawaii conference in June 2017, and community meetings in October 2017.

- foster infrastructure development to facilitate the broader use of distributed energy resources; and
- adapt to a rapidly changing energy landscape.

The regulatory models that the Project Team will review under Task 2 will hopefully address these concerns and discuss the priorities flagged by DBEDT and stakeholders.

3 Other potential regulatory models

A regulatory framework refers to the rule-making activity of the State or its regulatory agencies. Government entities involved in the regulatory process include a range of institutions such as those tasked with policy-making responsibilities by the executive branch (such as ministries or departments), creating and enforcing rules for implementation (such as regulatory bodies), and other government agencies responsible for different but related tasks.

In addition to the status quo, seven regulatory models are explored under Task 2 and briefly discussed in this paper. These are:

1. Status quo with increased oversight (or with the Hawaii Electricity Reliability Administrator ("HERA"));
2. ISO;
3. Distribution-focused regulatory model; and
4. Light PBR;
5. Conventional PBR;
6. Outcomes-based PBR; and
7. Lighter regulation for KIUC.

In some of these models, the oversight roles of the PUC would be reduced while it would have more responsibilities in others. For example, under the status quo with increased oversight, the grid access and reliability responsibilities would be executed by another entity instead of the PUC. On the other hand, under the PBR model, the PUC would have additional responsibilities, which include identifying and determining performance metrics and rewards/penalties that would be implemented, reviewing and ensuring that the forecasted revenue requirements are appropriate, and monitoring and evaluating the performance of the utilities.

In many cases, it is likely that additional resources are needed to implement these potential regulatory models. For instance, under the DSPP model, investments in new technologies are required to establish the DSPP and set up the required platforms.[13] Likewise, more comprehensive mechanisms of PBR (see Section 3.5.1 for a discussion on this) require collecting and employing multi-period information and data samples covering multiple companies. The availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools could improve the functionality of the PBR process. Outside support (e.g., from industry experts and consultants)) is common in other jurisdictions that have implemented PBR. This could assist the regulator in reviewing and confirming the

---

[13] See Task 1.1.4 (Assessment of Future Needs for Generation, Transmission, and Distribution Infrastructure in Each County) for a more detailed discussion on infrastructure needs under a distribution-focused model.

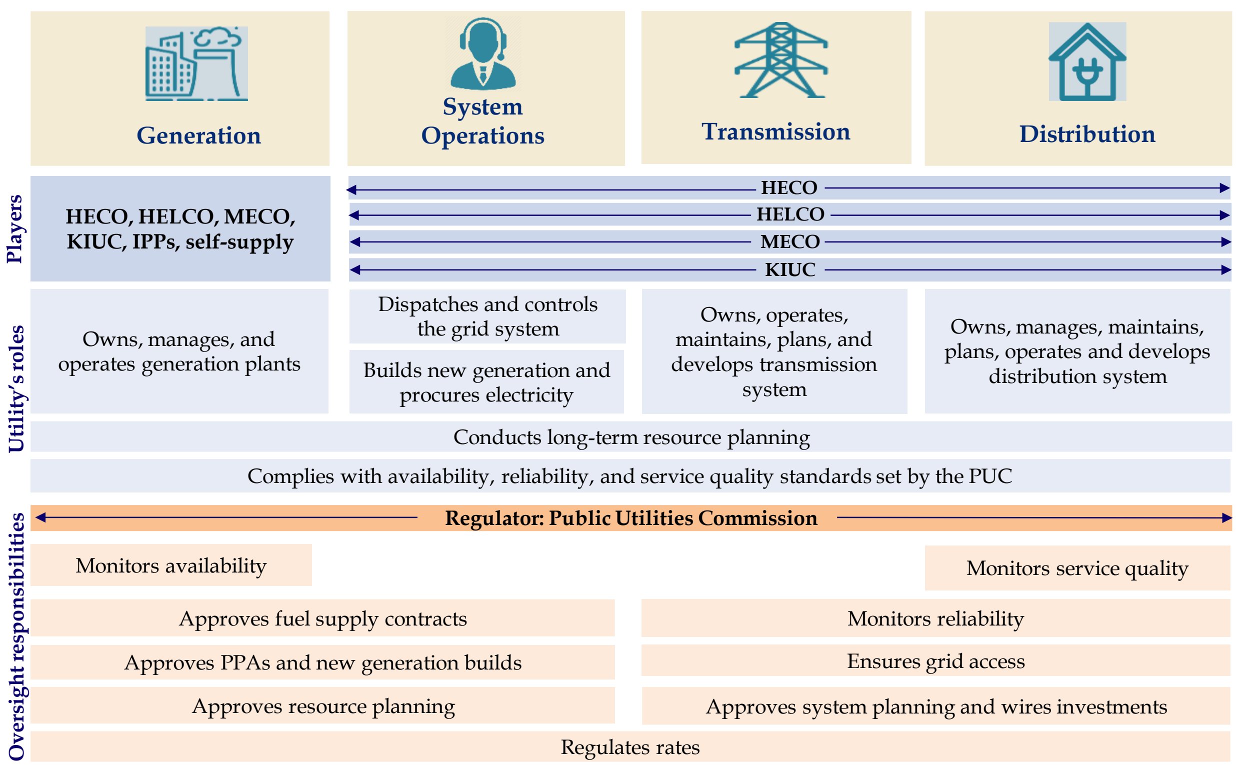
appropriateness of the PBR plan filed by the utilities. A more thorough discussion of the advantages and disadvantages of the different models will be discussed in Task 2.2.1.

3.1 Overview of the regulatory structure in Hawaii

The State of Hawaii is served by vertically integrated utilities, namely the Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Ltd. ("MECO"), Hawaiian Electric Company, Inc. ("HECO") (combined, these three subsidiaries will be called "HECO Companies" in this memo), and KIUC. The HECO Companies own most of the generation, transmission, and distribution assets in the counties that they serve. The Hawaii Electric Industries subsidiaries, including HECO, MECO, and HELCO, are investor-owned utilities ("IOU") that supply power to approximately 95% of Hawaii's population. On the other hand, KIUC is the only cooperative ("co-op") in the State.

There are three main institutional entities in the Hawaii electricity market – the State Legislature, PUC, and the Hawaii State Energy Office ("HSEO"). The HECO Companies and KIUC are regulated by the PUC.

Figure 4. Graphical depiction of the electric structure and oversight in the status quo model



The PUC is the regulatory body that regulates the electric utilities in Hawaii. It is enforced to regulate utilities' rates and ratemaking procedures, approve mergers and acquisitions of utilities, authorize construction of transmission lines, monitor electric reliability, and assess conditions of each utility regarding how it operates and its issuance of stocks, bonds and disposition of proceeds.[14] The PUC's current roles and responsibilities will be discussed in detail in Task 2.1.2 (Existing Regulatory Model in Hawaii). On the other hand, HSEO which is under DBEDT advises the State government which sets the energy policies. Figure 4 illustrates the current electric structure and oversight in the State.

Currently, electricity rates in the state are determined through a cost of service ("COS") approach that includes some components associated with PBR, namely: multi-year rate plan, ESMs between the utility and the customers for the HECO Companies, revenue cap, and decoupling. Task 2.1.2 (Existing Regulatory Model in Hawaii) will have a more detailed discussion on the current ratemaking process. Recently, the Governor of Hawaii signed the Ratepayer Protection Act (Senate Bill 2939) into law. It directed the PUC to investigate performance incentives and penalty mechanisms. Section 3.5.3 will provide a brief overview of this.

3.2 Status quo with increased oversight

Under the status quo with increased oversight model, the HERA is assumed to be implemented. The HERA was enabled by the Hawaii State legislation (Act 166) in 2012. HERA was envisioned to ensure that the State's clean energy goals would be achieved by implementing reliability standards across the electric value chain and providing fair grid access to generators:

> *"The legislature finds that the capability and accessibility of Hawaii's electrical system must be aligned with both the State's ambitious renewable portfolio standard mandate and the various technologies that generate electricity at both the distribution and transmission levels. ... However, in order to ensure that these types of generation resources can be integrated into the island grids, the technical, operational, and regulatory issues associated with running the electrical system must be considered and addressed in order to achieve the full potential of local renewable energy production. The implementation of formal reliability standards to govern all segments of the electric power system and to ensure fair and transparent grid access is a critical part of achieving Hawaii's lofty, clean energy requirements. Also, clear regulatory oversight of the State's grids will ensure system reliability, resiliency, and accountability."*[15]

The Hawaii PUC was authorized to enforce reliability standards and oversee grid access and interconnection issues and contract these functions out. [16] The PUC may contract with a person, business, or organization (except for a public utility) for the performance of HERA's functions.[17]

HRS 269-146 ordered that the Hawaii electricity reliability surcharge shall be collected to support the operations of HERA if needed. The Hawaii electricity reliability surcharge shall be collected from "*all utilities, persons, businesses, or entities connecting to the Hawaii electric system, or any other*

---

[14] For details, please refer to Hawaii Revised Statues ("HRS") Chapter 269 – Public Utilities Commission.

[15] Hawaii Senate Bill 2787. 2012. Website. <https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm>

[16] Hawaii House Bill 2525. 2012.

[17] HRS 269-147.

user, owner, or operator of any electric element that is a part of interconnection on the Hawaii electric system."[18] Moreover, the Hawaii PUC may allow *"an electric utility to recover appropriate and reasonable costs under the Hawaii electricity reliability surcharge for any interconnection to the Hawaii electric system, including interconnection studies and other analysis associated with studying the impact or necessary infrastructure and operational requirements needed to reliably interconnect a generator, as well as from electric utility customers through a surcharge or assessment subject to review and approval by the commission."*[19]

The law prescribes that HERA should report to the Hawaii PUC each year on the status of its operations, financial position, and a projected operating budget for the following fiscal year.[20] The law also requires that staff members should have "*appropriate skills and expertise to offer prudent and reasonable recommendations on the development of reliability standards and interconnection requirements*."

Moreover, HRS 269-148 emphasized that staff members should have the appropriate level of independence and the ability to fairly and impartially review matters concerning interconnection.[21]

Currently, there is no HERA in place in the State. However, a study on the structure of HERA has already been commissioned by the Mayor's Office of Economic Development of Maui County. The Study,[22] which was published on August 25, 2017, assessed the initial structure for HERA. According to the Study, the State might benefit from independent planning organizations that could provide pre-emptive reliability standards to accommodate Hawaii's Renewable Portfolio Standards ("RPS"), and such a function could be overseen by a HERA-type organization. It also stated that a HERA could give similar oversight for the interconnection application processes and timelines. However, the Study concluded that it is difficult to demonstrate that the costs that would be incurred to establish a separate entity would be covered by savings from changes in interconnection or reliability.

With such a challenge, an alternative is a "light" HERA, which could be designed as an ombudsman, an appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs convened when a customer wants to challenge utility interconnection behavior or lack of hosting capacity transparency. HERA would only investigate if the customer has exhausted utility internal appeals processes. HERA also drafts orders for the PUC to sign in

---

[18] HRS 269-146.

[19] Ibid.

[20] HRS 269-149.

[21] Ibid.

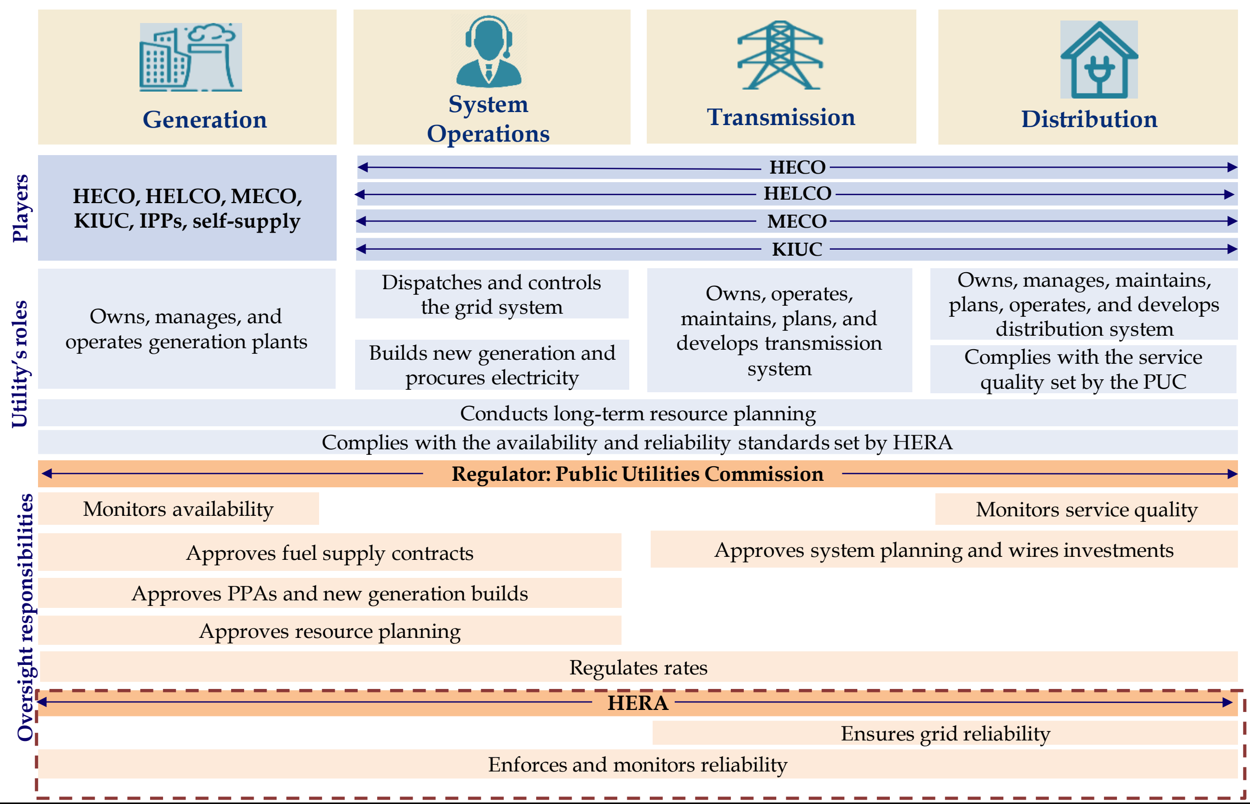
[22] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017.

the event that it finds utility behaving arbitrarily. However, the intent is that referral to HERA would serve as an incentive for utility and customer to settle differences.

3.2.1 Oversight under a HERA model

The increased oversight from HERA would not change the current structure of the electric value chain. Utilities would continue to operate the transmission and distribution network under this regulatory model. The PUC's role on grid access and reliability would be transferred to HERA as shown in Figure 5.

Figure 5. Graphical depiction of the value chain under a HERA model



3.2.2 Jurisdictions with a HERA model

HERA does not currently exist in Hawaii, but it is a concept that the Act 166, Session Laws of Hawaii 2012, authorized the PUC to develop, adopt, and be tasked to enforce reliability standards and interconnection requirements. A comparable entity is the North American Electric Reliability Corporation ("NERC") which is the electric reliability organization for North America, responsible for developing and enforcing mandatory electric reliability standards as overseen by the Federal Energy Regulatory Commission ("FERC"). NERC oversees both traditionally regulated and liberalized power markets. NERC was formed as a voluntary multi-utility response to the Northeast blackout of 1965. Forty years later, following the 2003 blackout, a US-Canadian Power System Outage Task Force was convened and made "recommendations regarding measures to reduce the risk of future power outages and the scope of any that do occur."[23] The transition to mandatory reliability standards then became necessary.

HERA and NERC have some similar features. First, both are a not-for-profit regulatory authority. Second, they have the same mission of ensuring the reliability and security of the grid. Third, both are directed to develop and enforce reliability standards. Lastly, HERA and NERC are subject to the oversight of the Commission (e.g., PUC for HERA and FERC for NERC).

3.3 Independent system operator

An independent system operator ("ISO") or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[24] The concept of an ISO grew out of Orders Nos. 888/889 and subsequently the concept of RTO was introduced in Order No. 2000 from the FERC. More specifically, the creation of new institutions such as RTOs/ISOs was part of the restructuring process to address reliability through coordinated transmission planning while also facilitating open access. FERC, via Order 2000,[25] encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America. In the same Order, FERC noted:

> "*Regional institutions can address the operational and reliability issues now confronting the industry, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation*."[26]

An ISO structure typically aims to assure reliability, which requires collaboration on the part of ISO, transmission owners and electricity utilities. This is ensured through the coordination of existing system components and processes to guarantee delivery of electricity upon demand, cooperation in monitoring and coordinating generation and transmission, communications and information sharing among all system operators to identify and isolate problems as they occur, and commitment by all electric utilities to continuously coordinate, cooperate, and communicate to protect and ensure system balance.

---

[23] Dawson, Kelly and Levi McAlister. "Restoring Faith in the Bulk-Power System: An early Assessment of Mandatory Reliability Standards." *The Electricity Journal* 23.2 (March 2010): Page 19-20.

[24] EIA. *Today in Energy*. Website. Access Date: March 22, 2018. <https://www.eia.gov/todayinenergy/detail.php?id=790>.

[25] FERC. *Order No. 2000 - Regional Transmission Organizations*. Docket No. RM99-2-000. December 20, 1999.

[26] United States of America 90 Ferc ¶ 61,201 Federal Energy., Website. Access Date: August 07, 2018. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/2000A.pdf>

In order to maintain reliability, certain responsibilities are performed by the ISO, while others remain with transmission owners and, as such, it may be essential to identify appropriate ISO functions and transmission owner functions respectively. ISO functions may include operational control of the transmission system, security coordinator for the region, administration of the ISO tariff, operation of the Open Access Same time Information System ("OASIS"),[27] allocation of available transfer capability, provision or coordination of ancillary services, involvement in transmission planning, implementation of congestion management procedures, coordination of transmission and generation, and maintenance scheduling.[28] On the other hand, transmission owners are responsible for owning, operating, and maintaining transmission facilities, conducting power system analysis and transmission planning studies, and constructing new transmission facilities.

In Hawaii, under this model, the utilities would still own and ratebase their transmission assets and pass the day-to-day coordination of flows of the transmission system to the ISO. In line with the minimum characteristics of an RTO as described in Order No. 2000, the potential ISO in Hawaii would have:

- independence;
- scope and regional configuration;
- operational authority; and
- responsibility for short-term reliability.[29]

In general, the governance structure of an ISO in other jurisdictions is two-tiered—the ISO Board and the Members Committee. The highest governing body is generally the Board of Managers, who have no affiliation with or financial stake in any ISO market participant. The number of board members varies across ISOs. For instance, in California ISO, there are five governors on its Board[30] while the Electric Reliability Council of Texas ("ERCOT") has 15 voting members and one non-voting member in its board of directors.[31] Meanwhile, PJM's board is composed of nine voting members plus the Chief Executive Officer or President who is a non-voting member.

---

[27] OASIS provides information about transmission capability and a process for requesting transmission service.

[28] Ibid, page 323.

[29] FERC. Regional Transmission Organizations (Issued December 20, 1999) (Docket No. RM99-2-000; Order No. 2000), page 151.

[30] CAISO. *Board Selection Policy.* June 13, 2016. <http://www.caiso.com/Documents/BoardSelectionPolicy.pdf>.

[31] ERCOT. *ERCOT Quick Facts.* <http://www.ercot.com/content/wcm/lists/144926/ERCOT_Quick_Facts_41018.pdf>

Like other ISOs, PJM's Board oversees the ISO's operations, approves budget and staffing, and approves changes to market rules. In addition, the Board is responsible for the ISO's safety and reliability, as well as ensuring competitive and nondiscriminatory electric power markets. In PJM, the Board is advised by stakeholder groups and advisory committees that recommend changes to market rules and operating guides. For PJM, the voting Board members are elected for three-year staggered terms by the Members Committee.[32] The Members Committee consists of five sectors representing generation owners, transmission owners, electric distributors, other suppliers, and end-user customers.[33]

Meanwhile, for California ISO, a search firm chosen by the ISO is responsible for seeking out candidates for consideration by the Board Nominee Review Committee.[34] The Board Nominee Review Committee is composed of 36 members with each representing one of six member-classes that include transmission owners, end-users and retail energy providers, public interest groups, alternative energy providers, transmission-dependent utilities, and generators and marketers.[35] This committee ranks each candidate in descending order, and the ISO forwards the list of candidates (with ranking) to the Governor of the State of California for consideration.[36] Appointees are subject to confirmation by the state Senate, as outlined in the Public Utilities and Government Codes.[37] Similar to the PJM Board, the board of California ISO reviews and approves the annual ISO budget, shapes policies and approves grid planning and market design changes.[38]

As a not-for-profit company, an ISO funds the services it provides by collecting fees from the market participants and customers that use regional transmission services.[39] The service rates are set at a level that let the ISO recover operating costs, while the amount is determined each year through the budget process which includes a robust external stakeholder review process. After the approval of the budgets by the independent Board of Directors, they are filed with FERC.[40]

---

[32] PJM. Governance. Website. Access Date: April 20, 2018. <https://learn.pjm.com/pjm-structure/governance.aspx>

[33] PJM Governance Fact Sheet. Website. Access Date: April 20, 2018. <https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/governance-fact-sheet.ashx>

[34] California ISO. *Board Selection Policy Version #4.4*. 2016. Page 1.

[35] Ibid, page 3 - 4.

[36] Ibid, page 4.

[37] Ibid, page 4.

[38] California ISO. The Board of Governors guides our direction. Website. Access Date: July 11, 2018. <http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx>

[39] ISO-NE. The ISO's Funding and Budgeting Process. Website. Access Date: April 20, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[40] ISO-NE. The ISO's Funding and Budgeting Process. Website. Access Date: April 20, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

Since Hawaii is not within FERC's public utility-related statutory authority, an ISO could report to the Hawaii PUC, similar to how ERCOT does it—by reporting to the Public Utility Commission of Texas.

Maui County: Guernsey study recommended the ISO/ RTO model

Tasked by the County of Maui, Guernsey completed an options analysis for electrical utility service within the County and released the report in December 2015. The study suggested the ISO/ RTO regulatory model for Maui County because of the following advantages:

- ***little physical infrastructure:*** ISO/ RTO acquires existing dispatch, monitoring and control equipment, but the great majority of generation assets, transmission and distribution wires remain with MECO;
- ***quickest implementation:*** given enough political willpower this route could be completed much more quickly than a negotiated sale or condemnation of the MECO assets;
- ***implementable regardless of potential merger:*** this approach can be implemented regardless of the outcome of HEI/NextEra merger; and,
- ***promoting competition and transparency:*** this approach promotes competition by providing clear price signals and market transparency so that power producers of all types can make rational economic decisions; this approach also optimizes transmission planning such that all power producers are incorporated into planning and infrastructure improvement efforts.

Note: While LEI quotes the findings here, LEI does not necessarily endorse this approach.

Source: Guernsey. *County of Maui: Analysis of Alternative Forms of Ownership and Alternative Business Models for Maui County's Electric Utility Company*. December 23, 2015.

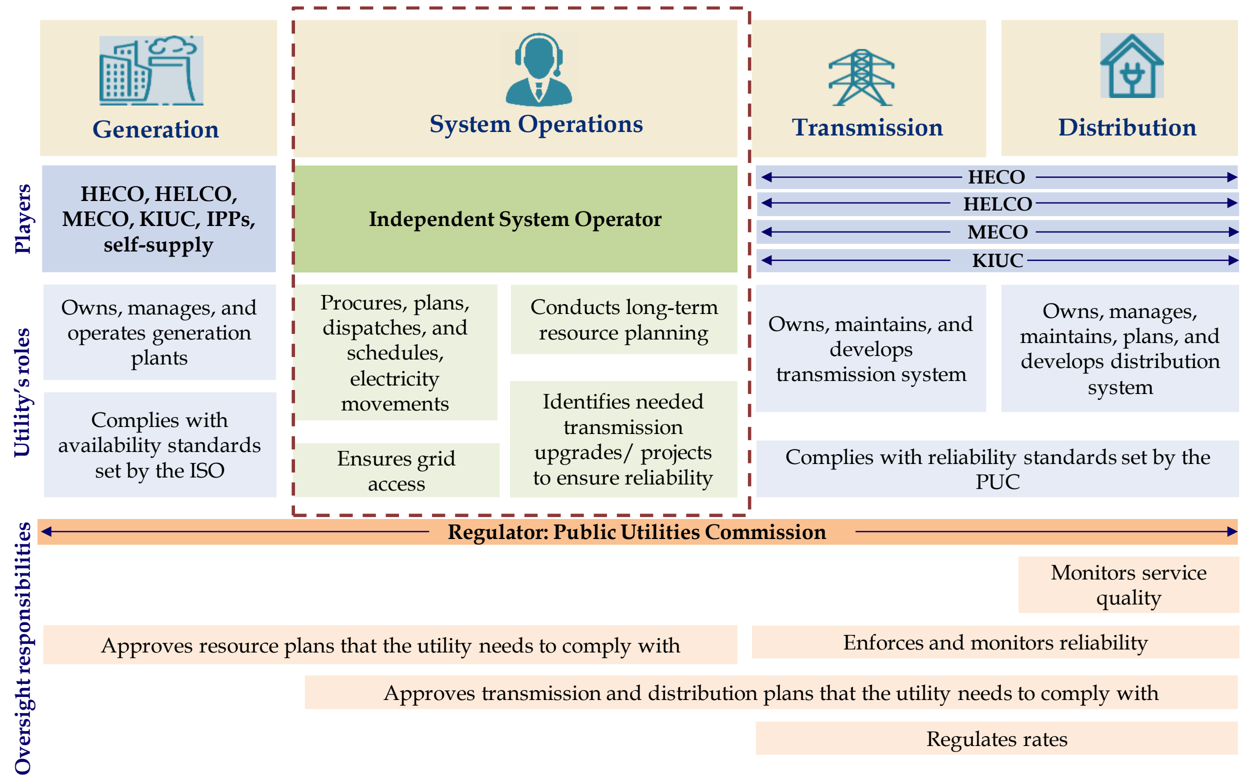
Although Hawaii is outside of FERC's and NERC's jurisdiction, an ISO or RTO could be formed in the State without participating in interstate commerce to accomplish the objective of system planning and dispatch. The box above enumerates the advantages of the ISO/RTO model, based on the study undertaken by Guernsey for the County of Maui in 2015.

3.3.1 Oversight under an ISO model

Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities yield their functions of system planning, dispatch, and day-to-day operations to the ISO. Under an ISO model, the incumbent utility could either retain its generation assets or divest them. In contrast to the status quo, this change allows independent power producers ("IPPs") to compete with the incumbent vertically integrated utilities on price in the wholesale market.

The PUC's oversight on resource planning, power purchase agreements, utility's transactions, significant capital expenditure, service quality, and rates would remain the same. However, the tasks on reliability and long-term resource planning would be delegated to the ISO. The utility's previous role of coordinating movements of electricity would be transferred to the ISO as well, as shown in Figure 6.

Figure 6. Graphical depiction of the value chain under an ISO model



3.3.2 Jurisdictions in the US under an ISO/RTO structure

Currently, there are nine ISOs/RTOs in North America as shown in

Figure 7 and Figure 8. These include Alberta, California, Ontario, New York, Midcontinent ISO, New England, PJM Interconnection, Southwest Power Pool, and ERCOT. A case study of an ISO will be discussed in detail in Task 2.2.2.

Figure 7. RTOs/ISOs in North America

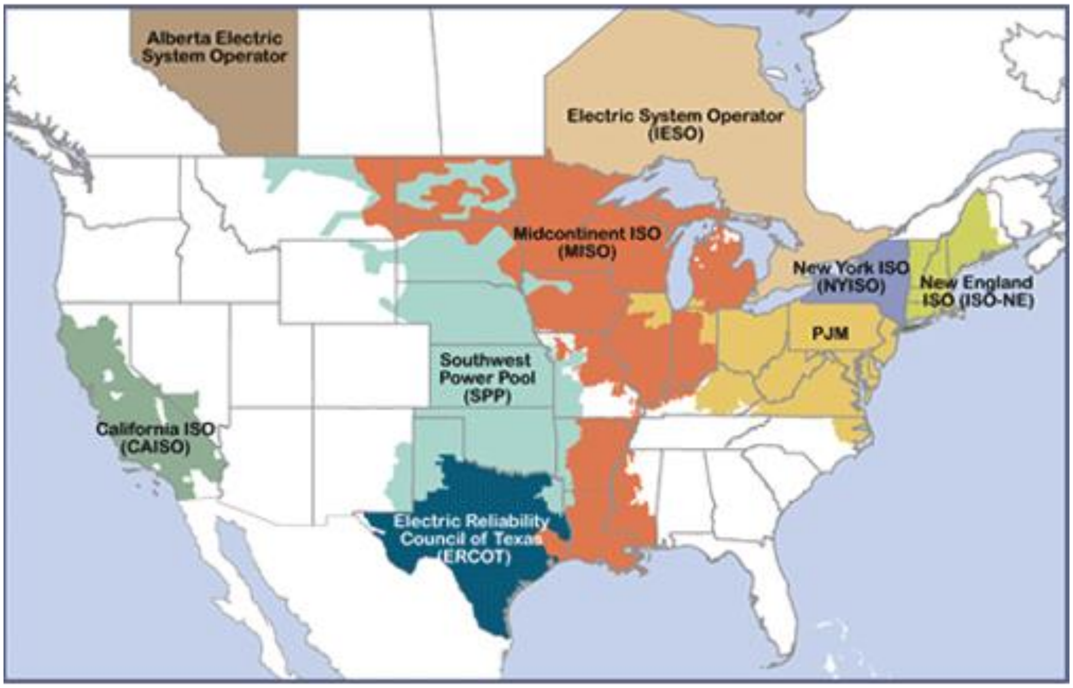


Figure 8. List of potentially relevant jurisdictions that have RTOs/ISOs in North America

ISOs	Year of establishment	Single-jurisdiction ISO?
ERCOT	1996	Y
PJM	1996	N
ISO-NE	1997	N
CAISO	1998	Y
IESO	1998	Y
NYISO	1999	Y
MISO	2001	N
AESO	2003	Y
SPP	2004	N

3.4 Distribution-focused regulatory model

Currently, utilities own and operate the distribution grid. Although there are third-party entities such as solar installers, the technologies must still be connected to the utility grid. However, with the rapid growth of rooftop solar and the advancement of grid technologies, some markets have started to consider alternative business models for the distribution grid. A good example of a distribution-focused regulatory model is New York's Reforming the Energy Vision ("REV"). Like Hawaii's State goal, New York targets increasing the use of clean energy and customer participation in the electricity sector. Its REV initiative is fundamentally shifting the role of the utility from an entity that develops and maintains transmission and distribution assets (utilities in New York are generally not allowed to own generation assets) to an entity that enables the localized management of electricity supply and demand.

There are two potential models under a distribution-focused regulatory model. The first model is where the distribution system is still owned and operated by the incumbent utilities. This model is more like New York's REV where the distribution utility becomes the Distributed System Platform Provider ("DSPP"). The DSPP's new role, as envisioned by the New York regulator, would be responsible for "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs."[41] Under REV, to be able to do this the DSPP is required to "*use localized, automated systems to balance production and load in real time while integrating a variety of distributed energy resources ("DERs"), such as intermittent generation resources and energy storage technologies*."[42] Moreover, the DSPP is required to "*take steps to ensure that distribution systems continue to be modernized through the use of 'smart grid' technologies*" and "*coordinate its planning functions with the implementation by customers of customer-sited DER*."[43] However, this approach requires corresponding incentives in place to ensure that the utilities act in a way that supports the desired outcomes, i.e., allowing third-party access to the grid, making data available, etc.

The second model is where the distribution system is still owned by the utilities but operated by an outside entity. This external entity, which is called the independent distribution system operator ("independent DSO" or "IDSO"), would be under the purview of the PUC and operate and plan for the distribution system. The IDSO is expected to include the day-to-day operations of the grid and be responsible for planning for upgrades of the system. On the other hand, the utilities would maintain and invest for the distribution assets. The utilities would also participate in the planning and operational process of the IDSO. This is the same relationship that an ISO has with the transmission grid.

3.4.1 Oversight under a distribution-focused model

If utilities in the state shift to a DSPP role or have an independent DSO eventually, there would be a change in the current ownership structure of the electric value chain and the ratemaking process. Under the distribution-focused model, diversity of ownership structures for generation is presumed and no one ownership structure for generation need dominate. The transmission and distribution assets would still be owned and operated by incumbent utilities under the DSSP model. The DSSP would provide a distribution marketplace and coordinate with customer-sited DERs. Under the DSPP model, the PUC would also need to ensure fair competition in the distribution marketplace in addition to its current responsibilities.

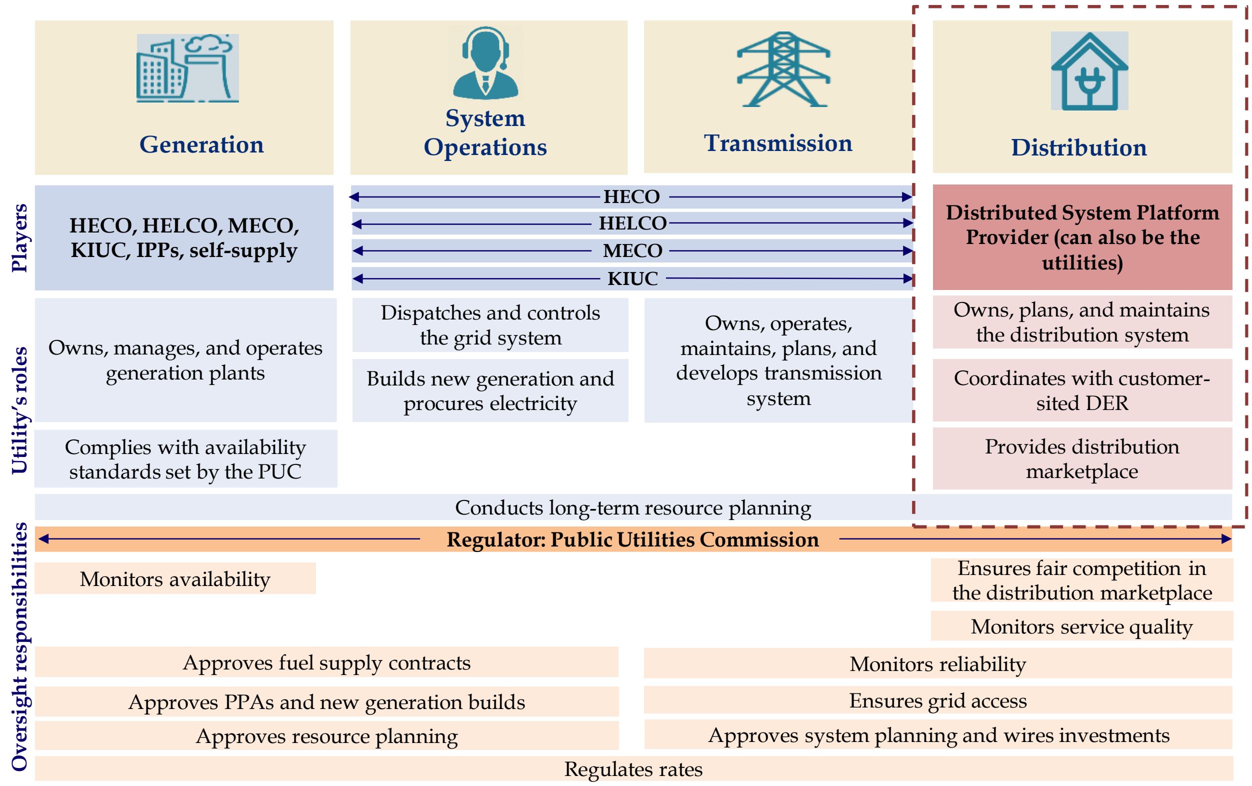
---

[41] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*. Order Instituting Proceeding (issued and effective April 25, 2014). Page 12.

[42] Ibid. Page 13.

[43] Ibid. Page 14 - 15.

Figure 9. Graphical depiction of the value chain under a DSSP model

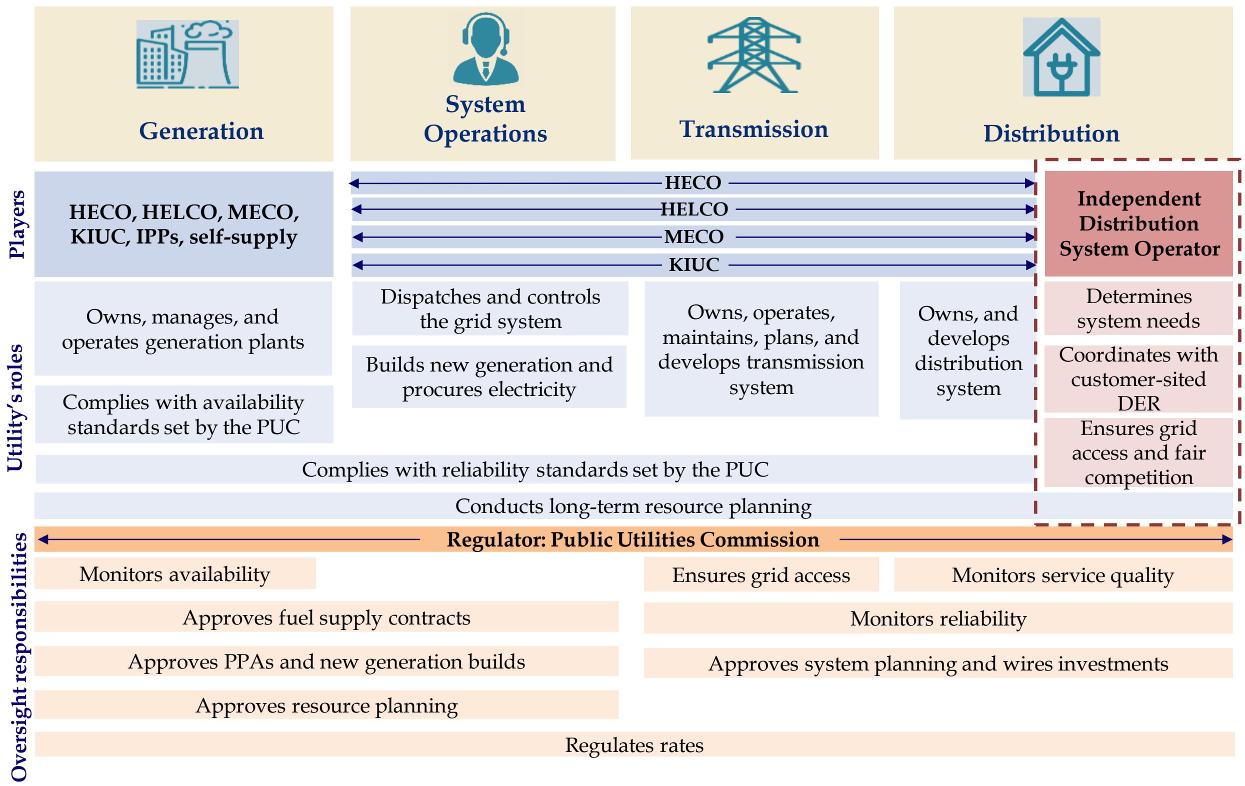


The ratemaking under a distribution-focused model would also change under the DSPP and DSO models. The COS approach would still be used in combination with market-based platform earnings and Outcomes-based earning opportunities, similar to what the New York's REV is proposing.[44] Under REV, utilities will have four ways of achieving revenues, namely, 1) traditional COS earnings; 2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; 3) profits from market-facing platform activities; and 4) transitional Outcomes-based performance measures.[45] Hawaii may consider some of these revenue mechanisms if it opts to do the DSPP model. These different earning opportunities will be discussed in detail in Task 2.2.3 (Financial Feasibility).

[44] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework (issued and effective May 19, 2016) (Track Two Order). Page 2.

[45] Ibid. Page 2.

Figure 10. Graphical representation of the value chain under a DSO model



3.4.2 Jurisdictions that are moving toward a distribution-focused regulatory model

Currently, there is no jurisdiction that has a full-blown distribution-focused regulatory model. However, according to the Lawrence Berkley National Lab, there are generally three stages on the DER adoption, namely: (i) grid modernization, (ii) DER integration, and (iii) distributed markets as shown in Figure 11.[46] Each stage is distinguished by the level of DER adoption in the system, and the technology in place to support DER integration:

- Stage 1 – DER adoption is reasonably low and can be accommodated by the existing technology levels in the grid. This stage represents the state of most existing distribution systems in the US.

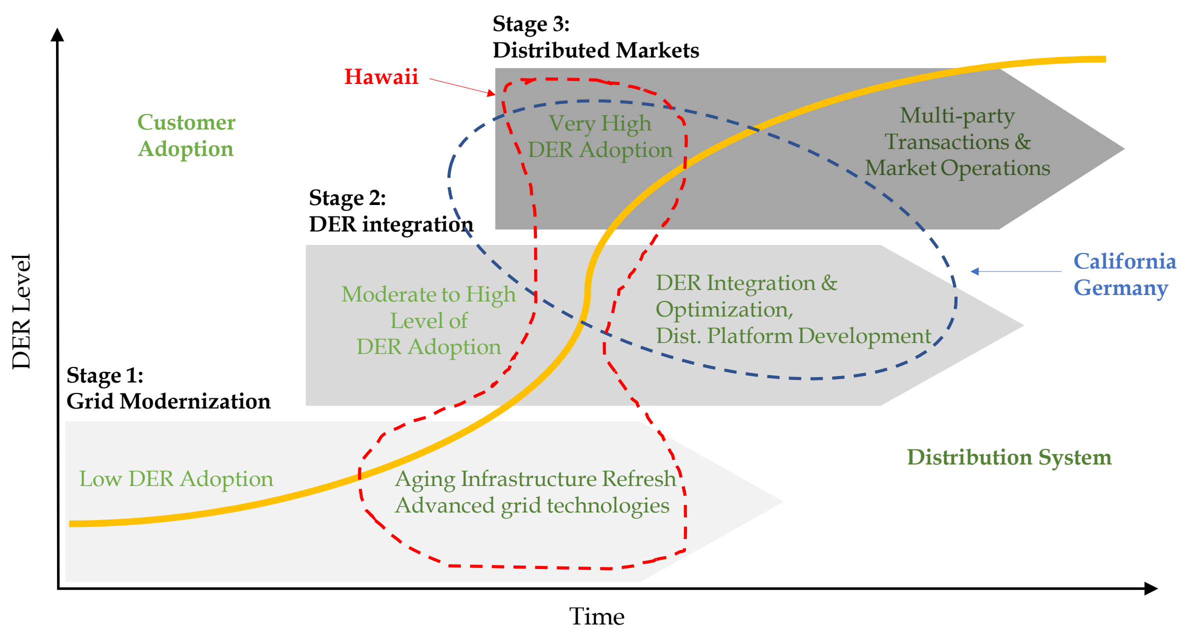
[46] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

- Stage 2 – DER adoption levels increase such that they are at the threshold level[47] that will require enhanced functional capabilities to ensure reliable system operation.

- Stage 3 – a combination of very high DER adoption, enabling system technology investment and policy decisions allow for the creation of distribution-level energy markets and multi-sided transactions.

As illustrated in Figure 11, DER adoption is uneven across multiple service territories and depending on the scale and nature of the adoption, would affect each system differently. However, at a conceptual level, it is possible to define a progression of levels of adoption, Figure 11 illustrates this adoption process as developed by DeMartini and Kristov in their report for Lawrence Berkeley National Lab's "Future Electricity Regulation" series.[48,49]

Figure 11. DER adoption curves



Sources: LEI analysis and DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

---

[47] The authors note that empirical evidence from jurisdictions at this level suggests that this level appears when DER adoption reaches beyond about 5 percent of distribution grid peak loading system-wide. (Source: DeMartini & Kristov. 2015).

[48] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

[49] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. November 2016.

Considering jurisdiction policies and DER penetration levels, the Project Team has identified where a few sample jurisdictions lie on the curve. Ontario and Vermont represent the same level of DER development, i.e., moderate to high level of DER adoption, spurred on by generous feed-in-tariffs and coupled with grid infrastructure not keeping pace with the investment.

New York represents the archetype of Stage 2, where a moderate level of DER adoption is also coupled with DER integration. The latter is driven by policy goals and implementation plans from the State government.

Both California and Germany are at varying levels of high DER adoption, spurred by generous feed-in-tariffs. By way of grid integration and optimization, both jurisdictions are driving increasing DER optimization through policy, such as in the case of California with its DER Action Plan. The Action Plan is intended to align DER policies into broad categories, targeting rates, distributed generation ("DG") infrastructure, and market integration.

Hawaii's high DER adoption levels and State policy promotion alongside lagging infrastructure investment levels place it in Stage 2 like New York. The HECO Companies' Grid Modernization Strategy may improve infrastructure such that it could begin the transition towards the third stage, thereby moving closer to or become similar to California.[50]

3.5 Performance-based regulation model

To design an optimal PBR framework, it is first necessary to define performance. In the past, the performance and roles expected from electric utilities, including those in Hawaii, focused on providing adequate and reliable energy supply, maintaining service quality, and complying with technical standards set by the regulator.

However, the energy industry is changing. For instance, the future requires that the energy sector is developed in a way that the electricity system would be able to accommodate more smaller renewable plants and DERs. Particularly, there is an increasing availability of customer-sited and distributed generation in Hawaii. Moreover, the State is pursuing the shift from fossil fuel-based to renewable energy generation.

The current COS regulation may no longer provide the incentives that would encourage the utilities to meet the challenges of renewable and distributed energy future. With these transformations, the performance expected from electric utilities would also need to change. In fact, the performance and role expected of the utilities have been expanded to cover other aspects of the business.[51] Through the *Goals and Outcomes for Performance-Based Regulation in Hawaii:*

---

[50] It is worth noting that while California is ahead in terms of infrastructure and regulations governing DERs, Hawaii has significantly higher level of DER adoption. The impact is further magnified in Hawaii since it is a much smaller system and each island has its own grid that is not interconnected with other islands. This makes it more important for Hawaii to ensure its grid infrastructure and regulations on DERs keep pace with adoption levels.

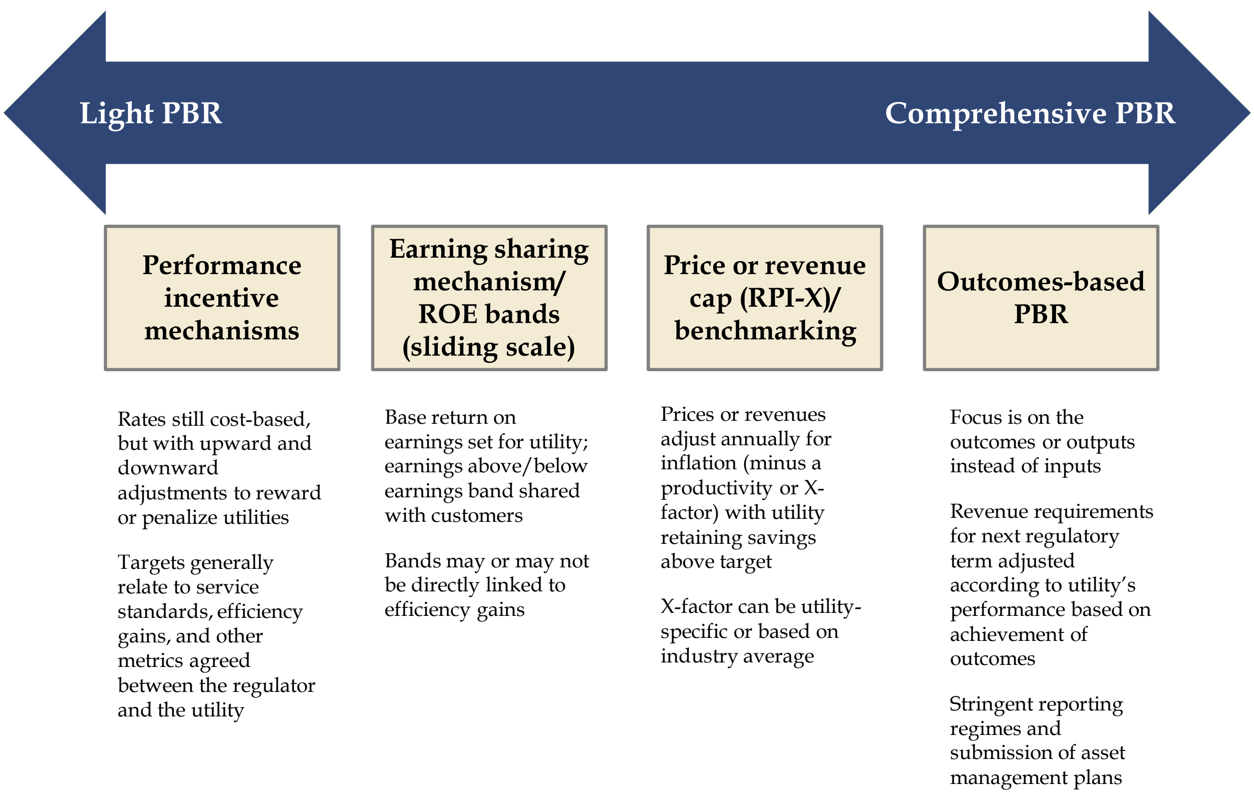
[51] For example, according to a 2017 report on electric utilities performance benchmarking, 257 Key Performance Indicators could be considered, which are clustered in five main categories, namely 1) customers, 2)

Concept Paper to Support Docket Activities under Docket 2018-0088, the PUC has identified potential areas where the HECO Companies' performance will be measured under PBR. These include enhancing customer experience, improving utility performance, and advancing societal outcomes.[52]

3.5.1 PBR as a tool to strengthen utility performance

PBR, compared with traditional COS, can induce desirable changes to utility behavior. PBR can include a variety of mechanisms that could be used in multiple ways and different combinations. PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime.

Figure 12. Continuum on PBR regulation from "light" to "comprehensive" key mechanisms



Light PBR includes mechanisms—such as PIMs and ESMs—where payments to the utilities are adjusted based on their level of performance. The "medium" form of PBR mechanism includes the rate cap where either the price or the revenue is capped for the regulatory period. This helps promote efficiency as the mechanism tends to change the link between a utility's rates and its

operations, 3) environment, 4) human capital, and 5) corporate governance. It should be noted that these are examples, and that any tractable regime would have considerably fewer metrics.

[52] Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018. Page 2.

costs and improves efficiency. At the end of the continuum is Outcomes-based PBR, which is the new generation PBR, where the focus is on the outcomes rather than the inputs to the revenue requirements. Each of these mechanisms will be discussed in detail in the following subsections.

The "right" form of PBR depends on the needs and values of the particular jurisdiction—each may be appropriate depending on the circumstances. Generally, the choice of light versus comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be considered as "stepping stones" towards the comprehensive PBR mechanism.

Aside from these key PBR mechanisms, there are also other components such as the length of the multi-year rate plan, productivity factor, treatment of unforeseen events or exogenous factors, off-ramp option, and flow-through factors. These will be discussed in Section 3.5.1.5.

3.5.1.1 Performance incentive mechanisms

With PIMs, payments to utilities are adjusted upwards or downwards based on the utilities' level of performance. PIMs involve metrics, targets, and incentives used to examine, evaluate, and enhance a utility's performance over time by providing information on industry trends and opportunities.

PIMs must support the utilities' strategic goals and be achievable, realistic, and measurable. For instance, if one of the utility's goals is "to become a trusted community and business partner delivering valued energy services,"[53] then its PIMs should include service performance and community regard indices. PIMs should be attainable, and utilities and the regulator should cooperate to design challenging, yet realistic standards. Moreover, PIMs must also be consistent with customer needs or expectations and what they are paying for.

Utilities use different PIMs for different sectors of the value chain. For instance, performance is typically measured in terms of efficiency and availability in generation while frequency and duration of outages and customer service metrics are used in the wires sector. Aside from balancing cost efficiencies and reliability, other areas for performance measurement in the wires sector include metering, billing and collection, customer service, and employee safety.

PIM targets are set either by examining historical performance, or focusing on desired outcomes (e.g., comparing it with counterparts'), or through technical or statistical methods. Past performance should provide insights to what the utility can achieve. Another approach is by benchmarking with peer groups. This would help identify areas where opportunities for improvement exist. With a large-sized sample, overall industry patterns reveal trends in performance.

Setting the potential rewards and/or penalties is a balancing act. Rewards and penalties should be significant enough to incentivize the utilities to perform better. They should also be reflective

[53] Energex. *Statement of Corporate Intent*. Energex website. Energex is an Australian electric power distribution company owned by the Government of Queensland.

of the actual cost to remedy performance shortfall. Generally, rewards and/or penalties under PIMs are based on deviations set in percentage terms or standard deviations from performance targets. Lastly, in determining and setting PIM targets, there should be a balance between the utility's financial viability and customer expectations and willingness to pay. Caps on the amount of exposure to performance fines act as an insurance mechanism to ensure the utility's economic sustainability. Furthermore, rate increases may be required to increase performance significantly and/or maintain exceptional performance targets.

Numerous markets have implemented PIMs. Most of these PIMs are focused on reliability and service quality metrics. Figure 13 shows an example of distribution performance incentives that are both financial and non-financial.

Figure 13. Sample jurisdictions that have PIMs

	Consolidated Edison of New York	Central Maine Power	New Brunswick Power	San Diego Gas and Electric	Ontario
Term of Tariff Plan	2010-2013	2008 – 2014	2013 - present	1999-2002	2009-2011
Rewards, Penalties or Both	Penalties Only	Penalties only	Penalties Only	Both Rewards and Penalties	Nonfinancial measures
Explicit Formula (Yes/no)	Yes	Yes	No	Yes	No
Reliability Metrics	SAIFI, SAIDI, other reliability investment metrics	CAIDI, SAIFI	All mandatory NERC Standards	CAIDI, SAIFI, MAIFI	SAIFI, SAIDI, CAIDI
Service Quality Metrics	Customer complaints, customer satisfaction, call answer rates	Complaint ratio, calls answered (%), call center quality, meters read, new connections	No explicit service quality standards tracked and subject to fines from the Energy and Utilities Board	Customer satisfaction, call center response, all injury frequency rate	New connections, underground cable locations, telephone accessibility, appointments made, emergency and written responses
Max Penalty	$152 Million	$5 million	N/A	$14.5 million	N/A

Notes:
AIFI - Average Interruption Frequency Index calculates the average number of momentary interruptions that a customer would experience in a given period.
CAIDI - Customer Average Interruption Duration Index ("CAIDI") measures the total duration of an interruption for the average customer and can be calculated as a ratio of SAIDI and SAIFI, provided they are calculated over the same period.
SAIDI - System Average Interruption Duration Index ("SAIDI") measures the total duration of an interruption for the average customer in a given period, typically in hours or minutes per year.
SAIFI - System Average Interruption Frequency Index ("SAIFI") measures the average number of times that a system customer experiences an outage in a given period and is usually calculated on an annual basis

Sources: California Public Utilities Commission ("CPUC"), Maine Public Utilities Commission ("MPUC"), New Brunswick Energy and Utilities Board, New York State Public Service Commission ("NY PSC"), and Ontario Energy Board ("OEB").

HECO Companies' PIMs

HECO Companies report performance metrics in eight categories to the PUC, including:

- service reliability,
- power supply and generation,
- renewable energy,
- customer service,
- financial,
- safety,
- rates and revenues, and
- emerging technologies.

The metrics under most of these categories are tracking-only metrics, without associated rewards or penalties.

Among these performance metrics, only System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and call center performance are PIMs that are included in ratemaking. The PUC recently also approved PIMs related to HECO Companies' achievement of cost savings in renewable generation procurement and implementation of demand response ("DR") portfolio.

Source: Order 35411

3.5.1.2 Earnings sharing mechanisms

An earnings sharing mechanism is another mechanism under PBR. ESMs are designed so that the extraordinary earnings (or losses) are shared among the company and its customers rather than retained (or absorbed) entirely by the company if formulae-driven price adjustments result in a significant divergence between prices and costs.[54]

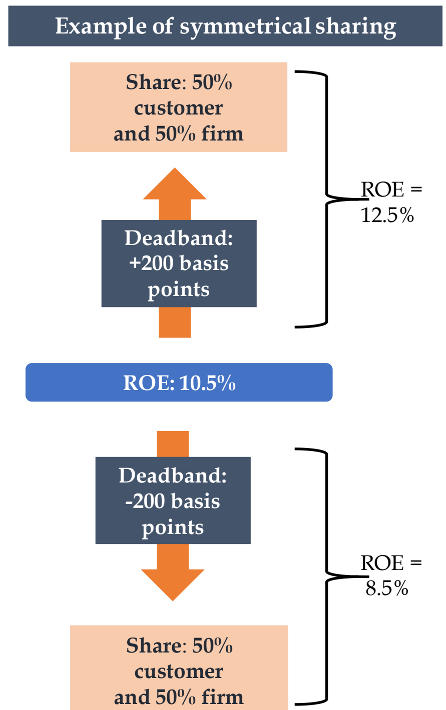
Generally, ESMs involve three elements, namely, (i) a target return on equity ROE, (ii) a deadband around the ROE in which no sharing takes place, and (iii) sharing of gains or losses, which are outside the deadband. The ROE is the regulator-approved return for the utility. The deadbands allow customers to participate in gains without requiring extensive regulator involvement. The sharing percentages are the level of sharing between the utility and customers.

Deadbands and sharing percentages can either be symmetrical or asymmetrical. Customers share both upside and downside risks equally under the symmetrical system while customers or the

[54] Such mechanisms serve the same basic purpose—ensuring prices do not get too distorted or deviate too much from actual costs—as in the case of clawbacks within a traditional COS system. In the context of indexation formulae, an alternative and a more drastic one to an ESM is an exit ramp, which triggers an automatic end to the current formulae application period (and thereby initiates a COS rate review) if prices deviate too much from costs.

regulated utility are taking on a disproportionate portion of the risk under an asymmetrical system. Figure 14 shows an example of an ESM with a symmetrical deadband and sharing percentages.

Figure 14. Example of a symmetrical sharing



However, there are also some identified drawbacks to ESM. First, an ESM can complicate the administration of a PBR system.[55] Second, ESM reduces the efficiency incentives created by shifting to PBR if attached to a productivity factor target. Some argue that a successful PBR implementation does not require an ESM. Nevertheless, many believe that by allowing customers to share in benefits--which arguably would not occur in the absence of incentives--the overall political acceptability of a PBR plan may also be increased. For instance, true-ups under a symmetrical ESM mechanism can neutralize the perceived impact of rate increases in the re-basing or review stage.

Although ESMs are not a feature of all PBR regimes, they are commonly used across the US and are unusual outside North America. A sample of provisions of these ESMs across the US is shown in Figure 15.

[55] For instance, during its first generation PBR, ENMAX was concerned with the information and retail requested by the intervenors and the Commission in the process of determining the earnings sharing amount.

HECO Companies' ESM

In the case of the HECO Companies, the ESM is asymmetrical where only above threshold earnings (i.e., where utility earnings are greater than the authorized return on equity ("ROE")) are shared with the customers. This means that where there are no above threshold earnings (i.e., earnings are at or below the authorized ROE), any lower than expected earnings will be fully absorbed by the utility's shareholders and not by its ratepayers.

In other words, if the utilities' ROE is at or below the authorized ROE, any earnings will be retained entirely by shareholders. If the actual ROE is more than 100 basis points or 1% over the authorized ROE, customers will be credited a 25% share. If the actual ROE is more than 200 basis points or 2% over the authorized ROE, the customers will get a 50% share. If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers get a 90% share.

Source: Order No. 35411, at 43

Figure 15. Selected jurisdictions and their ESM provisions

Company Name	US State	Term	Sharing Mechanism
Central Hudson Gas & Electric	New York	Jul 1, 2010-Jun 30, 2013	Actual regulatory earnings in excess of 10.50% and up to 11.00% will be shared equally between ratepayers and shareholders. Actual regulatory earnings in excess of 11.00% and up to 11.50% will be shared 80/20 (ratepayer/shareholder). Actual regulatory earnings in excess of 11.50% will be shared 90:10 (ratepayer/shareholder).
Florida Power & Light Co.	Florida	2006-2009	FPL's shareholders will receive a 1/3 share and FPL's retail customers will receive a 2/3 share.
Narragansett Electric	Rhode Island	Feb 1, 2013-Jan 31, 2014	Earnings between 9.5% and 10.5% are shared 50:50 between the utility and its ratepayers, while earnings in excess of 10.5% return are shared 25:75.
NSTAR	Massachusetts	2007-2013	ESM dead band is 8.5%-12.5%. If ROE is above/below the dead band, the earnings are shared 50:50.
San Diego Gas & Electric Co.	California	2005-2007	The sharing mechanism contains a symmetrical 50 basis points "inner dead band" and six sharing bands between 50 and 300 basis points above or below the authorized ROR. Shareholders receive 25 percent of the earnings above or below the authorized ROR in the first band, increasing by 10 percent in each subsequent band.
United Illuminating Co.	Connecticut	Jan 11, 2006-Dec 31, 2009	ESM is based on sharing of earnings above target ROE (9.6%) where 50% is retained by the shareholder, 25% goes to customers through bill credits and the remaining 25% goes to reduce the customer's balance of standard costs.

Sources: State of New York Public Service Commission, Florida Public Service Commission, Rhode Island Public Utilities Commission, Massachusetts Department of Public Utilities, California Public Utilities Commission, State of Connecticut Department of Public Utility Control

3.5.1.3 Rate caps

Unlike a rate freeze, rates under rate caps could change during the regulatory term, based on the approved formula. More specifically, utility's rates are adjusted annually through an indexing formula that tracks the inflation rate; less an offset to reflect the improvements in productivity that the utility could expect to achieve during the regulatory period. Under a rate cap, the utility is required to perform annual productivity improvements. Furthermore, with a rate cap, a utility's revenues are allowed to diverge from its costs during the regulatory period. The decoupling of costs and revenues incentivizes the utility to increase productivity and decrease costs.

Price caps and revenue caps are examples of rate caps. The critical difference between price and revenue cap regimes is related to what the PBR formula applies to – rates in the case of price cap regimes, and revenue requirements in the case of revenue cap regimes.

Under a **price cap**, which is also called price indexing or rate indexing, the regulator approves a formula that determines how fast rates can increase. The regulator sets an ***initial price,*** and the rates are adjusted for each year taking changes in inflation and productivity into account. A price cap provides incentives for cost efficiency and increase of sales. These incentives arise because the tariff is fixed for the regulatory period and would not vary with changes in electricity sales within the regulatory period. Another advantage of a price cap is that it provides greater rate predictability for customers.

A price cap regime is best suited for utilities in an environment with stable or increasing demand as it provides incentives for them to operate cost-effectively while meeting the growing demand. Under a price cap, the utilities' revenues could grow with new customers and growth in demand from existing ones. The additional revenue contributes funding for the increased capital and operating costs of serving new customers and additional load. However, utilities operating under a price cap regime are also exposed to revenue risk associated with actual electricity sales varying from forecasts of electricity sales used to set the rates.

On the other hand, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, the ***revenue requirement*** in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, which considers changes in inflation and productivity.

Under a revenue cap, there is no incentive for utilities to maximize sales, but there is still an incentive to minimize overall costs, making it arguably more compatible with utilities that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes.

The advantages and disadvantages and where these two rate caps are suitable will be discussed in Appendix A.

3.5.1.4 Outcomes-based PBR

At the comprehensive end of the PBR is Outcomes-based PBR. Outcomes-based PBR focuses on the outputs or outcomes of the PBR plan, rather than activities, which is generally the emphasis of the traditional rate filing.

The utilities in an Outcomes-based PBR are expected to achieve the outputs that are set during the PBR filing (or before the implementation of PBR). These outcomes could be grouped into different categories such as reliability and availability, operational effectiveness, safety, public policy responsiveness, customer satisfaction, financial performance, and environment, to name a few.

A good example of a jurisdiction under the Outcomes-based PBR is the UK's RIIO model, which stands for **R**evenue set to deliver strong **I**ncentives, **I**nnovation, and **O**utputs. Under the RIIO model, the transmission and distribution utilities in the UK are encouraged to "*play a full role in the delivery of a sustainable energy sector*[56] *and deliver value for money network services for existing and future consumers.*"[57]

This model requires utilities to submit robust business plans that demonstrate that they are proposing the best option in terms of meeting the goals of the RIIO model.[58] The business plans include data such as the utilities' forecasts for network replacement, and capacity additions, to name a few.

A more detailed discussion about the RIIO model will be discussed in Task 2.2.2. (Case Studies).

3.5.1.5 Other potential PBR parameters

Other jurisdictions use other PBR components alongside the mechanisms mentioned above. These other parameters – which add to the PBR formula -- include treatment of (certain) capital expenditures and unforeseen events, length of the regulatory period, and triggers for an "exit" or "off-ramp." Along with the mechanisms discussed above, the PBR parameters are shown in

---

[56] Ofgem defines sustainable energy sector as "an energy sector that meets the broad needs of existing and future consumers. This includes delivery of low carbon energy and other environmental objectives, delivery of secure, safe supplies and delivery of value for money including meeting the needs of vulnerable consumers," from the Handbook for Implementing the RIIO Model.

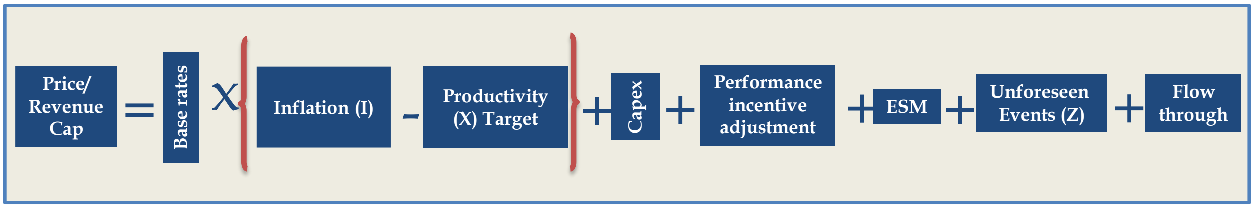
[57] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. Page 2.

[58] Ofgem. *Handbook for Implementing the RIIO Model*. October 4, 2010. Page 48.

Figure 16.

Determining the individual PBR components requires careful consideration and these components need to be viewed holistically. Therefore, in determining the appropriate parameters and their combinations, the choice of one parameter influence the others. For example, the productivity factor is not independent of the inflation factor because an inflation index using macroeconomic Outcomes-based measures takes some level of productivity gains into account. Also, utilities would consider the regulatory term of PBR depending on how they perceive their abilities to perform under a PBR regime. For example, a well-performing utility may assume that a longer regulatory term under PBR would provide a more extended period for it to reap the "rewards" of cost gains, while utilities that are not confident about achieving their productivity target may view a shorter period as a lower risk proposition.

Figure 16. Key components to consider for a PBR formula



Components	Purpose
Going-in rates	Starting point of the PBR regulatory term. Rates usually determined through a COS filing (or rebasing). The PBR annual adjustment (I – X) is subsequently applied to those rates during the regulatory period
Regulatory period	Scheduled time lag between two major reviews of the underlying components of the ratemaking regime
(I) - Inflation/ escalation factor	Annual adjustment to the utility's revenue or rates reflecting the level of inflation, usually reflecting the actual inflation rate in the previous year
(X) - Productivity factor / stretch factor	Annual adjustment to revenue or rates reflecting expected changes in terms of productivity. May be based on the utility's historical performance or on external benchmark. May include a firm-specific target, or stretch factor
(K) - Capital expenditure or (G) Growth factor	Annual adjustment to the utility's revenue or rates reflecting forecasted capital expenditure (capex) needs or ex post approval of capex spending in the previous year
(Q) - Performance standards factor/ PIM	Contingent adjustment to revenue or rates for rewards/penalties linked to the achievement or failure to reach specified performance targets, usually in terms of service quality as well as reliability and quality of supply
(ESM) - Earnings sharing mechanism	Mechanism through which a specified portion of a utility's profits in excess of/below the approved return on equity/forecasted level of expenditures is returned to customers
(Z) - Unforeseen events factor	Contingent adjustment to revenue or rates in order to recover extraordinary costs that are outside of the company's ability to control or predict
Regulatory review / Off-Ramp option	Mechanism allowing to trigger, under specified circumstances, a review of the ratemaking regime in place before the end of the regulatory period. The process may lead to the overhaul or the termination of the regime
(F) - Flow-through factor	Contingent adjustment to revenue or rates reflecting certain cost event are automatically passed through to customers as they arise, without having to be approved by the regulator

3.5.2 Jurisdictions under PBR

PBR regimes exist in multiple jurisdictions throughout the world as shown in

Figure 17. In North America, the markets that have used or is currently using PBR rate caps include British Columbia, Alberta, Ontario, Oregon, California, New York, Maine, and Massachusetts. PBR mechanisms used by markets in North America include PIMs, ESM, and rate caps. It is only Ontario that is currently implementing an Outcomes-based PBR, which they call customized PBR. Countries outside of North America, such as the UK and Australia, utilize a more comprehensive combination of PBR mechanisms. Some countries in Asia, such as Malaysia and the Philippines, are also implementing comprehensive PBR mechanisms. A list of potentially relevant jurisdictions that have PBRs is shown in the map below.

Figure 17. Jurisdictions that have used, or are currently using or plan to move to PBR

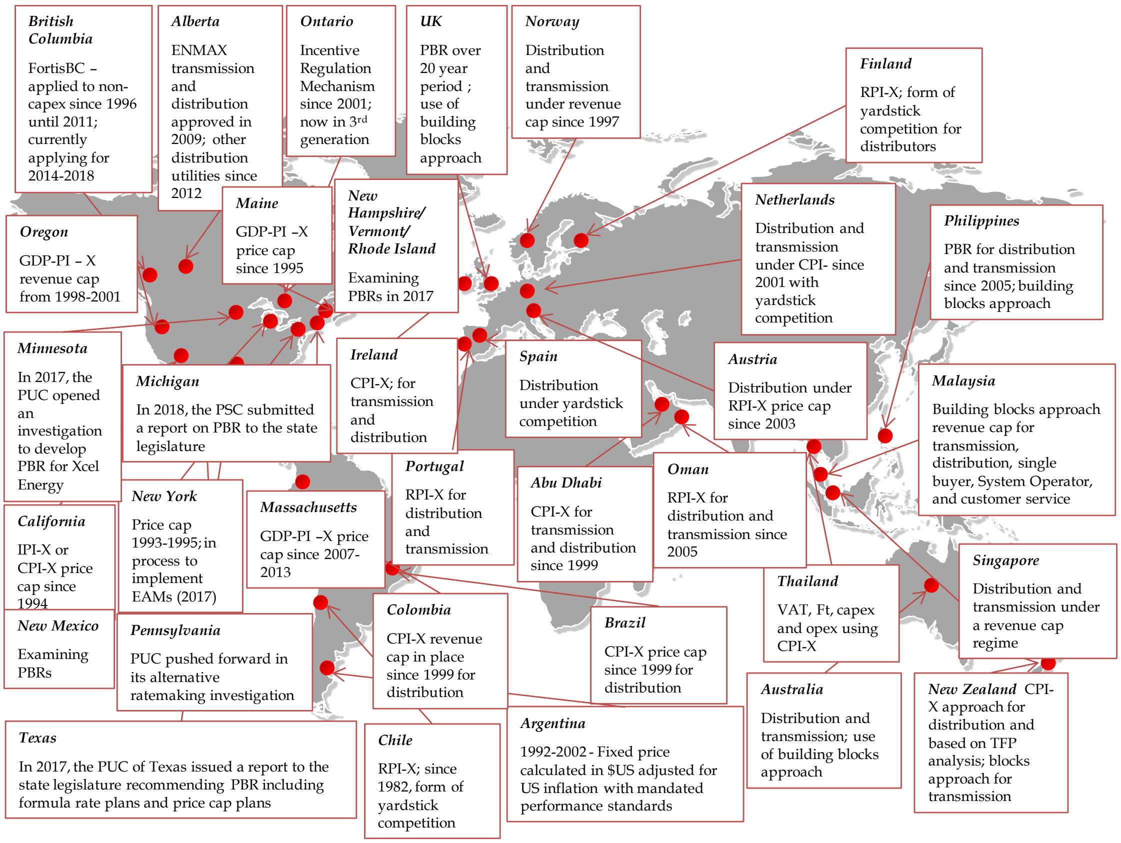


Figure 18. Sample jurisdictions that have used, are currently using, or plan to move to PBR

International	
Jurisdiction	**Type of PBR**
Alberta	Price cap (distribution), revenue cap (transmission)
Australia	Revenue cap (transmission), price cap (most distribution)
British Columbia	Price cap
Malaysia	Price cap (customer services), revenue cap (transmission, system operator, single buyer - operational), actual costs (single buyer)
Ontario	Price cap
Philippines	Price cap (maximum average price)
UK	Price cap, RIIO
States in the US	
States	**Type of PBR**
California	IPI-X or CPI-X price cap (1994 - 2000s), PIMs
Illinois	NextGrid initiative, PIMs
Maine	GDP-PI - X (1995 - 2013)
Massachusetts	I-X (Total Factor Productivity method)
Minnesota	Performance metrics for Xcel Energy
New York	REV, Earnings Adjustment Mechanisms
Ohio	PowerForward initiative
Oregon	GDP-PI - X revenue cap (1998-2001)
Rhode Island	Power sector transformation initiative

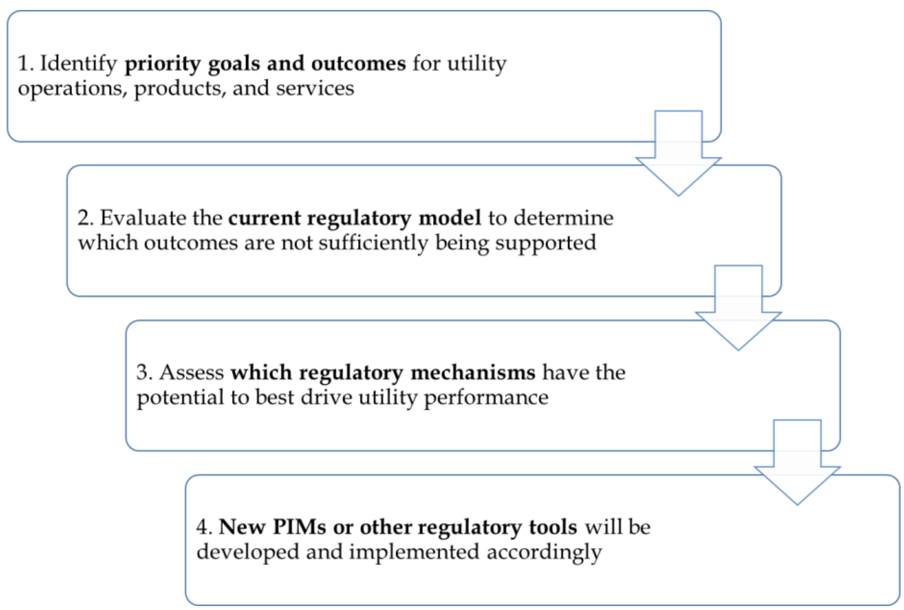
Note: this is not an exhaustive list; Illinois, Minnesota, Ohio, and Rhode Island are studying PBR as part of a broader power sector transformation initiative
Source: LEI study; Hawaii PUC. Order 35411 Instituting a Proceeding to Investigate PBR. Docket 2018-0088.

3.5.3 PBR in Hawaii

The Governor of Hawaii signed Senate Bill 2939 (now known as the Ratepayer Protection Act) into law on April 24, 2018. The law directs PUC to have performance incentives and penalty mechanisms that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, "*rapid integration" of renewables, including third-party home solar and storage systems, and "timely execution of competitive procurement ... and other business processes."*[59]

The PUC also opened docket 2018-0088 to investigate performance-based regulation and get inputs from stakeholders regarding the current regulatory model, specific areas of utility performance that should be improved, and the PBR frameworks that will be developed to increase the alignment between the utilities' interests and those of the customers. In contrast to the performance incentive mechanisms where the purpose is to *"provide financial rewards and/or penalties for utility performance according to specific metrics, without necessarily requiring a substantial change to other ratemaking procedures,"* the PBR framework "*constitute[s] a wholesale change in the regulatory procedures and cost control incentives associated with the traditional ratemaking process by, among other things, allowing utilities to profit from realized cost efficiencies and to establish financial rewards or penalties based on utility performance according to specific incentive metrics."*[60]

Figure 19. Hawaii PUC's conceptual framework to guide the PBR process



Source: Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018. Page 2.

[59] SB2939. Ratepayer Protection Act.

[60] PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 37.

The PBR would only apply to the HECO Companies because *"… as a member-owned, non-profit electric utility cooperative … KIUC is unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit, investor-owned utilities like the HECO Companies*."[61]

The current regulatory framework also has some components associated with PBR. These include a fixed three-year cycle for general rate cases, the decoupling mechanism, an ESM, an interim-period revenue adjustment mechanism which includes a revenue cap, and PIMs. A more detailed discussion of the proposed PBR for Hawaii will be covered in Task 2.1.2. (Existing Regulatory Model in Hawaii).

On July 10, 2018, the Hawaii PUC released a concept paper, *Goals and Outcomes for Performance-Based Regulation in Hawaii*, to support docket activities in the PBR Docket. To guide the PBR process, the PUC has adopted a conceptual framework where the PBR process would include identifying priorities and goals, assessing the current regulatory model and determining which regulatory mechanisms would drive utility performance. The process is summarized in **Error! Reference source not found.**.[62]

3.5.4 Potential PBR options for Hawaii

As discussed earlier, there are different mechanisms under PBR. This Study will analyze the costs and benefits of each regulatory model, so concrete PBR options need to be determined and evaluated. The Project Team proposes three PBR options for Hawaii, taking off from the goals of the Hawaii Ratepayer Protection Act, which "*directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels,*"[63] and PUC's aspirations of "*greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks and fulfillment of state policy goals,*"[64]. These three are Light PBR, Conventional PBR, and Outcomes-based PBR, which are discussed in detail below. The key components of each proposed PBR option are summarized in Figure 20.

The PBR regime in the succeeding regulatory periods would evolve and would be tailored to the specific environment and circumstances of the utilities. One of the lessons learned from other jurisdictions that have successfully implemented PBR is the need to adapt to changes when necessary. For instance, in the UK, the Office of Gas and Electricity Markets ("Ofgem") has routinely made modifications to the PBR regulations after each regulatory period to improve a particular mechanism that did not work as anticipated or to adapt to changes in the environment.

---

[61] Ibid. Page 9.

[62] Hawaii PUC. *Goals and Outcomes for Performance-Based Regulation in Hawaii*. July 10, 2018.

[63] HRS §269.

[64] PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation.* Docket No. 2018-0088. April 18, 2018. Page 52.

Figure 20. Key components of each proposed PBR option

	Status quo	Light PBR	Conventional PBR	Outcomes-Based PBR
Regulatory term	3 years	3 years	3 years	5 years
Rate-setting approach	Cost of Service	Cost of service	Revenue cap using indexing formula (e.g., inflation less productivity factor)	Revenue cap using building blocks approach
Performance incentives mechanisms	• Reliability (SAIDI and SAIFI) (penalty only) • Call center performance • Cost savings in renewable generation procurement (rewards and penalties) • Implementation of demand response portfolio (rewards only)	Expand current list to include metrics in the following categories: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Similar to Light PBR: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets	Based on the outcomes to be achieved, the PIM list is more comprehensive than Light and Conventional PBR: • Customer satisfaction • Service quality • Customer engagement • Availability • Reliability • Safety • Cost control • Asset management • Connection of renewable generation • Connection of DERs • RPS target • Demand response implementation • Competitive Procurement • Financial ratios
Earnings sharing mechanism ("ESM")	Asymmetrical ESM where customers will be credited: • 25% of share if the actual ROE is more than 1% of the authorized ROE • 50% of share if the actual ROE is over 2% than the authorized ROE • 90% of share if the actual ROE is over 3% of the authorized ROE	Similar to current ESM where customers share the excess earnings	ESM is symmetrical in terms of sharing percentages and deadbands. Deadbands are larger to reflect risks	Similar to conventional PBR where ESM is symmetrical
Treatment of capital and operating expenditures	Capex included in the rate base; O&M passed through	Similar to current approach	Total expenditure ("totex") approach	Totex approach

3.5.4.1 Option A: Light PBR

For Light PBR, the Project Team plans to build upon the existing regulatory model **and expand the current PIMs** to include other performance metrics, facilitating more effective achievement of the state's energy goals. This means that rates would be determined using the COS approach and there would be penalties and rewards for achieving or missing the targets. The expanded PIMs would work in conjunction with and would not replace all other current performance and customer service standards set by the PUC and any guaranteed minimum service levels standards. The regulatory term would be the same as the current general rate cycle of three (3) years. Finally, Light PBR would include the current ESM where above threshold earnings would be shared with the customers. Figure 21 lists the major features of Light PBR.

Figure 21. Key features of Light PBR

Light PBR	
Regulatory term	3 years
Rate-setting approach	Cost of service
Performance incentives mechanisms	Expand current list to include metrics in the following categories: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets
Earnings sharing mechanism ("ESM")	Similar to current ESM where customers share the excess earnings
Treatment of capital and operating expenditures	Similar to current approach

Regulatory term

As indicated above, the regulatory term under Light PBR would be the same as the **current three-year** general rate cycle.

Cost of service approach

Under Light PBR, the current rate-setting approach (in which the base rates are estimated from the target revenue requirement, which is the annual energy revenue approved by the PUC in the most recent test year general rate) [65] would still be used. This target revenue requirement would be calculated using the COS approach. For the succeeding two years of the regulatory term, the base rates would be adjusted using a per kWh rate adjustment (the "RBA Rate Adjustment"), which would be calculated by dividing a sum which includes the calendar year-end balance in the RBA balance as well as certain adjustments included in the Revenue Adjustment Mechanism ("RAM") and PIM provisions by the Company's forecast of MWh sales over the RBA Rate

[65] It should be noted that the target revenue excludes the following per the HECO Companies Revenue Balancing Account Provision: (i) revenue for fuel and purchased power expenses that are recovered either in the base rates or in a purchased power adjustment clause, (ii) revenue being separately tracked or recovered through any other surcharge or rate tracking mechanism, and (iii) applicable revenue taxes.

Adjustment recovery period.[66] Below is the formula of the rate under Light PBR. The PIMs and ESM will be discussed in the sections below.

$$(\text{PRICE})_{\text{Year2}} = (\text{PRICE})_{\text{Year1}} +/- \text{PIMs} +/-\text{RAM} - \text{ESM}$$

PIMs

As mentioned earlier, most of the HECO Companies' performance metrics are tracking-only metrics without associated rewards or penalties. There is only one PIM – call center performance – which has both rewards and penalties. The PIMs with penalties only are focused primarily on reliability (i.e., SAIFI and SAIDI). For PIMs with rewards only, the metrics are related to public policy goals such as renewables (procurement of renewable generation), DR (implementation of DR portfolio), and costs (cost savings). Under Light PBR, the current list of PIMs would be **expanded to include other categories such as** reliability, cost control, service quality, customer engagement, competitive procurement, and RPS achievement.

These additional categories would be in line with the goals of the Hawaii Ratepayer Protection Act, which states that

> *"in developing incentive and penalty mechanisms, the PUC's review of electric utility performance shall consider, but not be limited to, the following: (1) the economic incentives and cost-recovery mechanisms described in section 269-6(d); (2) volatility and affordability of electric rates and customer electric bills; (3) electric service reliability; (4) customer engagement and satisfaction, including customer options for managing electricity costs; (5) access to utility system information, including but not limited to public access to electric system planning data and aggregated customer energy use data and individual access to granular information about an individual customer's own energy use data; (6) rapid integration of renewable energy sources, including quality interconnection of customer-sited resources; and timely execution of competitive procurement, third-party interconnection, and other business processes."*[67]

Figure 22 shows some of the potential metrics under each of these categories.

In addition to expanding the list of the PIMs, Light PBR would also have **symmetrical PIMs** where the utilities' outstanding performance would be rewarded while poor performance would be penalized. As discussed earlier, the performance targets could be set by looking at the utilities' historical performance, benchmarking with comparables, or using appropriate statistical methods. The targets should also be valued by customers, can be objectively measured and independently audited. In setting the targets, the Commission should also consider the utilities'

---

[66] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf .

[67] SB2939. Ratepayer Protection Act.

historical performance, the inherent variability in performance data, and cost impact to achieve targets.

Figure 22. Potential metrics under each performance categories

Performance Categories	Performance measures
Availability	• Generation Availability • Equivalent Forced Outage Factor • Equivalent Forced Outage Factor Demand
Reliability	• SAIFI • SAIDI • No. of times that Power to a Customer is Interrupted
Cost control	• Cost of final delivered energy to Customers By Rate Class for Each Island System • Total Cost per Customer • Total Cost per Km of wires
Service Quality	• Telephone Calls Answered on Time • New Customer Connected on Time
Customer engagement	• No. of Consultations Conducted
Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
RPS targets	• Percentage of renewables relative to total energy • No. of Renewables Connected on Time

Rewards and penalties for PIMs are based on deviations from the performance targets. In theory, any formula which sets out penalties for missing performance targets should result in consequences high enough to deter poor performance and at least exceed the cost savings that the utility derives from not devoting resources into achieving targets. In the same manner, rewards should be significant enough to incentivize good performance, but also reflect consumer willingness to pay. In general, rewards and penalties are at times designed in a linear fashion. This means that the rewards and penalties are symmetrical. They also may be designed exponentially in which more substantial performance deviations from targets are rewarded or penalized disproportionately more than smaller performance deviations.

In implementing the PIMs, the Commission could either set a point estimate target or have an upper bound and a lower bound target for each PIM. In the former approach, the actual performance would be compared to the point estimate target to determine either an incentive or penalty. Meanwhile, if the actual performance is less than the lower bound target (in the latter method), a penalty would be imposed and vice versa. If actual performance lies between the lower and upper bound targets, no penalty or incentive would be levied.

Generally, there is a cap either for each potential fine (or reward) or a utility's maximum total exposure to performance standard rewards or penalties. Since PBR is relatively new in Hawaii, a cap on the annual financial exposure to the HECO Companies is recommended as a soft start. The cap could be increased as the Commission and HECO Companies acquire more experience with the PBR implementation. In some jurisdictions, the rewards and penalties are applied to the next regulatory period. The total incentives or penalties for each PIM are summed up to derive the total PIM payment at the end of the regulatory term. The total PIM payment would then be amortized, in present value terms, and added to or subtracted from the utility's revenue requirements of the succeeding regulatory period. An illustrative example of this approach is provided in Figure 23. Alternatively, the Commission could use the current approach of reflecting the rewards and penalties in the rates on the following t year.

Figure 23. Example of how to apply the rewards and penalties to the next regulatory period

	Regulatory period 1 (in $ millions) *Rewards or penalties based on performance relative to the target*				Regulatory period 2 (in $ millions) *Rewards or penalties based on performance relative to the target*			
	Year 1	Year 2	Year 3	Total	Year 1	Year 2	Year 3	Total
PIM 1	-	-	$ 2.00	$2.00				
PIM 2	($1.00)	($0.75)	($1.75)	($3.50)				
PIM 3	$5.00	$4.00	-	$9.00				
Total Rewards (Penalties)				$7.50				
Rewards added to the annual revenue requirements					$2.50	$2.50	$2.50	$7.50

Under Light PBR, there would be **active monitoring of performance against set targets**. The utilities would be expected to submit quarterly reports[68] on their performance to the Commission, all of which should also be posted on the utilities' websites.

ESM

The enhanced PIMs would also be coupled with the same **ESM** as the current one where only above threshold earnings are shared with the customers. More specific examples of calculations of customer rebates/credits based on ROE (under the current ESM structure) are shown below:

- If HECO Companies' actual ROE is more than 100 basis points or 1% over the authorized ROE, customers will be credited with a 25% share.
- If the actual ROE is more than 200 basis points or 2% over the allowed ROE, the customers will get a 50% share.
- If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers get a 90% share.

[68] Currently, HECO Companies are required to submit their PIM data on a quarterly basis.

Light PBR would be easier to implement, given the timeline provided by the legislation (where PBR needs to be applied by January 1, 2020), compared with the other two PBR models discussed below.

However, as discussed earlier, each performance metric requires a reasonable target which relies on available data, either from the HECO Companies or comparable peers. Implementation of each performance metric also requires certain expenditures from utilities, eventually causing an increase in rates. Selecting practical PIMs, precise targets, together with appropriate ESM is critical to the success of this approach.

3.5.4.2 Option B: Conventional PBR

A revenue cap would be used to determine the revenues and rates during the PBR term under the Conventional PBR. The expanded list of PIMs and the reporting requirements would also be the same as in Light PBR. There would also be an ESM; however, the deadband would be larger and the sharing and deadband symmetrical. The total expenditure ("totex") approach would also be utilized under this option.

Figure 24. Key features of Conventional PBR option

	Conventional PBR
Regulatory term	3 years
Rate-setting approach	Revenue cap using indexing formula (e.g., inflation less productivity factor)
Performance incentives mechanisms	Similar to Light PBR: • Availability • Reliability • Cost control • Service quality • Customer engagement • Competitive procurement • RPS targets
Earnings sharing mechanism ("ESM")	ESM is symmetrical in terms of sharing percentages and deadbands. Deadbands are larger to reflect risks.
Treatment of capital and operating expenditures	Total expenditure ("totex") approach

Regulatory term

Conventional PBR would also have a three-year term as in the case of Light PBR.

Revenue cap

Unlike Light PBR, Conventional PBR would have a **rate cap**. As discussed in Section 0, a rate cap can either be a price or revenue cap. One is not necessarily better than the other, but the suitability of the rate cap would depend on how it aligns with the goals and needs of the State. Given the increasing availability of customer-sited, distributed generation and flat or declining forecasted demand in the State, a revenue cap would be a better option for the State. Indeed, a revenue cap would be more compatible than a price cap for Hawaii—with its policies encouraging conservation, demand response programs or energy efficiency—because it removes the conflict between regulation and policy goals to a significant degree. A revenue cap also allows for more pricing flexibility and is preferable when costs do not vary significantly with sales volumes or when volume changes are less predictable. Furthermore, a revenue cap (as in the case of a price cap) would incentivize utilities to minimize overall costs as revenues are fixed, and they could generate more profits by operating more efficiently and spending prudently. As mentioned earlier, Hawaii currently uses the revenue cap as part of the decoupling mechanism.

Under Conventional PBR, the utilities would determine the going-in rates for the first year of implementation, subject to approval by the PUC. As discussed earlier, the going-in rates are the basis to which the PBR formula is applied. Going-in rates are determined through the COS calculation and estimated independently from the PBR formula. The going-in rates would depend on the revenue requirements needed by utilities in serving their customers and operating profitably. Since the Project Team is proposing a revenue cap, the revenue requirements for the succeeding years (year 2 and 3 of the PBR term) would be adjusted based on an indexing formula that takes changes in inflation and productivity into account. More specifically, the formula is shown below:

$$(\text{REVENUE})_{\text{YearT}} = (\text{REVENUE}_{\text{YearT-0}}) * [1+(\text{inflation} - \text{productivity factor})] +/- \text{PIMs} +/- \text{RAM} +/- \text{ESM}$$

The inflation provides a mechanism through which the utility's revenues may be adjusted annually to reflect expected input cost increases. On the other hand, the productivity factor is the rate of change in efficiency that is expected or targeted. There is an expectation that if the utility achieves the productivity factor, then it would be able to earn its allowed rate of return. The productivity factor also serves as the mechanism by which customers reap the rewards of PBR (as it dictates the pace of real rate reductions).

A balancing account mechanism would be needed to capture the difference between the approved revenue requirements and the actual revenues.

Total expenditure approach

To address the PUC's objective of having a mechanism that results in *"efficient investment and allocation of resources regardless of classification as capital or operating expenses,"*[69] the totex approach, like in the UK's RIIO model, would be incorporated in the

[69] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

Conventional PBR. The concept of totex started in UK and was utilized to address the perceived utility bias towards capital expenditure ("capex") solutions.

RIIO's totex approach

Under the RIIO's totex approach, the utilities are incentivized to consider the whole life costs, rather than being driven to choose between capex and opex. A capitalization ratio is set between opex and capex that would be applied in the regulatory period. This ratio sets how much revenue will be expensed ("fast money") or added to the regulatory asset base ("slow money") at the onset of the regulatory period. By doing this, the utilities would be indifferent on whether to use opex or capex knowing that their decisions would not impact how the allowed revenue is determined.

Through the totex approach, utilities are incentivized to submit reasonable forecasts and to spend the allowance prudently. Utilities that submit forecasts that are closer to Ofgem's view of efficient costs, receive a higher totex incentive rate. This means that the utilities receive more of the underspend. Utilities that underspend get to keep the underspent amount. Ofgem expects that efficient spending leads to better returns for the investors and lower rates for customers.

Utilities need to report their actual totex to the regulator annually, explaining the actual performance compared to the allowed totex. According to the 2016-2017 Annual Report, the distribution utilities in UK have underspent their totex allowance by 7% or £531 million for the 2016-2017 period. According to Ofgem, a proportion of the underspend is due to efficiencies, which have effect of driving down the costs.

Sources: Ofgem. RIIO-ED1 Annual Report 2016-17 and Ofgem. RIIO Handbook.

Under a totex approach, there is no distinction between capital and operating expenditures. In this way, the utilities would be expected to use the most cost-effective solution. For instance, the utility would be encouraged to perform maintenance to avoid replacing an asset or use demand-side management to avoid building new capacity. The totex approach would also remove the incentive for utilities to reclassify costs from operating expenditure ("opex") to capex. In addition, it will also eliminate the issue of determining the boundaries between opex and capex, which entails a significant amount of time to perform and regulatory costs. The textbox below provides a brief overview of how the totex approach works in the UK.

PIMs

The same list of enhanced PIMs as well as reporting requirements would be included under Conventional PBR.

ESM

There would also be an **ESM** under Conventional PBR, although larger and symmetrical deadband and sharing percentages would be adopted. This means that the percentage share between the utility and the consumers would be the same (e.g., 50% for utility and 50% for customers) and that the deadband for gains and losses would be the same (e.g., +/- 200 basis points). The reason for having a larger deadband under this model is to provide the utilities the opportunity to earn more given the higher risk of the indexing formula in determining the rates. Including the ESM would align with the PUC's aim of having a mechanism that results in *"fair distribution of risks between utilities and customers."*[70]

3.5.4.3 Option C: Outcomes-based PBR

The third potential PBR option for Hawaii is Outcomes-based PBR, which is similar to the UK's RIIO model. Under this model, the **focus would be on setting the outcomes** (and incentives to deliver the outputs) by providing utilities the flexibility in producing the results (and determining inputs needed in achieving them). Revenues (and rates) would be forecasted for the next five (5) years using a building blocks approach.

Figure 25. Key features of Outcomes-based PBR

Outcomes-Based PBR	
Regulatory term	5 years
Rate-setting approach	Revenue cap using building blocks approach
Performance incentives mechanisms	Based on the outcomes to be achieved, the PIM list is more comprehensive than Light and Conventional PBR: • Customer satisfaction • Service quality • Customer engagement • Availability • Reliability • Safety • Cost control • Asset management • Connection of renewable generation • Connection of DERs • RPS target • Demand response implementation • Competitive Procurement • Financial Ratios
Earnings sharing mechanism ("ESM")	Similar to conventional PBR where ESM is symmetrical
Treatment of capital and operating expenditures	Totex approach

[70] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018. Page 52.

Regulatory term

A **longer regulatory period (preferably five years)** would be more appropriate under Outcomes-based PBR to better align the setting of the rates and the planning horizon of the utilities. This extended term would also strengthen efficiency incentives and help manage the pace of rate increases for customers through adjustments that are calculated to smooth the impact of forecasted expenditures. Also, the longer period can motivate the utilities to adopt performance improvements and cost reductions further because the longer term would allow them to retain increased profits. Moreover, it would reduce regulatory costs and burden of filing another PBR plan only after a short period.

Outcomes and PIMs

Outcomes-based PBR has four (4) output categories, namely:

(i) **enhance customer experience**: provision of services in a manner that enriches customer service

(ii) **improve utility performance**: continuous enhancement in productivity, attainment of cost performance, and improved delivery on system availability, reliability, and quality objectives

(iii) **achieve public policies and goals**: compliance of utilities to obligations in legislation and regulatory requirements

(iv) **attain healthy financial performance**: maintenance of financial viability and sustained savings from operational efficiency.

Based on these outcomes, the performance categories and measures for each group would be determined. Figure 26 shows some examples of PIMs for each category. Unlike Light PBR, Outcomes-based PBR would require a more comprehensive list of PIMs. The Commission would need to have a **rigorous performance reporting and monitoring process** to determine if the expected outcomes are being achieved.

Under Outcomes-based PBR, the HECO Companies would be required to develop a **robust business plan** that sets out what they intend to deliver and achieve during the regulatory period. The plan should include target revenues from existing and future customers to ensure the achievement of outcomes. It would also provide evidence of the utility's cost and revenue forecasts and detailed investment plans for the regulatory period.

Furthermore, the HECO Companies would be expected to file **capital and asset management plans** to support their rate application. They would need to provide evidence that their planning and prioritization process is rigorous to justify the proposed capital budget. In particular, the plan should be able to explain how utilities sought to control costs in relation to its proposed investments, for example, through appropriate optimization and prioritization of investment expenditure. Utilities should also establish that the plans benefited from meaningful consultation with customers and stakeholders. The Commission would be expected to monitor capital spending against the approved plans by requiring utilities to report annually on actual amounts spent. A large disparity between actual expenditures from those reflected in the plans could trigger a Commission investigation.

Figure 26. Indicative outcomes and potential performance categories and indicators in Outcomes-based PBR

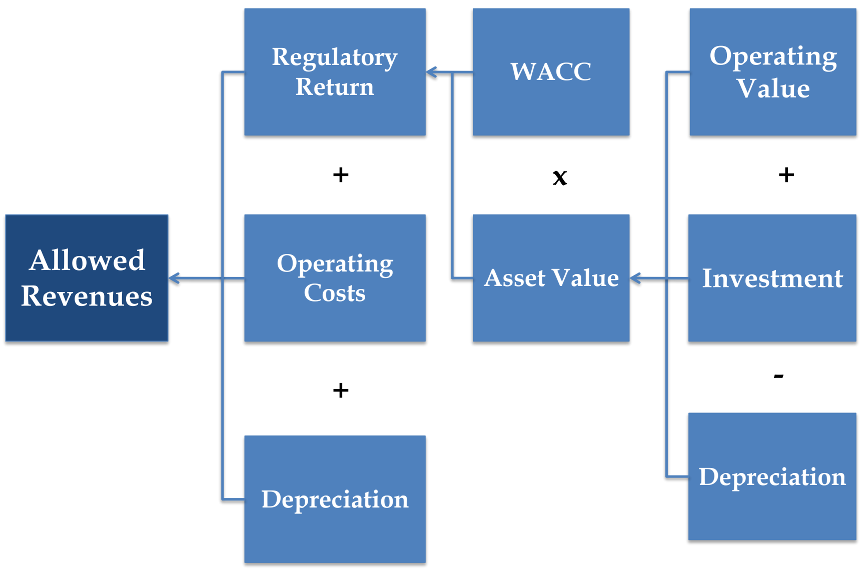
Performance Outcome	Performance Categories	Performance measures
Enhance customer experience	Customer satisfaction	• Billing accuracy • First contact resolution
	Service quality	• Telephone calls answered on time • New customer connected on time
	Customer engagement	• No. of Consultations Conducted
	Availability	• Generation availability • Equivalent Forced Outage Factor • Equivalent Forced Outage Factor Demand
Improve utility performance	Reliability	• SAIFI • SAIDI • No. of times that power to a customer is interrupted
	Safety	• Number of general public incidents
	Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
	Asset management	• Transmission plan implementation progress • Distribution plan implementation progress
Achieve public policies and goals	Connection of renewable generation	• No. of renewables connected on time
	Connection of DERs	• No. of DERs connected on time
	RPS target	• Percentage of renewables relative to total energy
	Demand response implementation	• Amount of demand response implemented
	Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
Attain financial performance	Financial ratios	• Leverage: Total Debt to Equity ratio • Liquidity: Current Ratio (Current Assets/ Current Liabilities)

Revenue cap using building blocks approach

Similar to Conventional PBR, a revenue cap mechanism would be used in this model to align with the public policies and energy goals of the State. In contrast to Conventional PBR, however, Outcomes-based PBR would have **rates that are set based on a five-year forecast** of the utilities' revenue requirement and sales volumes. This means that unlike Conventional PBR where the rate for the next two years of the regulatory period will increase by an indexing formula,[71] Outcomes-based PBR would already determine the revenue requirements and the rates for the next five years based on the utilities' revenue and sales forecasts.

Generally, a building blocks approach is used to forecast the revenues. This approach requires a forecast of total costs (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory term. The forecast considers productivity improvements and targets and necessary capital investment. These total costs would then be added together – hence, "built up" – to an allowed revenue requirement for the utilities based on estimates of the utilities' expected capital and operating costs and return of and return on asset base. Figure 27 shows how the allowed revenues are built up.

Figure 27. "Building up" allowed revenues under the building blocks model



The Commission would assess the proposed costs using historical performance metrics, benchmarks of unit costs, and industry-wide benchmarks (including industry total factor productivity studies). For example, regulators and utilities in Australia and the UK usually commission independent expert reports to assess the proposed expenditures that make up the forecast revenue requirements of each utility.

ESM and totex approach

[71] First year rate of the regulatory term is the going-in rate which is determined through a cost of service as discussed in

Figure 16. The rates for the second and third year are based on the indexing formula, which is based on the increase in inflation less approved productivity factor.

Finally, similar to the Conventional PBR, the symmetrical ESM and totex approach would also be incorporated in this option. See discussion Section 3.5.4.2 for the discussion on these mechanisms.

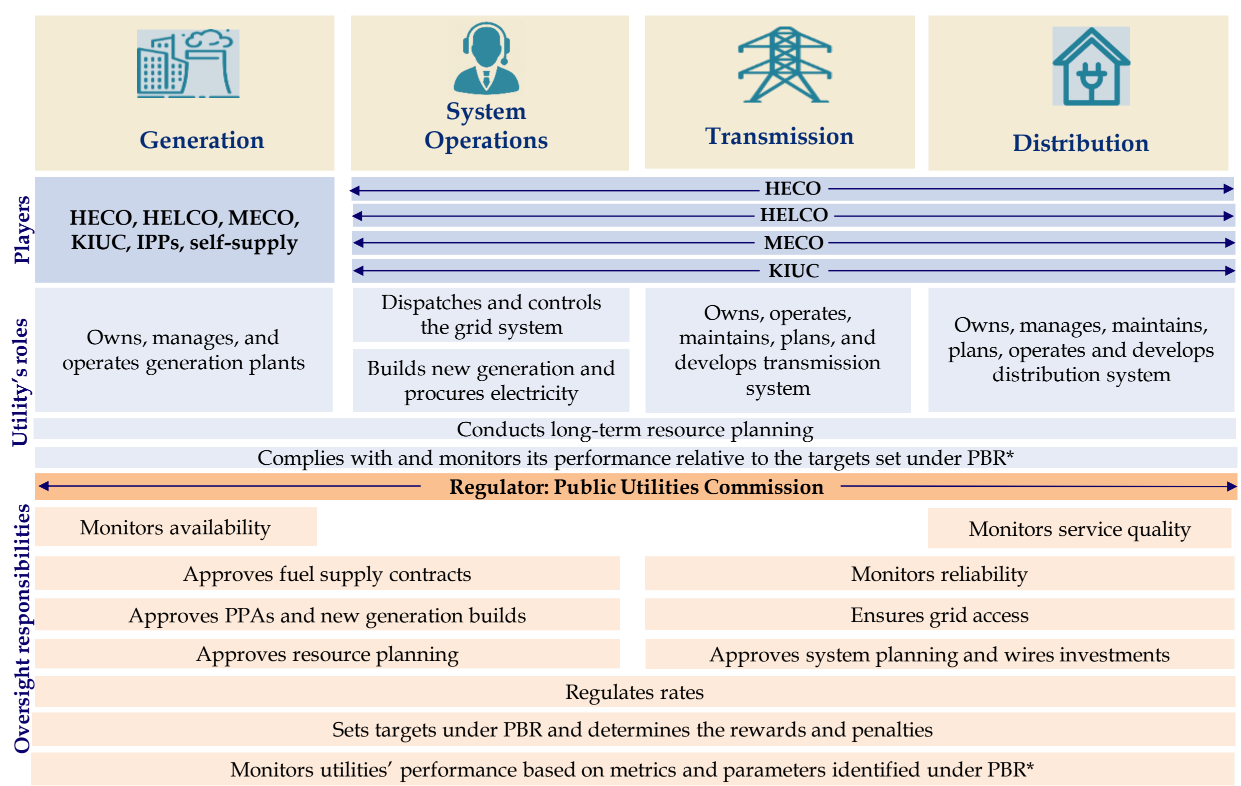
3.5.5 Oversight under PBR

The ownership model under a PBR model would remain the same where the incumbent vertically-integrated utilities would still own and operate the generation, transmission, and distribution assets. The PUC would administer the implementation of the PBR. These PBR oversight tasks would include:

- reviewing the PBR plan that the utilities will submit;
- identifying the performance indicators that will be used to measure the following: (i) cost control, (ii) efficient investment, (iii) "rapid" integration of renewables, and (iv) timely execution of competitive procurement;
- determining the targets that the utilities need to achieve for each metric identified above;
- setting up the rewards and penalties for attaining or missing the targets; and
- monitoring the actual performance of the utilities relative to the targets.

Figure 28 shows the graphical depiction of PUC's oversight under PBR.

Figure 28. Graphical depiction of the value chain under a PBR model



Note: *Except for KIUC

3.6 Lighter regulation for KIUC

Since KIUC is exempt from the PBR docket, the Project Team evaluated a separate regulatory model for KIUC – one with lighter PUC oversight compared to the status quo. Currently, KIUC is under the regulation of PUC (mostly similar to HECO Companies).

Despite a lighter oversight, KIUC would also need to meet specific metrics to remain in compliance with the Rural Utilities Services ("RUS") because it receives subsidized financing from the latter. The additional regulation from the PUC could be more targeted for the co-op business model, owing to its governance structure with direct accountability to its customer-members and RUS oversight. PUC's regulation on co-ops varies depending on jurisdictions. Reflecting the unique character of cooperatives as consumer-owned utilities, PUCs do not regulate tariffs in 31 of the 47 states in the US that have electric co-ops.[72]

As stated in the *2016 - 2030 strategy plan*, KIUC "*began to consider moving out from under the authority of the PUC to a deregulated or minimally regulated status, which would allow us greater flexibility in responding to member concerns and unexpected changes in fuel prices and market conditions.*"[73] As part of the "*strategic goals and actions*," KIUC will "*consider and potentially seek increased exemption from regulation by the PUC through changes in State law or PUC order.*"[74] Hawaii Revised Statutes § 269-31 states that "*the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric cooperative in determining the scope and need for any regulatory oversight or requirements over such electric cooperative.*"[75]

Under a lighter regulation model, regulations would be relaxed for KIUC. KIUC would be exempted from PUC regulations such as approval of rate setting and design, power purchase agreements with independent power agreements, fuel contracts and large capex, if such transactions or activities would not exceed particular thresholds. KIUC's Board of Directors would continue to approve operating and capital budget, develop resource plans (that take the interest of the members into account), and ensure adequacy of electricity. Nevertheless, KIUC will still be required to meet the State's energy goals.

Aside from the Board of Directors, KIUC's corporate leadership would remain accountable to the following entities:

- *KIUC members*: annual meeting of members is held for reviewing the financial progress of the KIUC for the prior calendar year, and transacting any other business as may be

[72] USAID and NRECA International. *Guides for Electric Cooperative Development and Rural Electrification*. Page 8.

[73] KIUC. *Strategic Plan Update 2016 – 2030.* January 31, 2017 adopted. Page 4.

[74] Ibid. Page 5.

[75] HRS § 269-31.

designated in the notice of the meeting.[76] Also, special meetings of members may be called by (i) the Board of Directors, (ii) the Chairman, or (iii) 5% of all members or 250 members, whichever is less. Except for any motion, resolution or amendment for which a recorded vote is authorized, 5% of the members shall constitute a quorum necessary to the transaction of business to be voted on by the members at any annual or special meeting of the members.[77] Each member has one vote upon each matter submitted to a vote at a meeting of the members.[78]

- *RUS*: KIUC receives low-cost financing from RUS, allowing it to pass the lower cost of capital to consumers. However, these loans have covenants regarding coverage ratios and capital requirements that KIUC is obligated to meet to maintain its access to low-cost capital.[79] In addition, KIUC also submits its construction plans to RUS for review and approval.[80]

An indicative approach to light-handed co-op regulation includes, but is not limited to:

- annual timely filing of financial and performance metric documents;
- KIUC compliance with State policies unless there are explicit exemptions;
- seeking of approval if KIUC wishes to pay a salary higher than HECO Companies for any similar position;
- the opening of PUC investigation in the following events (or similar cases):
    - when rate increases exceed the higher of 5% or 2 times the State Consumer Price Index, and 5[x] or more ratepayers object to PUC, PUC may open an investigation;
    - when the capex spent increases beyond the set threshold;
    - if ratepayers provide evidence of rate discrimination; and

[76] KIUC. *Seventh Revised and Restated By-laws of KIUC - Meetings of Members and Voting*. Website. Access Date: July 11, 2018. Website. <http://website.kiuc.coop/content/bylaws>

[77] Ibid, Section 5 - Quorum.

[78] Ibid, Section 4 – Voting.

[79] KIUC. Board Policy No. 29. Equity Management Planning. March 24, 2015. Page 4. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/bp/BP29-rev2015-0324-%20EMP.pdf>

[80] KIUC. Regular Meeting of the Board of Directors on September 27, 2016. Minutes. Page 19. <http://website.kiuc.coop/sites/kiuc/files/PDF/minutes/minutes-2016-0927-DRAFT.pdf>

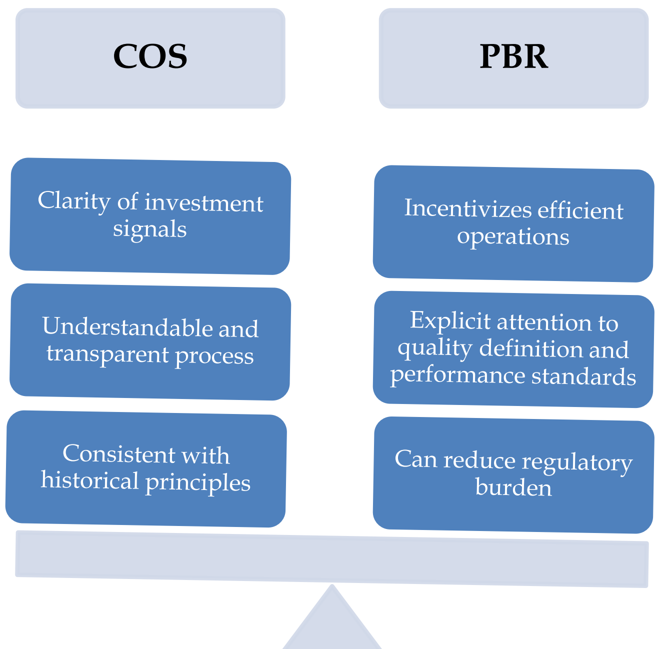
- if the customer has exhausted KIUC internal dispute resolution processes and continues to feel KIUC has acted contrary to their policies, PUC guidelines, or the State law.

4 Appendix A: PBR design

4.1 COS and PBR

Under a PBR regulatory approach, COS analysis and COS ratemaking principles continue to be significant. COS elements are vital inputs to PBR regulation: PBR regimes begin with a COS-based analysis of what the "going-in" rates should be. Moreover, COS principles, such as the opportunity for full cost recovery and commercially reasonable return on equity ("ROE") targets, are still important tenets under PBR. Although under the harder forms of PBR, the annual revenue requirement and rate base calculations do not directly figure into the rates, a COS analysis is required at the end of each generation for PBR, known as the "re-basing" review, which serves as the basis for "going in" rates.

Figure 29. COS versus PBR



4.2 Price cap vs. revenue cap

Under a price cap, which is also called price indexing or rate indexing, the regulator approves a formula that determines how fast rates can increase. The regulator sets an initial price $(\text{PRICE})_{\text{Year1}}$ and the rates are adjusted for each year considering changes in inflation and productivity (or X-factor). The inflation factor, which is driven by macroeconomic forces that are beyond the control of the utilities' management, is passed on to customers. The productivity or X-factor, on the other hand, is the rate of change in efficiency that is expected or targeted. There is a presumption that if the utilities achieve the productivity factor, then they will be able to earn its allowed rate of return. The productivity factor also serves as the mechanism by which customers reap the rewards of PBR as it dictates the pace of real rate reductions.

Price caps are usually applied to any of the following: the utilities' average price, the average prices for each customer class, or to each rate element of each rate schedule. This provides the utilities a degree of flexibility in how to optimize specific customer rates and consider cost allocations.

Price caps have several advantages. First, price caps provide incentives for cost efficiency and cost reduction.[81] The cost-reducing incentives of price caps are relatively stable and viable because they can hold over an extended period and they have built-in adjustments (I - X) that do not endanger the utilities' finances.[82] Second, regulators under price caps do not need detailed information about the utilities' cost functions to calibrate the price cap parameters.[83] Third, utilities under a weighted average price cap approach have the flexibility to change relative prices in the regulated basket of services. The use of baskets has *"provided utility[ies] with the ability and incentive to rebalance their prices in the direction of allocatively superior prices and has allowed regulated utilities to compete with new entrants."*[84] Finally, price caps could provide incentives for utilities to meet and expand demand because revenues are not capped as they would be under a revenue cap approach. Utilities will have an incentive to increase sales if the marginal revenue accompanying the increased service provision is higher than the marginal cost of increased service provision. However, this contradicts demand management plans where energy savings and energy efficiencies are encouraged.

On the other hand, as mentioned earlier, the **revenue cap** regulates the maximum allowable revenue that a utility can earn. Under a revenue cap, revenue requirement in a given year is established according to the previous year's revenue requirement and adjusted based on a predetermined formula, considering changes in inflation and productivity.

Under a revenue cap, there is no incentive for utilities to maximize sales but there is still an incentive to minimize overall costs (i.e., with revenues fixed, profits increase if costs are cut), making it arguably more compatible with utilities (like those in Hawaii) that are facing substantial demand response programs or energy efficiency reductions in consumer demand. Moreover, with a revenue cap, utilities are generally exposed to lower levels of risk related to changes in demand or sales.[85] Revenue cap regimes provide more pricing flexibility and are preferable when costs do not vary significantly with sales volumes. Finally, the ability to make additional profits

[81] Lantz, Björn. "Hybrid Revenue Caps and Incentive Regulation." *Energy Economics* 30 (2008): 688-695. September 25, 2006. Page 688-694.

[82] Vogelsang, Ingo. "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective." *Journal of Regulatory Economics* 22:1 (2002): 5-27. Page 8.

[83] Ibid.

[84] Ibid.

[85] National Association of Regulatory Utility Commissioners. *Performance-Based Regulation for Distribution Utilities*. December 2000. Page 23.

due to increased scale is removed under a revenue cap regime, along with any means to adjust revenue if costs increase with volumes.

Price cap and revenue cap regimes could converge if various true-up mechanisms are deployed. Price caps often incorporate measures to protect utilities and customers against weather and economic growth-related volume fluctuations. Revenue caps might contain adjusters if utilities' experiences sustained and unexpected volume increases that require additional capital expenditure.

4.3 Approach to designing rate cap

There are generally two approaches for rate-setting under a price cap regime: (i) **total factor productivity ("TFP") based I-X approach;[86] and (ii) the building blocks approach.**

The **TFP-based I-X approach** was developed as a relatively simple mechanistic, yet empirically "rich," approach to adjusting rate caps and providing incentives. The primary view that grounds most TFP-based applications of PBR models is that firms should be able to improve productivity consistent with measured long-term productivity improvements (historically) for the industry. In North America, the TFP-based approach to an I-X rate cap is generally used.[87]

Under the TFP-based I-X approach, prices for the forthcoming regulatory period are set in relation to a historical productivity trend, which is usually obtained from a statistical study of a group of comparator firms. The price that the utilities can charge is fixed in advance for a certain period, and price may increase by no more than the inflation less the X-factor.

This approach is suited for utilities facing steady state of operating and capital investment profile as it provides for a reasonably stable rate of change in the price or revenue cap because the I factor is generally not volatile and the X-factor is often fixed. Under steady state conditions, economists expect typically the utility sector to be able to gradually improve its productivity over time – driven by any or all of the following: technological change, allocative efficiency, improved capacity utilization, economies of scale, or elimination of efficiencies. However, from time to time, to the extent that the pace with which the utilities are making investments in capital and deploying labor exceeds the speed of demand and customer growth, then the rate of change in productivity will take on a negative value. Furthermore, revenue requirements and adjustment parameters are often related to historical studies in which regulators determine parameters for the IR plan; these studies may have limited relationship to or fail to predict future trends.

The **building blocks approach,** on the other hand, has been the cornerstone of PBR in Australia and the UK for over 20 years now. First introduced in the early 1990s in the UK, the building blocks approach was developed to derive the components of the price cap regime (RPI-X) that

---

[86] TFP-based I-X approach is not the only option. Other options include but not limited to retail price index or consumer price index minus a productivity factor ("X").

[87] For example, most of the PBR pioneers in the US, i.e., California, Maine, and Massachusetts used the TFP-based approach in 1990s. Source: *Discussion Paper on Rate Regulation in Ontario*. Website. <http://cf.oeb.ca/documents/consultatation_ontariogasmarket_rateregulation_070904.pdf.>

the regulator wanted to apply to newly privatized, monopoly industries, commencing with telecommunications, and then expanding to other network industries in gas and electricity.

Under this approach, a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory control period (i.e., PBR term). The forecast considers productivity improvements and targets and necessary capital investment. After this procedure, these total costs are added together - "built up"- to an allowed revenue requirement for a utility based on estimates of the utility's expected capital and operating costs and return of and return on asset base.

The revenue requirement is then translated into a starting price (for the price or revenue cap) referred to as P_0 and an annual rate of change is estimated over the term of the PBR plan to adjust the price cap/revenue cap. The annual adjustment is referred to as I-X in Australia and RPI-X in the UK. The I-factor is the inflation adjustment. Meanwhile, the estimated X-factor reflects both the productivity target and the real price change required to support a utility's revenue requirement. This reference to an X-factor can be confusing in the North American context because it is not solely a measure of productivity but reflects an aggregated view of efficiency trends across total costs and the need for efficient capital investment and (potentially) rate smoothing.

One of the most significant challenges associated with the building blocks approach is the reliance on forecasts. Related to this challenge is the difficulty on the side of the regulators to gather complete information about the costs of each utility; this weakens their ability to estimate the actual level of the utilities' efficient costs. The utility may use this advantage during the regulatory review process to try to increase its profits. This could result in higher costs and prices, which could be set above the level indicative of efficient costs.[88]

[88] London Economics International. "Literature review: regulatory economics and performance-based ratemaking." Nova Scotia Department of Energy and Mines. Web. <https://energy.novascotia.ca/sites/default/files/files/Literature%20Review%20-%20LEI%20Consolidated.pdf>

5 Appendix B: Scope of work to which this deliverable responds

Task 2.1.1 Summary comparison of Regulatory Models from Hawaii's perspective, including a graphical depiction of each regulatory model and comparison.

CONTRACTOR shall provide a brief narrative introduction of each regulatory model.

DELIVERABLE FOR TASK 2.1.1. CONTRACTOR shall provide its conclusions and all work related to providing an initial narrative introduction of each potential regulatory model that Hawaii could consider, including, but not limited to: status quo, status quo with increased oversight, distribution focused regulatory model (REV), and performance-based regulation model. CONTRACTOR shall provide results of discussions with DBEDT and other stakeholders about key priorities of a regulatory model. CONTRACTOR shall also provide information on how each model operates and how the oversight of the different components of the electric power value chain is managed. The deliverable shall be an MS Word document which summarizes the above, includes an intuitive graphical depiction of each regulatory model and comparison, and a list of potentially relevant jurisdictions that use each of the regulatory models. CONTRACTOR shall submit deliverable for TASK 2.1.1 to the STATE for approval.

6 Appendix C: List of works consulted

Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237. September 12, 2012.

EIA. *Today in Energy*. Website. Access Date: March 22, 2018. <https://www.eia.gov/todayinenergy/detail.php?id=790>.

ERCOT. *Company profile - History.* Website. <http://www.ercot.com/about/profile/history>. Access Date: April 2, 2018.

FERC. Regional Transmission Organizations (Issued December 20, 1999) (Docket No. RM99-2-000; Order No. 2000), page 151.

Frayer, Julia, Neil Bush, Guilain Cals, and Ma. Cherrylin Trinidad. "Performance Based Rate Making in Canada: Current Practice, Key Principles and Lessons Learned in Forming a Regulatory Regime." Submitted to the Canadian Electricity Association. June 2011.

Guernsey. *County of Maui: Analysis of Alternative Forms of Ownership and Alternative Business Models for Maui County's Electric Utility Company*. December 23, 2015.

Hawaii House Bill 2525. 2012.

Hawaii Revised Statutes ("HRS") Chapter 269 – Public Utilities Commission

Hawaii State Energy Office. State of Hawaii – Energy Policy Directives. Website. Access Date: March 2, 2018. <http://energy.hawaii.gov/energypolicy>

Joskow. *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks.* NBER. August 15, 2007.

Lantz, Björn. "Hybrid Revenue Caps and Incentive Regulation." *Energy Economics* 30 (2008) 688-695. September 25, 2006.

Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui*. August 25, 2017.

National Association of Regulatory Utility Commissioners. *Performance-Based Regulation for Distribution Utilities*. December 2000.

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding (issued and effective April 25, 2014).

Ofgem. *Regulating Energy Networks for the Future: RPI-X@20 Emerging Thinking*. London: Ofgem, 2010.

Ofgem. *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*. London: Ofgem, 2010.

Ofgem. *Electricity Distribution Price Control Review Final Proposals*. December 7, 2009.

Ofgem. *Emerging Thinking (Appendix 3)*. London: Ofgem, 2010.

Sappington, David et al. *The State of Performance-Based Regulation in the U.S. Electric Utility Industry*. Elsevier Science Inc., 1040-6190/01, 2002.

Vogelsang, Ingo. "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective." *Journal of Regulatory Economics* 22.1 (2002): 5-27.

High-level and general assessment of the existing regulatory model in place in Hawaii

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

May 30, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that evaluates the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which corresponds to Task 2.1.2., is one of several working papers associated with that engagement. This paper provides a general assessment of the existing regulatory model in place in Hawaii. Electric utilities in Hawaii are regulated by the Public Utilities Commission while the Hawaii State Energy Office assists in developing and implementing the policies as mandated by the legislature. Generally, electricity rates for the HECO Companies are determined through a cost of service ("COS") approach with some variations and includes components associated with performance-based regulation such as the earning sharing mechanisms, penalties for not achieving certain performance standards (but mostly in reliability), decoupling and multi-year rate plan, while rates for the KIUC are determined using the Times Interest Earned Ratio ("TIER") level. The strengths of the current regulatory model include PUC's independence and innovativeness, participatory regulatory process, the regulatory model allows rates to be set to allow utilities a reasonable rate of return, and policies are in place to achieve diversifying the state's energy portfolio. Areas for improvements include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, reducing complexity and cost of regulation and regulatory compliance and mitigate risks in the establishment of the final design of the Performance-Based Regulation ("PBR").

Table of Contents

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Cherrylin Trinidad/Tianying Lan
617-933-7229
cherrylin@londoneconomics.com

Table of Figures

List of acronyms

CGS	Customer Grid-Supply
CGS +	Customer Grid-Supply Plus
COS	Cost of Service
CSS	Customer Self-Supply
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Hawaii Division of Consumer Advocacy
EIA	US Energy Information Administration
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IOU	Investor-owned utility
IPPs	Independent power producers
IRS	Interconnection requirements study
ISO	Independent system operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
NEM	Net energy metering
NERC	North American Electric Reliability Corporation
PBR	Performance-based regulation
PIMs	Performance incentive mechanisms
PUC	Public Utilities Commission
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account

ROE	Return on Equity
RPS	Renewable portfolio standards
RSWG	Reliability Standards Working Group
RTO	Regional transmission organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that evaluates the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.1.2 in the project scope of work, provides an overview and general assessment of the existing regulatory model in Hawaii.

Each of the counties in Hawaii is served by a vertically integrated utility: Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), Maui Electric Company, Ltd. ("MECO"),[1] and Kauai Island Utility Cooperative ("KIUC").[2] These utilities are also the major generators in their respective counties as well as the owners and operators of the transmission and distribution assets in their respective service areas. Generation in the State is also provided by several independent power producers ("IPP") as well as customer-sited and/or owned distributed generation ("DG").

The electric utilities in the State are regulated by the Public Utilities Commission of the State of Hawaii ("PUC"). More specifically, the PUC:

- regulates public utilities' rates, terms and conditions of service, performance, and compliance with laws and regulations;
- reviews applications for approval to construct transmission lines, to make large capital expenditures, to issue stocks and bonds, notes and other evidence of debt;
- reviews purchases, acquisitions, sales, or other disposition of utility assets, including mergers and acquisitions involving the utility company;
- oversees and monitors the electric reliability, utility's service, operations (*e.g.*, safety), and resource planning;
- initiates and conducts investigative proceedings;
- provides guidelines on various standards and regulations such as interconnection standards, procurement of generation, and performance-based regulation ("PBR") to name a few;
- implements state policy;

---

[1] As mentioned in Task 1.1.3., Kalawao County is a judicial district of Maui County and has limited electricity system facilities. For discussion purposes, Kalawao is included under the County of Maui.

[2] HELCO and MECO are subsidiaries of HECO; HECO, HELCO, and MECO will be collectively referred to as the "HECO Companies.")

- develops and adopts administrative rules in administrative rulemaking proceedings; and
- generally enforces public utility laws and regulations.

The State government (Legislature and Governor) establishes the energy policies, legislative enactments, and resolutions that are further developed, implemented and enforced by the PUC. The Hawaii State Energy Office ("HSEO"), within the Department of Business Economic Development & Tourism ("DBEDT"), assists in developing and implementing energy policy as may be provided by the State. The roles and responsibilities of the PUC and the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs ("Consumer Advocate") are discussed in Section 3.2.

Recently, Governor David Ige signed into law the Ratepayer Protection Act.[3] The new law orders the PUC to create "performance incentives and penalty mechanisms" by January 1, 2020, that break the direct link between allowed electric utilities' revenues and investment levels. Related to the Ratepayer Protection Act, the PUC initiated a proceeding to Investigate Performance-Based Regulation, on April 18, 2018.[4] The PUC stated in Order 35411 that they are interested in PBR mechanisms that result in greater cost control and reduced rate volatility, efficient investment and allocation of resources regardless of classification as capital or operating expenses, fair distribution of risks between utilities and customers, and fulfillment of state policy goals.[5] This investigative proceeding only applies to the HECO Companies and not to KIUC, a cooperative in Hawaii.[6] This will be discussed in Section 3.5.

Electricity rates for the HECO Companies are generally determined through a cost of service ("COS") (sometimes referred to as "rate return regulation") approach with some components associated with performance-based regulation such as the earning sharing mechanisms ("ESM"), penalties for not achieving certain performance standards (mostly in reliability), and multi-year rate plan.

The Project Team evaluated the strengths and weaknesses based on the key characteristics of a regulatory model and its performance relative to the policy goals for electricity sector established by the State. Hawaii's current regulatory model's strengths include the following, which will be discussed in detail in Section 4.1:

- PUC's independence and adaptable to the changes in the regulatory environment;
- public participation in the regulatory process;

---

[3] *See*, Section 3.5 discussion on the Future of Hawaii-specific performance-based regulation.

[4] *See*, Section 3.5 discussion on the Future of Hawaii-specific performance-based regulation; Docket No. 2018-0088, Order No. 35411, issued April 18, 2018 ("Order No. 35411").

[5] Order No. 35411, at 52.

[6] Order No. 35411, at 9-10.

- utilities are performing as expected in terms of providing reliable service;
- rates are set to allow the utilities an opportunity to earn a fair return;
- policies are in place to diversify the state's energy portfolio; and
- the proposed PBR will be able to help achieve the clean energy goals if designed correctly.

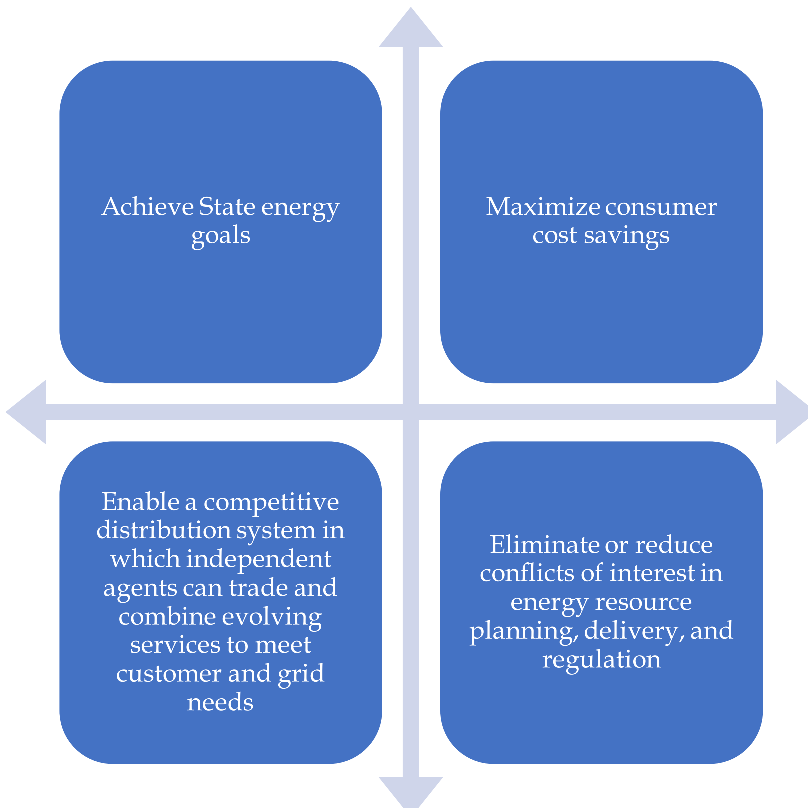
The areas of improvements in the current regulatory model include providing incentives for performance metrics, providing certainty with regards to issuing decisions; and considering other elements of PBR to provide a degree of protection to both the utilities and the ratepayers and to mitigate risks. These mechanisms include re-openers, exogenous factors (or "z-factors"), and true-ups. These will be discussed in detail in Section 4.2.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[7] was contracted to perform this study.[8]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[9] listed in Figure 1.

Figure 1. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition,

[7] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[8] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[9] House Bill No. 1700 Relating to the State Budget.

it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[10]

This deliverable is responsive to Tasks 2.1.2 in the project scope of work.[11] It assesses the existing regulatory model in place in Hawaii and provides a high-level assessment of the strengths and weaknesses of the current regulatory framework.

[10] Hawaii Contract No. 65595. Scope of Services.

[11] This task involves a high-level overview, which may not include all of the detailed nuances, conditions and exceptions that may apply under certain circumstances, which are beyond the scope of this task.

3 Overview of the current regulatory regime in Hawaii

Generally speaking, the regulatory framework in this context refers to the policies, laws and regulations and orders adopted by the State and its agencies to regulate and oversee energy policy and public utilities in the State of Hawaii. This includes statutes enacted into law by the State (by the Legislature and the Governor) that provide mandates, guidance, and authority to State agencies to implement and develop (where authorized), energy policy in Hawaii, and impose certain conditions and requirements on private parties such as regulated electric utilities. The regulatory framework includes rules adopted, and orders issued, by the PUC to implement policies, laws, and regulations. Other government entities also contribute to and are involved in the regulatory process as discussed below.

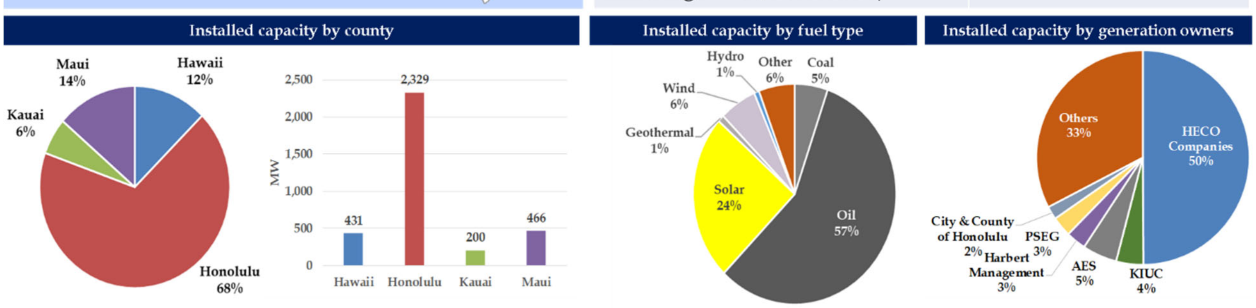
3.1 Overview of the energy market in Hawaii

As described above, each of the four major counties in the State - the City and County of Honolulu, County of Hawaii, County of Maui, and County of Kauai - are served by vertically integrated public utilities: HECO (City and County of Honolulu), HELCO (Hawaii County), MECO (County of Maui), and KIUC (County of Kauai).

Figure 2. Snapshot of the Hawaii market

Hawaii

Key facts	
Installed capacity (as of August 2017)	3,427 MW
Peak demand (2016)	1,784 MW
Load growth (2012-2016)	-3.7%
Transmission lines	1,868 miles
Population	1.42 million
GDP growth (nominal, average annual growth, 2012-2016)	3.7%



Sources: HECO Companies website; KIUC website; HECO Companies' Power Supply Improvement Plans; 2016 State of Hawaii Data Book; HSEO Facts and Figures May 2017

As of August 2017, Hawaii has a total capacity of 3,427 MW.[12] In 2017, approximately 69% net capacity is served by oil, 13% by coal, 3% by biomass, 13% by wind, solar, geothermal, hydroelectric, and biomass, and the 4% by other means.[13] The City and County of Honolulu has the largest installed capacity among the counties, which represents nearly 70% of the State's installed capacity.[14] The HECO Companies own about 50% of the installed capacity in the State, and the subsidiaries are the dominant player in the county that they serve.[15] There are also several IPPs that provide firm generation and variable (as-available) generation[16] as well as customer-sited solar (*i.e.*, DG) in the state.[17]

As discussed in Task 1.5.1., the HECO Companies projected a relatively flat load growth for the next five years in the counties that they serve. Oahu's load growth is projected to decline on average from 2017 to 2021 while Molokai's load growth is relatively flat for the next five years. Load growth (peak demand in terms of MW) in Maui and Hawaii are less than 1% per year at an average of 0.97% and 0.78%, respectively. Only Lanai's load growth is expected to be higher than 1%. KIUC does not appear to have publicly available load forecasts.

The electrical grid on each island is not connected to any other island. The HECO Companies own significant generation, transmission, and distribution assets in each of the counties that they serve. The HECO Companies are investor-owned utilities ("IOU") that supply power to approximately 95% of Hawaii's population.[18] KIUC is a member-owned electric utility cooperative ("co-op").[19] Figure 2 provides an overview of the electricity market in Hawaii.

3.2 Institutions

The main institutional entities involved in the Hawaii electricity market and its regulatory framework are the State Government (Legislative and Executive), the PUC, the Consumer

---

[12] Analysis of generation system is based on data from Hawaiian Electric Companies' 2016 Power Supply Improvement Plan ("PSIP"), SNL, KIUC website, KIUC 2017 Capital Improvements Program for Ensuing Five years, HECO Power Facts, and Power Purchase Contracts data from HEI.

[13] *Hawaii's Electricity Production by Source (Source: EIA)*, Hawaii State Energy Office Website, available at http://energy.hawaii.gov/resources/dashboard-statistics (Last visited May 9, 2018).

[14] *See HECO's Power Facts*, Hawaiian Electric Company's Website, available at https://www.hawaiianelectric.com/about-us/power-facts (Last visited May 9, 2018).

[15] *Ibid.*

[16] *Ibid.*

[17] *Ibid.*

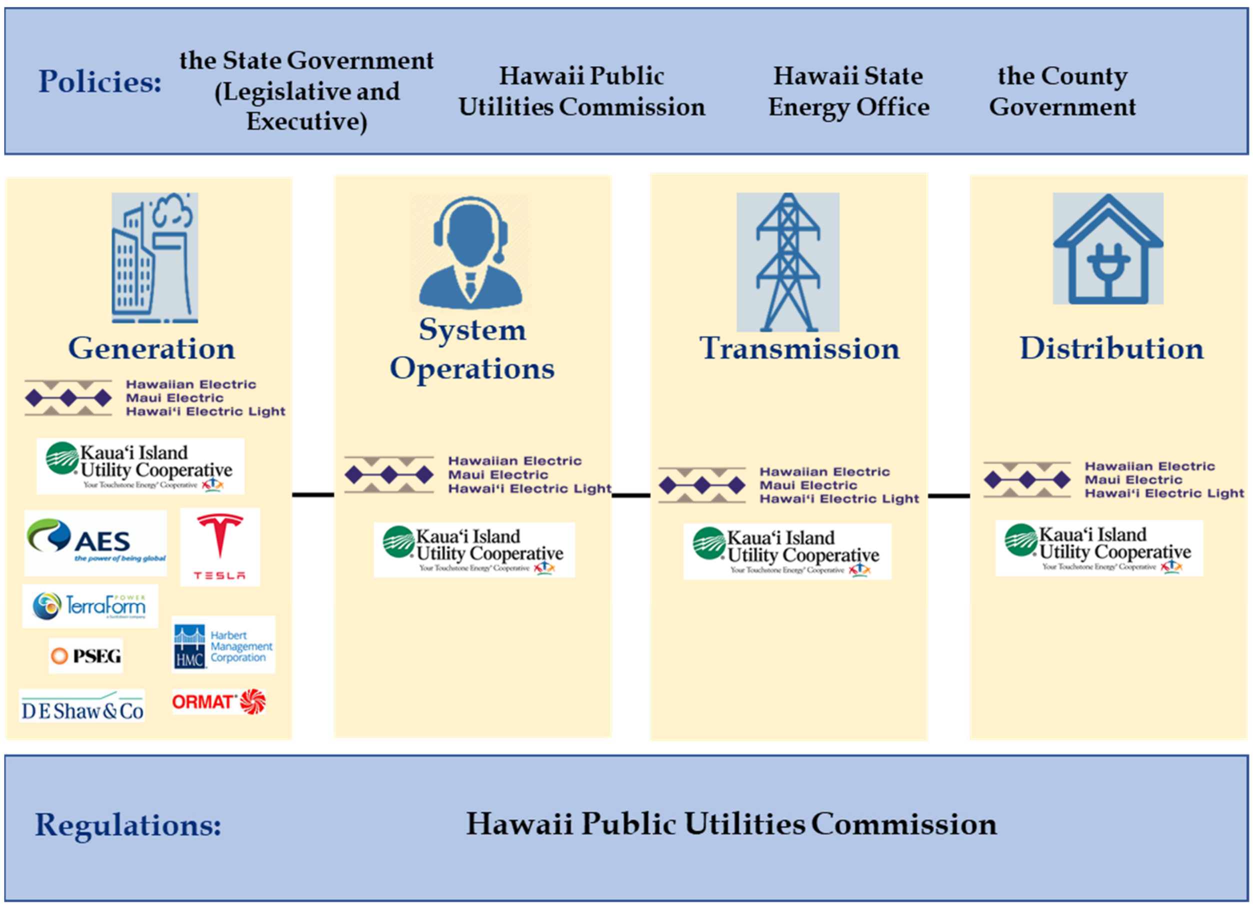
[18] *Ibid.*

[19] *See Energy Page*, State of Hawaii Public Utilities Commission, available at http://puc.hawaii.gov/energy/ (Last Visited May 9, 2018) ("Collectively, HECO, MECO and HELCO are known as the 'HECO Companies' and serve about 95% of the State's population. KIUC on the island of Kauai serve about 5%.")

Advocate, and the HSEO.[20] The HECO Companies and KIUC are regulated public utilities that are regulated by the PUC.[21]

Figure 3 shows the simplified electricity market structure and the players in the State.

Figure 3. Overview of electricity market structure in Hawaii



Note: The list of generation companies above is not exhaustive and should not be interpreted to only refer to utility-scale generation, as distributed generation ("DG") is an important and significant segment of supply.

---

[20] Unlike other states on the mainland, Hawaii is not under the jurisdiction or oversight of Federal Energy Regulatory Commission ("FERC") or the North American Reliability Corporation ("NERC"). See 16 U.S.C. § 824. Also, in Hawaii, county governments do not have authority to regulate the public utilities, but they may participate at times in proceedings before the PUC[should the report reflect that the Counties can indirectly affect utility regulation such as through ordinances related to land use, construction permits?]. *See, e.g.*, Order Granting Intervention, in Dkt No. 2008-0273, filed on November 28, 2008 (Order grants the City and County of Honolulu intervenor status in a proceeding to investigate the implementation of feed-in tariffs).

[21] *See* Energy Page, State of Hawaii Public Utilities Commission, available at http://puc.hawaii.gov/energy/ (May 9, 2018); *See also* HRS § 269-9.

3.2.1 Public Utilities Commission

The PUC in Hawaii, as in other jurisdictions, exercises broad regulatory powers by utilizing its rulemaking authority[22] to adopt and implement rules and regulations that are applicable electric utilities and by using its enforcement and quasi-judicial authority in docket or case proceedings involving public utilities.[23] These proceedings are undertaken in administrative rulemaking processes[24] or formal docket processes.[25] The PUC's primary role is to "protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates."[26] Its stated mission is to:

"…. provide effective, proactive, and informed oversight of all regulated entities to ensure that they operate at a high level of performance so as to serve the public fairly, efficiently, safely, and reliably, while addressing the goals and future needs of the State in the most economically, operationally, and environmentally sound manner, and affording the opportunity for regulated entities to achieve and maintain commercial viability."[27]

HRS Chapter 269 defines and governs the PUC's general functions, responsibilities, staffing, and reports as well as specific policies regarding Renewable Portfolio Standards ("RPS"), Net Energy Metering ("NEM"), Electric Reliability, and Green Infrastructure Bonds, etc. Besides statutes, the PUC regulates the utility companies through its General Orders (such as GO 7), Hawaii Administrative Rules (such as HAR 6-60), and the PUC's orders and decision and orders."

Source: *Relating to Renewable Energy Standards*, HB 623 SD2 CD1, 28th Hawaii Legislature (July 1, 2015); codified in HRS § 269-92; HRS 269-101 *et. seq.*; HRS § 269-161 *et seq.*; PUC General Order No. 7; *Hawaii State Energy Profile*, U.S. Energy Information Administration, available at https://www.eia.gov/state/print.php?sid=HI (Last visited May 11, 2018).

Note: The Commission has been gradually replacing General Orders with Hawaii Administrative Rules

---

[22] *See* HRS § 269-6(a).

[23] *See* HRS §§ 269-6, -7, and HRS Chapter 269 generally.

[24] *See* HRS § 269-6(a); HAR §§ 16-601-146 to -155.

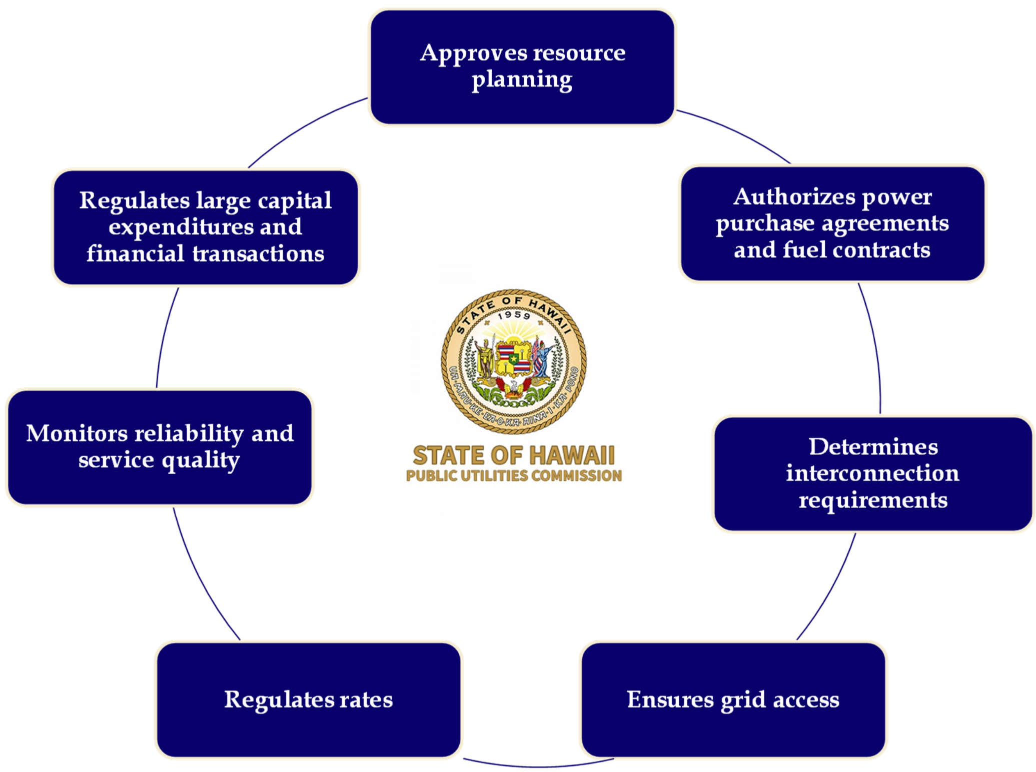
[25] *See* HRS Chapter 269, HAR Title 16 Chapter 601-1.

[26] *Introduction*. Available at http://puc.hawaii.gov/about/introduction/ (last visited April 9, 2018).

[27] *Goals and Objectives of the Commission*, State of Hawaii Public Utilities Website, Available at http://puc.hawaii.gov/about/introduction/ (Last Visited May 18, 2018).

The powers of the PUC include regulating the utilities' rates,[28] reviewing public utility requests for approval of proposed mergers and acquisitions of utilities,[29] authorizing the construction of transmission lines,[30] monitoring the electric reliability,[31] assessing the conditions of each utility in terms of how it operates,[32] regulating its issuance of stocks, bonds, notes and other evidence of indebtedness,[33] and generally investigating utilities as it deems necessary.[34] The most relevant roles will be discussed in the subsections below.

Figure 4. Tasks of the PUC in the electricity sector



[28] HRS § 269-16.

[29] HRS § 269-19.

[30] HRS §§ 269-27.5 and -27.6.

[31] HRS §§ 269-143(a).

[32] HRS § 269-6.

[33] HRS §§ 269-17 through -18.

[34] HRS § 269-7.

As discussed in Tasks 1.3.4. and 1.4.3, the PUC is comprised of three commissioners and each of the commissioners serves a six-year term on a staggered basis.[35] The Governor appoints each of the commissioners, subject to Senate confirmation,[36] and designates the chairperson of the PUC.[37]

3.2.1.1 Rates

One of the primary functions and roles of the PUC is to regulate rates charged by public utilities, which must be "just and reasonable," filed with the PUC and published by the public utility as directed by the PUC.[38] Ratemaking and the ratemaking process are discussed below in Section 3.4.

3.2.1.2 Capital expenditures

Generally, PUC approval is required for HECO Companies' commitments for major capital expenditures, fuel contracts, and power purchase agreements.[39] More specifically, in Hawaii, PUC pre-approval is required for capital expenditures greater than $2.5 million for electric utilities.[40] Usually, the PUC will determine whether the proposed commitment of funds is reasonable and in the public interest.[41] The utility will seek to have the proposed capital expenditures included in its rate base.[42]

3.2.1.3 Financing

The utilities are also required to obtain the Commission's approval before entering into certain types of financing transactions.[43] These transactions include issuing obligations, stocks, revenue

---

35 HRS § 269-2.

36 HRS § 269-2, § 26-34(a).

37 HRS § 269-2(a).

38 HRS § 269-16(a).

39 Section 2.3.(g)(2), General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004; HRS § 269-27.2; and HRS § 269-16.22.

40 Section 2.3.(g)(2), General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004.

41 *See* Order No. 34525, filed in Dkt No. 03-0257, on May 3, 2017 at 12 ("In general, this commission's analysis of capital expenditure applications involves a review of whether the project and its costs are reasonable and consistent with the public interest, among other factors."). (

42 *Ibid*.

43 *See* HRS §§ 269-17 through -19.

bonds, notes and other evidence of indebtedness.[44] The PUC assesses if the request and the terms and conditions of the proposed transaction are in the public interest and is reasonable.[45]

3.2.1.4 Resource planning

The electric utilities were previously required to file an integrated resource plan ("IRP") to the Hawaii PUC every three years[46] The goal of the IRP was to "develop an Action Plan that governs how the utility will meet energy objectives and customer energy needs consistent with state energy policies and goals, while providing safe and reliable utility service at reasonable cost, through the development of Resource Plans and Scenarios of possible futures that provide a broader long-term perspective."[47] In April 2014, the Commission rejected the HECO Companies' IRP Report and suspended the IRP planning cycle.[48]

In August 2014, the Hawaii PUC opened the Docket No. 2014-0183 to consolidate the review of the Power Supply Improvement Plans ("PSIP") filed by the HECO Companies.[49] The PUC stated that "the PSIPs are to include actionable strategies and implementation plans to expeditiously retire older, less-efficient fossil generation, reduce must-run generation, increase generation flexibility, and adopt new technologies such as demand response and energy storage for ancillary services, and institute operational practice changes, as appropriate, to enable integration of a diverse portfolio of additional low cost renewable energy resources, reduction of energy costs and improvements in generation operational efficiencies."[50] On November 4, 2015, the PUC rejected PSIPs filed by the HECO Companies on August 26, 2014, as the PUC identified eight observations and concerns.[51] Based on the guidance from the PUC, the HECO Companies revised the PSIPs and filed their most recent PSIP Update Report on December 23, 2016.[52] This PSIP Update Report was accepted, subject to certain conditions, by the PUC.[53] The PUC also directed the HECO Companies to file a report that "details the Companies' planning approach and

---

[44] HRS § 269 -19.

[45] *Jones v. Hawaiian Electric Co.*, 64 Haw. at 298, 639 P.2d at 1111 (citing *In re Honolulu Rapid Transit Co., Ltd.*, 54 Haw. 402, 409, 507 P.2d 755, 759 (1973)).

[46] Decision and Order "*A Framework for Integrated Resource Planning*, " filed in Dkt No. 2009-0108, on March 14, 2011, Exhibit A at 11.

[47] *Ibid* at 2.

[48] Order No. 32052, filed in Dkt No. 2012-0036, on April 28, 2014, at 80.

[49] Order No. 32257, filed in Dkt No. 2014-0183, on August 27, 2014.

[50] *Ibid.* (quoting Order No. 32052, filed in Docket No. 2014-0183, on April 28, 2014, at *72 - 73*.)..

[51] Order No. 33320, filed in Dkt No. 2014-0183 on November 4, 2015.

[52] *Ibid.*; HECO's PSIPs Update Report, Book 1 through 4, filed in Dkt No. 2014-0913, on December 23, 2016 ("PSIP Update Report").

[53] Order No. 34696, filed in Docket No. 2014-0183, on July 14, 2017.

schedule for the next round of integrated planning." The HECO Companies proposed an Integrated Grid Planning process that included an ambitious leap forward from traditional system planning, i.e. merging three separate planning processes - generation, transmission, and distribution - while simultaneously integrating solution procurement into this merged process.[54]

3.2.1.5 Reliability and Service Quality

As mentioned earlier, the State is not under NERC oversight and therefore, some of the responsibilities that are normally covered by NERC in the mainland are the responsibility of the PUC in Hawaii. These include setting out the reliability standards that the electric utilities need to comply with, which are set forth in HRS Chapter 269, General Order 7 - *Standards for Electric Utility Service in the State of Hawaii,* HAR 6-73, and various orders issued by the PUC from time to time, such as Order No. 30371 in Docket No. 2011-0206, which investigated the implementation of reliability standards for the HECO Companies.

> Paragraph 5.3a. of General Order No. 7 states that "the generation capacity of the utility's plant, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. A statement shall be filed annually with the Commission within 30 days after the close of the year indicating the adequacy of such capacity and the method used to determine the required reserve capacity which forms the basis for future requirements in generation, transmission, and distribution plant expansion programs."
>
> Source: General Order No. 7, as amended by Decision and Order No. 21002, filed in Dkt No. 03-0257, on May 27, 2004; HRS § 269-27.2; and HRS § 269-16.22.at 18.

As required in the Order No. 30371, the HECO Companies should provide monthly reliability reports, including system frequency control performance, significant system events, and curtailment of non-dispatchable renewable resources during the month to the PUC.[55] Some reliability standards do not have any associated rewards or penalties and therefore, are tracking-only metrics, shown in Figure 5.[56]

The System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") have penalties if the prescribed performance target is not met. More specifically, for SAIFI, the performance target is 1.116 interruptions per customer during a one-year period.[57] Penalties are imposed when utilities have greater than 1.206 interruptions per

---

[54] Order No. 35569. Docket No. 2018-0165. Filed on July 12, 2018.

[55] *Order No. 30371 Relating to Various Matters in RSWG Process*, filed in Docket No. 2011-0206, on May 4, 2012 at 17 - 19.

[56] Hawaii PUC, *Service Quality Reliability Annual Reports*. Website, available at. <http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/>. (Last Visited February 16, 2018).

[57] Order 35411, at 44 -45.

customer.[58] The maximum penalty amount is currently $2,039,094, which is determined by calculating 0.20% of Common Equity Share of Approved Average Test Year Rate Base determined in the most recent interim or final order in a general rate case for each HECO Company[59]

Figure 5. Reliability standards and quality of service tracked by the utilities

Metric		Description
ASAI	Average Service Availability Index	Overall availability of electrical service
SAIFI	System Average Interruption Frequency Index	The frequency or number of times a company's customers experience an outage during the year
CAIDI	Customer Average Interruption Duration Index	The average length of time an interrupted customer is out of power
SAIDI	System Average Interruption Duration Index	The average length of time the company's customers are out of power during the year

Source: HECO Annual Service Reliability Reports, last filed August 30, 2017.

Likewise, the maximum penalty for not achieving the performance target for SAIDI is currently at $2,039,094, which is determined by calculating 0.20% of Common Equity Share of Approved Average Test Year Rate Base determined in the most recent interim or final order in a general rate case for each HECO company.[60] The performance target is at 99.03 minutes per outage. Penalties are enforced if outages are longer than 108.10 minutes per outage.[61]

In addition to reliability, the PUC also monitors the utilities' service quality. More specifically, the utilities need to track how fast it answers calls from customers.[62] The Call Center Performance Incentive Mechanism ("PIM") measures the performance of the utility call center in terms of the percentage of calls answered within 30 seconds.[63] There is a reward and penalty for meeting and missing the target.[64] Currently, the maximum reward and penalty is ±$815,638, which is

[58] *Ibid.*

[59] *Ibid.*

[60] *Ibid.* at 45.

[61] *Ibid.*

[62] *Ibid* at 46.

[63] *Ibid.*

[64] *Ibid.*

determined by calculating 0.08% of the most recent interim or final order in a general rate case's Common Equity Share of Approved Average Test Year Rate Base.[65]

3.2.1.6 Interconnection

The PUC also provides guidelines with regards to the interconnection standards and requirements. For example, in 2011, the PUC issued a decision and order to improve Hawaii's interconnection standards for connections to customer's premises, primarily interconnection of distributed generating facilities operating in parallel with HECO Companies' electric systems, which approved a supplemental review process and other measures to limit the scope of systems that must conduct an Interconnection Requirements Study ("IRS").[66] This was subsequently amended in Decision and Order No. 33258, filed in Dkt No. 2014-0192, on October 12, 2015. According to the HECO Companies' Rule 14H, "the technical interconnection standards are based on the requirements of IEEE 1547-2003 *Standard for Interconnecting Distributed Resources with Electric Power Systems*."[67]

3.2.1.7 Investigative proceedings

The PUC has the power to initiate investigatory proceedings to examine different issues.[68] Examples of these energy policy issues include, but are not limited to, a renewable energy infrastructure program,[69] on-bill financing programs,[70] community-based renewable energy,[71] distributed energy resources,[72] and performance-based regulations.[73] In some instances, the Commission will open an investigatory docket to comply with a legislative mandate. An example of this is the community-based renewable energy proceeding.[74] The PUC may also hold conferences and workshops to discuss various matters and to share information among stakeholders.

---

[65] *Ibid*.

[66] Decision and Order No. 30027, filed in Dkt No. 2010-0015, on December 20, 2011.

[67] HECO Companies' *Rule 14 H,* at Superseding Tariff Sheet No. 34B-2, effective February 20, 2018.

[68] HRS § 269-7.

[69] Order No. 23913 *Instituting a Proceeding to Examine HECO Companies' Proposal for a Renewable Energy Infrastructure Program*, filed in Dkt No 2007-0416, on December 20, 2007.

[70] *See* Order No. 32114 *Re Establish and Implement On-Bill Financing Program*, filed in Dkt No. 2014-0129, on June 3, 2014.

[71] *See* Order No. 33358, filed in Dkt No. 2015-0389, on November 27, 2015.

[72] *See* Order No. 32269 *Instituting a Proceeding to Investigate Distributed Energy Resource Policies,* filed in Dkt No. 2014-0192, on August 21, 2014.

[73] *See* Order No. 34511 *Institution a Proceeding to Investigate Performance-Based Regulations*, filed in Dkt No. 2018-0088, on April 18, 2018.

[74] *See* Order No. 33358, filed in Dkt No. 2015-0389, on November 27, 2015.

3.2.1.8 Monitoring

The electric utilities are also required to submit various annual reports to the PUC for monitoring purposes. These reports include the following (not exhaustive list):

- information on the total rated generating capacity produced by eligible customer-generators that are customers of that utility in the utility's service area;[75]
- performance metrics (to be posted on the utilities' website with a link to the metrics on the website's homepage);[76]
- financial report with certification that such report conforms with the applicable uniform system of accounts adopted by the commission;[77]
- all accidents caused by or occurring in connection with its operations and service;[78]
- energy resource by generation category to its existing and new retail electricity customers for the prior calendar year;[79] and
- the average retail price of electricity (per kilowatt-hour) for each rate class of service for the prior calendar year.[80]

3.2.2 Hawaii State Legislature

The Hawaii State Legislature, co-equal to the executive and judicial branches of Hawaii's state government, is responsible for making laws. The House Committee on Energy & Environmental Protection focuses on programs relating to energy resources and the development of renewable and alternative energy resources, energy conservation, environmental quality control and

[75] HRS §269-103. Generating Capacity.

[76] *Key Performance Metrics*, HECO Companies' Website, available at https://www.hawaiianelectric.com/about-us/key-performance-metrics (Last Visited May 14, 2018).

[77] *Annual Financial Reports (AFR) for Electric Utilities*, State of Hawaii Public Utilities Commission Website, available at http://puc.hawaii.gov/reports/energy-reports/annual-financial-reports-electric-utilities/ (Last Visited May 14, 2018).

[78] *See* Hawaiian Electric Companies Annual Service Reliability Reports, available at http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/ (Last Visited May 14, 2018).

[79] *See* Renewable Portfolio Standard Status (RPS) Annual Reports (Electric, Docket 2007-0008), available at http://puc.hawaii.gov/reports/energy-reports/renewable-portfolio-standards-rps-annual-reports/ (Last Visited on May 14, 2018).

[80] Average Price of Electricity, available at https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity (Last Visited May 14, 2018).

protection, and environmental health, and other pertinent matters referred to it by the House.[81] Likewise, the Senate has the Senate Committee on Transportation and Energy, which focuses on programs relating to air, water, and surface transportation, and transit-oriented development as it relates to transportation projects; and energy resources, including the development of alternative energy resources.[82] In addition, the Senate Committee on Commerce, Consumer Protection, and Health oversees regulations relating to public utilities and other regulated business, and the House Committee of Consumer Protection oversees programs relating to consumer protection and the regulation of utilities as well.[83]

3.2.3 Consumer Advocate

The Consumer Advocate is statutorily mandated to represent, protect, and advance the interests of all consumers of utility services.[84] By statute, the Consumer Advocate is a party to all PUC proceedings,[85] and as such reviews filings from utilities, may request information from public utilities that will be helpful to perform its duties, and represents consumer interests before the PUC.

3.3 Rulemaking process

Under Hawaii law, a rule is defined as follows:

> "Rule" means each agency statement of general or particular applicability and future effect that implements, interprets, or prescribes law or policy, or describes the organization, procedure, or practice requirements of any agency. The term does not include regulations concerning only the internal management of an agency and not affecting private rights of or procedures available to the public, nor does the term include declaratory rulings issued pursuant to section 91-8, nor intra-agency memoranda.

With respect to the PUC, the rulemaking process usually involves the PUC, on its own motion, proposing a draft of rules.[86] This is then followed by a public hearing, a period of ten (10) days following the hearing for all interested persons to submit written comments, and final action by

---

[81] *House Committee on Energy & Environmental Protection*. Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=EEP (Last Visited April 19, 2018).

[82] *Senate Committee on Transportation and Energy,* Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=TRE&year=2018 (Last Visited May 14, 2018).

[83] *House Committee on Consumer Protection & Commerce*, Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=CPC&year=2018 (Last Visited May 14, 2018).

[84] *See* HRS § 269-51.

[85] *See* HRS § 269-51.

[86] HAR § 16-601-146; HRS § 269-6.

the PUC within forty-five (45) days of the deadline to submit comments, unless a different date is set by the PUC.[87]

Figure 6. PUC's rulemaking process

- The PUC is authorized and/or required by statute to promulgate rules
- PUC, on its own motion, or on a petition by an interested person, initiates proceedings to adopt, amend, or repeal any rule of the PUC
- A notice of a public hearing is issued, and the proposed rules are required to be made available on the Lieutenant Governor's website, and is posted on the PUC's website
- A public hearing is held
- Written comments can be submitted within ten days of the last day of a public hearing
- After considering all statements, views, comments, and documents, the PUC issues a final action in a rulemaking proceeding within, unless the PUC indicates otherwise, forty-five (45) days of the deadline to submit comments
- The proposed rules are approved by the Governor
- If the proposed rules are approved by the Governor, a certified copy of the proposed rules are filed with the Lt. Governor and is considered effective within ten (10) days after such filing, unless a later date is specified; provided that, such later date is no greater than thirty (30) days after filing

Source: HRS §§ 91-1 to -2; HRS § 91-6; HRS §§ 269-6, -6.5(b), -15(b)(4), -44, -96(b) and (c), -102(a) and (b), -111(c), -121(a) and (b),-123(a) and (b), -142(a), -144(c), 145(a), and -146(a).HAR § 16-601-146(a); HAR §§ 16-601-146 to -154

The proposed rules are then subject to the Governor's approval.[88] Upon approval by the Governor, certified copies of the rules are filed with the Lieutenant Governor's office and such

[87] HRS § 91-3; HAR §§ 16-601-150 to -154.

[88] HRS § 91-3; HAR §§ 16-601-146 to -154

rule becomes effective within ten (10) days of this filing, unless another date is specified[89] In addition to the PUC, any interested person may petition the PUC to adopt, amend, or repeal any rule of the PUC.[90] The PUC shall, within thirty days after the filing of a petition for rulemaking, either deny the petition or initiate proceedings.[91] If the PUC finds that emergency rulemaking is required, it may modify the procedures enumerated above.[92]

3.4 Ratemaking

Pursuant to HRS § 269-16, all rates, schedules, rules, and practices made or charged by public utilities are required to be filed with the PUC.[93] For any increase in rates, the PUC must hold a contested case hearing preceded by a public hearing at which consumers may present testimony concerning the increase.[94] Electricity rates in Hawaii are generally determined using the cost of service ("COS") approach. Due to differences in ownership structure, the approaches used by the HECO Companies and KIUC differ and are discussed in further detail below. The approach used for the HECO Companies has been modified from traditional COS ratemaking to incorporate certain elements of PBR. Each of the utilities also utilizes certain automatic rate adjustment clauses to automatically adjust for variability in fuel or purchased power costs between rate cases.[95]

3.4.1 Ratemaking Process

The current ratemaking process generally begins when a utility files notice of its intent to file for a general rate increase at least two months prior to filing a rate application.[96] Generally, utilities request rate adjustments when costs have increased, and major investments have been or are being made and revenues collected no longer generate a sufficient rate of return sufficient in magnitude to justify the time and expense of applying for a rate increase, or when required by

---

[89] Provided that such other date is not more than thirty (30) days after filing. HRS § 91-4; HAR § 16-601-154.

[90] HRS § 91-6; HAR § 16-601-146(b).

[91] HRS § 91-6; HAR § 16-601-148(a); *See also* HAR §§ 16-601-146 to -155. An example of this process is currently occurring with the PUC moving HAR Chapters 16-601, 6-63, 6-65, and 6-68, to Chapter 16-601, 16-603, 16-605, and 16-608, respectively. *See Proposed Rule Making*, PUC Website, available at http://puc.hawaii.gov/about/statutes-rules-orders/proposed-rulemaking/ (Last visited May 15, 2018).

[92] HRS § 91-3; HAR § 16-601-155.

[93] HRS § 269-16(a).

[94] HRS § 269-16(b).

[95] *See* HRS § 269-16(d), (g); HAR § 6-60-6.

[96] HAR § 16-601-85(a).

the PUC. For example, KIUC has not filed a rate case since 2010.[97] In contrast, each of the HECO Companies is required to file a rate case every three years.[98]

The application describing the proposed change in rates is then submitted to the PUC along with written direct testimony justifying the requested increase as well as supporting exhibits and workpapers.[99] The Commission must make a determination as to whether the application is complete under HRS Chapter 269, as the deadline for the Commission to complete its deliberations and issue its decision begins only after a completed application is filed and served on the Consumer Advocate.[100] The Consumer Advocate will have twenty-one days to object to the sufficiency of the application.[101] Accordingly, the Consumer Advocate will typically file a statement of position regarding the completeness of the application and the Commission will issue an order establishing the date the completed application was filed.[102]

As required by statute, the PUC will hold a public hearing for each rate case.[103] Interested persons can file motions seeking to intervene or participate in the docket, which must be filed no later than ten days after the last public hearing.[104] The PUC, the Consumer Advocate, and any admitted intervenors or participants,[105] may submit information requests to build the record in the proceeding, as may be allowed and subject to any conditions and limitations that may be established by the PUC.[106] Typically, the utility, the Consumer Advocate, and any parties granted full intervenor status, may negotiate and file a stipulation or partial stipulation for the commission to review if they have reached an agreement on certain issues.[107] Additional

---

[97] *See* Docket No. 2009-0050, Order Closing the Docket, issued Oct. 12, 2010, at 1-2.

[98] *See* Docket No. 2008-0274, Final Decision and Order, issued Aug. 31, 2010, at 129 ("So that the commission and the Consumer Advocate have a regular opportunity to evaluate decoupling and re-calibrate RAM inputs using commission-approved values, the HECO Companies shall file staggered rate cases every three years.").

[99] *See* HAR § 16-601-87 (applies to utilities with Annual Gross Operating Revenues of $2,000,000 or more).

[100] HRS § 269-16(d); HAR § 16-601-86, -87.

[101] HRS § 269-16(d).

[102] *See, e.g.*, Docket No. 2016-0328, Division of Consumer Advocacy's Statement of Position Regarding Completeness of Application, filed Jan. 5, 2018; Docket No. 2016-0328, Order No. 34664, issued June 28, 2017 (certifying completeness of the application).

[103] HRS § 269-16(b).

[104] HAR 16-601-57(1).

[105] "Intervenor" means a person who moves to intervene in a contested case and is admitted as a party; "participant" means a person allowed to participate in a proceeding pursuant to section 16-601-56. See HAR 16-601.

[106] The scope and schedule of information requests are governed in dockets by procedural orders and schedules issued by the PUC.

[107] *See, e.g.*, Docket No. 2016-0328, Parties' Stipulated Settlement Letter, filed Nov. 15, 2017.

testimony and rebuttal testimony may be taken and evidentiary hearings may be held on any unsettled issues.[108]

Generally, the PUC reviews and determines the total annual revenues required by the utilities to cover its projected expenses and provide it with an opportunity to earn a fair return on its investments. The PUC is required by statute to issue its decision as expeditiously as possible, and within nine months from the date the public utility filed its completed application.[109] If the PUC is unable to issue a final decision within the prescribed time period, it must issue an interim decision allowing an increase in rates, fares, and charges, if any, to which the PUC believes the utility is probably entitled.[110] Subsequently, the PUC will have to issue a final decision and order that either adopts the interim decision and order or may reflect modifications from the interim decision and order.

3.4.2 Ratemaking for the HECO Companies

For the investor-owned HECO Companies, as discussed below, rates are determined using a rate of return COS approach, with some variations that includes some components associated with PBR, namely the use of: multi-year rate plans, earnings sharing mechanisms ("ESM") between the utility and the customers for the HECO Companies, decoupling using a revenue adjustment mechanisms ("RAM") subject to a revenue cap and using revenue balancing accounts ("RBA"), and recently performance incentive mechanisms ("PIM"). In addition, the HECO Companies' rates include a new Energy Cost Recovery Clause,[111] which shall be consistent with the terms of fuel contracts, distributed generation contracts, and purchased energy contracts. Changes to the Energy Cost Recovery Clause may be proposed by application to the PUC.[112]

3.4.2.1 Calculating revenue requirements

Under a traditional COS approach, revenue requirements identify the expected amount of revenue the utility requires to cover its COS for a given forecasted twelve month period (referred to as a "test year").[113] As shown in the formula below (and discussed in detail in Task 1.6.1), the revenue requirements are comprised of the rate base multiplied by the allowed rate of return plus

---

[108] *See, e.g.*, Docket No. 2016-0328, Procedural Order No. 34721, issued July 28, 2017, at 9-11 (procedural schedule); Docket No. 2016-0328, Order No. 35219 *Amending Procedural Order No. 34721*, issued July 28, 2017, at 7-8,13-14 (revised procedural schedule reflecting settlement and interim order).

[109] HRS § 269-16(d).

[110] HRS § 269-16(d).

[111] As approved by the PUC in the final decision and order under Docket 2016-0328, the Energy Cost Recovery Clause replaced the original Energy Cost Adjustment Clause ("ECAC").

[112] Order No.35927. Docket No. 2016-0328. Page 14.

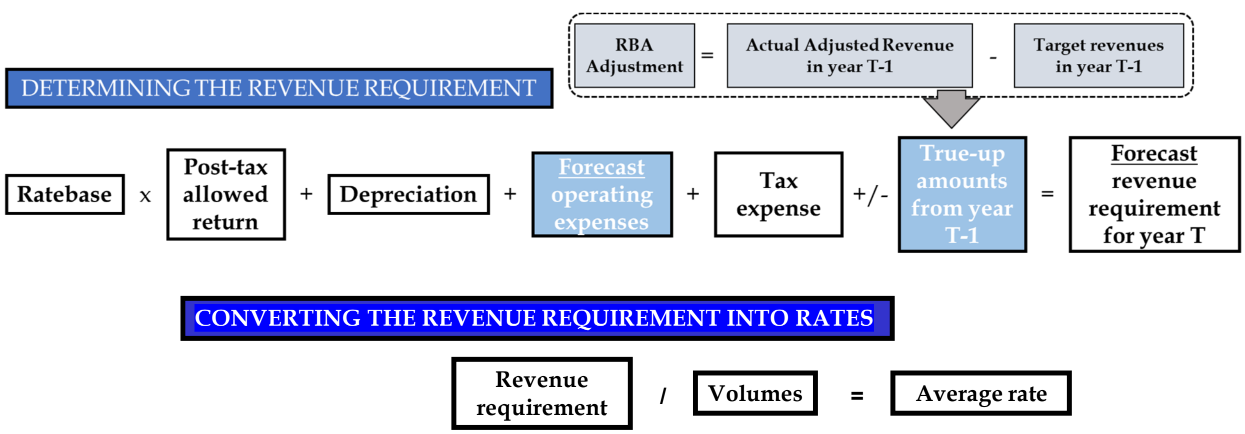
[113] *See,* HAR § 16-601-87(4).

the sum of depreciation and amortization expenses, operating expenses, and tax expenses.[114] Under the COS approach, the operating and other expenses as well as the cost of power are costs that are passed through to customers and do not provide a "return on investment" to the utilities. On the other hand, generally, the rate base (which includes the investments in net utility plant and other items such as regulatory assets and working capital) is multiplied by the PUC-approved rate of return to determine the revenue required. The HECO Companies estimate the rates of return they propose for PUC approval based on "multiple analytical techniques including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium approach."[115]

As shown in the revenue requirement formula below, the utility's ability to increase earnings is tied to increases in the rate base and higher approved levels of rates of return. As a result, the traditional COS approach may create an incentive for the utility to spend more on capital expenditures to increase the overall associated returns it receives on investments. This is one of the reasons given for the recent passage of the Hawaii Ratepayer Protection Act.[116] See Section 3.5 for further discussion on this new law and the PUC's PBR proceeding related to the law's objectives.

$$\begin{aligned} &\mathit{Traditional\ COS\ Revenue\ Requirements} \\ &\qquad = (\mathit{Rate\ Base} * \mathit{Approved\ Rate\ of\ Redurn}) + \mathit{Operating\ Expenses} \\ &\qquad + \mathit{Depreciation\ and\ Amortization\ Expenses} + \mathit{Tax\ Expenses} \end{aligned}$$

Figure 7. Determining the revenue requirements and rates



Note: RBA = Revenue Balancing Account

[114] *See, generally*, Docket No. 2016-0328.

[115] *See, e.g.*, Docket No. 2016-0328, Direct Testimonies and Exhibits, Book 9, HECO T-28 Executive Summary, filed December 16, 2016.

[116] *See* 2018 Haw. Sess. Laws Act 5 § 1.

3.4.2.2 Hawaii-specific performance-based regulation applicable to the HECO Companies

The current regulatory framework also has some components associated with PBR. These include a fixed three-year cycle for general rate cases, the decoupling mechanism, an ESM, an interim-period revenue adjustment mechanism which includes a revenue cap, and performance incentive mechanisms ("PIMs"). The decoupling mechanism consists of a Revenue Balancing Account ("RBA") and the Revenue Adjustment Mechanism ("RAM").

- **Multi-Year Rate Plan ("MRP")**: MRPs permit utilities to operate for several years (typically three to five years) without a general rate case.[117] The HECO Companies are on fixed three-year general rate case cycles.[118]

- **RBA Decoupling Mechanism**: Revenue decoupling "de-links" the utility's revenues from the volume of electricity sales. In other words, decoupling aims to eliminate the financial detriment caused by reduced electricity sales and thus the utilities' disincentive to pursue energy efficiency measures and utilize more distributed energy. RBA is "the sales decoupling component, which is designed to break the link between the HECO Companies' sales and their total electric revenues by setting the target revenues to the most recent authorized revenue level approved in each utility's most recent rate case."[119] Under the RBA, the HECO Companies recover PUC-approved "Target Revenues" (and no more or less). Base rates are adjusted using a per kWh rate adjustment (the "RBA Rate Adjustment"), which is calculated by dividing a sum which includes the calendar year-end balance in the RBA balance as well as certain adjustments included in the RAM and PIM provisions by the Company's forecast of MWh sales over the RBA Rate Adjustment recovery period.[120]

- **RAM Decoupling Mechanism**: The RAM is designed to "compensate [the] HECO Companies for increases in utility costs and infrastructure investment between rate cases through formula-driven estimates."[121] Because of the RAM, the HECO Companies do not have to wait until the next general rate case to recover the approved costs and infrastructure investments and instead may do so between rate cases. Items that are subject to yearly update and escalation through the RAM include labor and non-labor O&M and payroll tax expenses, return on incremental investment, updated depreciation

---

[117] Order No. 35411, at 16.

[118] Order No. 35411, at 41.

[119] Docket No. 2013-0141, Order No. 32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule, issued March 31, 2015, at 9-10.

[120] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf .

[121] *Ibid.*

and amortization expenses, and changes in costs due to significant changes in tax laws or regulations.[122]

- **RAM Revenue Cap**: In the event that the RAM Revenue Adjustment exceeds the Target Revenue for the rate case test year, increased by the compound Gross Domestic Product Price Indicator ("GDPPI") for each year following the test year, the RAM Revenue Adjustment will be capped, and excess expenses will not be recoverable under the RAM Revenue Adjustment.[123]

- **Earnings Sharing Mechanism ("ESM")**: ESMs are generally designed so that the extraordinary earnings (or losses in some jurisdictions) are shared between the utility and its customers rather than retained (or absorbed) entirely by the utility. In the case of the HECO Companies, the ESM is asymmetrical where only excess earnings (*i.e.*, where utility earnings are greater than the authorized return on equity ("ROE")) are shared with the customers. This means that where there are no excess earnings (*i.e.*, earnings are at or below the authorized ROE), any lower than expected earnings will be fully absorbed by the utility's shareholders and not by its ratepayers. In other words, if the utilities' ROE is at or below the authorized ROE, any earnings will be retained entirely by shareholders. The Table below shows the ROE at or below the authorized ROE and the sharing: [124]

ROE at or below the Authorized ROE	Retained entirely by shareholders – no customer credits
First 100 basis points (1%) over Authorized ROE	25% share credit to customers
Next 200 basis points (2%) over Authorized ROE	50% share credit to customers
All ROE exceeding 300 basis points (3%) of Authorized ROE	90% share credit to customers

Source: Order No. 35411, at 43.

- **Performance Incentive Mechanisms ("PIMs"):** PIMs consist of metrics, targets, and incentives used to address performance and provide regulatory guidance and incentives regarding the implementation of new technologies and practices.[125]

---

[122] Order No. 35411, at 43.

[123] *See,* Order No. 35411, at 42-43.

[124] Order No. 35411, at 43.

[125] Order No. 35411, at 17.

- **Service Quality (Traditional) PIMs:** Currently, the HECO Companies' rates are based in part on penalty PIMs based on achieving service outage frequency ("SAIDI") and duration ("SAIDI") metrics as well as a PIM for call center performance which provides either a penalty or a reward.[126]

- **Targeted Energy Policy PIMs:** Recently, the PUC has approved incentive PIMs related to the HECO Companies' achievement of cost savings in renewable generation procurement as well as the implementation of the HECO Companies' demand response portfolio.[127]

As noted below, these PBR elements are incorporated into the HECO Companies' rates using the RBA Rate Adjustment.[128] This is independent of the establishment of the HECO Companies' base rates for each rate case test year based on traditional COS methods.

3.4.2.3 Calculating Rates and Rate Design

After calculating the revenue requirements, the revenue requirements are then allocated to various customer classes as a function of cost to provide service to each customer class to determine and design the rates to be charged to the various classes of customers. The HECO Companies use a cost of service study to determine the cost responsibility assigned to different customer classes for ratemaking purposes.[129] All of the costs incurred in providing electric service to customers are incorporated in the embedded cost of service study, including the estimates of operation and expenses, depreciation expenses, taxes, plant costs, and return on capital.[130] Three major steps are involved in the embedded cost of service study methodology, as shown in Figure 8.[131]

As discussed in Task 1.6.4, the HECO Companies calculate the rates for Residential and Small Power Use Business mainly based on energy consumption. The rates that have been established for the customer classes vary according to customer class and level of consumption and may include various additional charges and adjustments. For example, there is a customer charge ($ per customer per month) and a Green Infrastructure Fee ($ per customer per month) added to all

---

[126] Order No. 35411, at 44-46.

[127] Order No. 35411, at 46-47.

[128] *See*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Revenue Balancing Account ("RBA") Provision, *available at* https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rates/heco_rates_rba.pdf

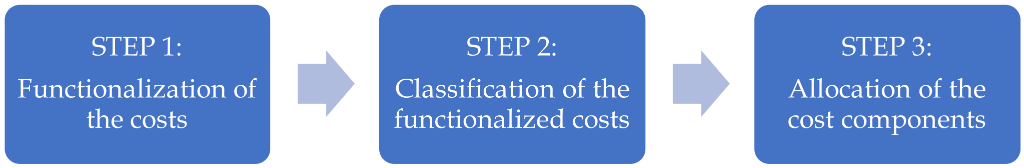
[129] For more information on this, please refer to the Working Paper for Task 1.6.4.

[130] *Ibid.*

[131] *Ibid*, at 10.

bills.[132] As additional examples, rates for Medium Power Use Business, Large Power Use Business, and Large Power Use Business, Directly Served include a demand charge ($ per kW), as well.[133] The HECO Companies also provide an optional Time-of-Use ("TOU") pilot rate program for Schedule R, G, J, and P rate classes.[134]

Figure 8. Key steps in the cost of service study methodology



In addition to the computation of base rates described above, amounts charged to the HECO Companies' customers are adjusted for changes in short-term fuel prices and purchased energy expenses, as well as changes in certain non-energy costs associated with purchased power using the ECAC and PPAC.[135]

3.4.3 Ratemaking for KIUC

For member-owned cooperative KIUC (*i.e.*, not an investor-owned, for-profit public utility), rates are determined using a debt service coverage COS approach known as Times Interest Earned Ratio ("TIER"). In addition, KIUC's rates include an Energy Rate Adjustment Clause ("ERAC"), which recovers certain variable fuel and purchased energy costs. These rate design elements will be discussed in greater detail below.

3.4.3.1 Calculating revenue requirements

As discussed in Task 1.4.2., KIUC's revenue requirement calculation is based on somewhat different principles than those used for the HECO Companies. While maintaining financial integrity is important to KIUC, its revenue requirement target is mainly designed to meet its debt obligations rather than to provide a reasonable rate of return for shareholders of an investor-owned public utility. KIUC's equity is held primarily by its customer-members, who make contributions for service and not with a set expectation of receiving a return. Therefore, the

---

[132] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules R and G, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates.

[133] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules J and P, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates.

[134] *See, e.g.*, Tariff Applicable to Electric Service of Hawaiian Electric Company, Inc., Schedules TOU-R and TOU-J, *available at* https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates. Participation is voluntary. Currently, only HELCO and MECO (not HECO) have Time-of-Use Schedule TOU-P.

[135] Order No. 35411, at 47-48.

revenue requirements of a co-op are set using a Times Interest Earned Ratio ("TIER") level, as discussed in Task 1.4.2. TIER is a solvency ratio that measures a co-op's ability to meet its long-term debt obligations. It is calculated by dividing the sum of net income and total interest expense by total interest expense. Net income is essentially the operating margin in the case of KIUC. The formula for the TIER level is:

$$TIER = (Earnings\ Before\ Interest\ and\ Taxes)/(Interest\ Expense)$$

The ratio measures how many times KIUC can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25[136] for distribution utilities, the PUC has set the current regulated TIER level for KIUC at 2.27.[137] The operating revenue remaining after operating expenses and debt service is a co-op's net margin for that year. The revenue requirement for KIUC is set so that it earns a sufficient margin to achieve the target TIER level. This margin helps KIUC to maintain financial stability and make the necessary investments on the grid.

From the formula for TIER level, the following can be inferred:

$$TIER = (Interest\ Expense + \ Margins)/(Interest\ Expense)$$

$$TIER = (Revenues - Operating\ Expenses)/(Interest\ Expense)$$

$$Revenues - Operating\ Expenses = Interest\ Expense * TIER$$

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expenses$$

KIUC's revenue requirements comprise of interest expense, TIER level, and operating costs:

1. Interest expense

   a) <u>Capital structure</u> helps to determine how much debt the co-op can carry. A higher debt-capital ratio increases the interest expense and thus the revenue requirements. This is the opposite for an IOU, which can increase leverage to lower the WACC.

   b) <u>Interest rates</u> are lower for co-ops than IOUs. Co-ops have access to low-cost debt from public and private sources that IOUs do not, enabling them to lower their financing cost.

2. TIER level – set by the regulator.

3. Operating costs – generally the same as for IOU, with the exception that <u>tax expenses</u> are lower for co-ops because they are exempt from federal income taxes.

---

136 *See* Docket No. 2009-0050, Application, Volume 1, filed June 30, 2009, at 10.

137 Docket No. 2009-0050, Decision and Order, issued September 9, 2010, at 1-2.

3.4.3.2 Calculating Rates and Rate Design

After calculating the revenue requirements based on the approved TIER level, revenue requirements are then allocated to customer classes as a function of cost to provide service to each customer class in a manner similar to the COS method used by the HECO Companies. Like the HECO Companies, KIUC also uses the embedded cost approach for the cost of service analysis, including the functionalization, classification, and allocation of revenue requirement.[138]

KIUC calculates rates based on customer charges and energy consumption for Residential and Small Commercial, but also includes a demand charge for Large Commercial and Large Power (Primary and Secondary).[139] Also, KIUC also has a pilot TOU rate program for Residential and limited to approximately 300 residential customers who are duly selected to participate in the program.[140] KIUC's rates are then adjusted pursuant to an Energy Rate Adjustment Clause ("ERAC") which accounts for changes in the price of fuel and purchased energy as compared to the 2010 test year.[141]

3.5 Future of Hawaii-specific performance-based regulation

On April 24, 2018, the Governor of Hawaii signed the Hawaii Ratepayer Protection Act.[142] This new law aims to address concerns that the current traditional regulatory approach may not provide appropriate incentives to utilities to meet the challenges of a renewable and distributed energy future.[143] The law directs the PUC to create "performance incentives and penalty mechanisms that … break the direct link between allowed revenues and investment levels" by January 1, 2020.[144] The Hawaii Ratepayer Protection Act directs the PUC to consider economic incentives, penalties, and cost-recovery rules that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, rapid integration of renewables, and timely execution of competitive procurement and other business processes.[145] Among the reasons to explore and implement PBR mechanisms are to align the regulatory framework and the utilities' financial interests with the public interest.[146]

---

[138] Docket No. 2009-0050, Application, Volume 2, filed June 30, 2009, Exhibit KIUC 10-T-600, at 4.

[139] *See* KIUC Tariff No. 1, Schedules "D", "G", "J", "L", and "P", *available at* http://website.kiuc.coop/content/tariffs.

[140] *See* KIUC Tariff No. 1, Schedule "TOU-S", *available at* http://website.kiuc.coop/content/tariffs.

[141] *See, e.g.* KIUC Tariff No. 1, Schedules "D", "J", and "P", *available at* http://website.kiuc.coop/content/tariffs.

[142] Gov. Msg. No. 1105 (April 24, 2018); *see also* 2018 Haw. Sess. Laws Act 5.

[143] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

[144] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[145] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5.

[146] Order No. 35411, at 51; *see also Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

Related to the objectives of the Hawaii Ratepayer Protection Act, the PUC issued Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, on April 18, 2018, opening Docket No. 2018-0088, a proceeding to investigate the PBR for the HECO Companies ("PBR Docket").[147] The PUC intends for Docket No. 2018-0088 to be "a forum by which to evaluate the current regulatory environment; identify which elements, if any, may not adequately align with the public interest; and collaboratively develop modifications or new components to better align utility and customer interests."[148] The Commission aims to "(1) identify specific areas of utility performance that should be improved; (2) determine appropriate metrics for measuring successful outcomes in those areas; and (3) establish reasonable financial rewards and/or penalties that are sufficient to incent the utility to achieve those outcomes."[149]

According to Order No. 35411, PBR includes a "set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes as opposed to simply growth in capital investments or other determinants of utilities earnings" under traditional COS rate regulation.[150] PBR offers regulators a way to restructure utility financial incentives to achieve broad objectives such as incenting cost reduction and achievement of policy goals, improving unsatisfactory performance, integrating technological advances, and supporting customer choice.[151]

In Docket No. 2018-0088, the PUC stated that it is particularly interested in PBR mechanisms that result in:

- "Greater cost control and reduced rate volatility;
- Efficient investment and allocation of resources regardless of classification as capital or operating expenses;
- Fair distribution of risks between utilities and customers; and
- Fulfillment of state policy goals." [152]

[147] Order No. 35411.

[148] Order No. 35411, at 51.

[149] Order No. 35411, at 52.

[150] Order No. 35411, at 13.

[151] Order No. 35411, at 14.

[152] Order No. 35411, at 5.

PBR framework vs. Performance Incentive Mechanisms ("PIMs"), according to the PUC

"PBR frameworks constitute a wholesale change in the regulatory procedures and cost control incentive associated with the traditional ratemaking process by, among other things, allowing utilities to profit from realized cost efficiencies and establishing financial rewards or penalties based on utility performance according to specific incentive metrics."

"Standalone PIMs can provide financial rewards and/or penalties for utility performance according to specific metrics, without necessarily requiring a substantial change to other ratemaking procedures."

Source: Docket No. 2018-0088, Order No. 35411, issued April 18, 2018, at 37.

The proceeding will be implemented in two phases. During Phase 1, the current regulatory framework will be assessed and evaluated. Specific areas of utility performance that should be targeted for improvement and metrics for determining successful outcomes in those areas will be identified. [153] During Phase 2, the PUC will focus on refinements and modifications that can be made to the existing regulatory framework to incent the utility to achieve those outcomes. New PBR frameworks will be developed, including performance incentives, to increase the alignment between the utilities' interests and those of the customers. [154] The Commission expects Phase 1 to conclude in "approximately nine months" while Phase 2 will take approximately 12 months.[155]

As a member-owned cooperative electric utility, the Hawaii Ratepayer Protection Act does not apply to KIUC.[156] In addition, pursuant to Order No. 35411, KIUC is waived from involvement in Docket No. 2018-0088 because the method used by KIUC to determine rates, which is the TIER approach discussed above, is "unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit."[157]

[153] Order No. 35411, at 53.

[154] Order No. 35411, at 55.

[155] Order No. 35411, at 55.

[156] *See Hawaii Ratepayer Protection Act*, 2018 Haw. Sess. Laws Act 5, § 3.

[157] Order No. 35411, at 9-10.

4 General assessment of the strengths and challenges of the current regulatory model in Hawaii

The assessment of the current regulatory model, including its strengths and weakness, is high level and qualitative. The Project Team evaluated the strengths and weaknesses based on the key characteristics of a good regulatory model and its performance relative to the policy goals for electricity sector espoused by the administration. As will be discussed below, the strengths of the current regulatory model include PUC's "independence", participatory regulatory process, rates are set to allow utilities a fair return, and policies are in place to achieve diversifying the state's energy portfolio. Areas for improvements include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, and taking into account other elements that mitigate risks in the final design of the PBR.

4.1 Strengths of the current regulatory model

The current regulatory model has several strengths including the PUC's independence and innovativeness, a participatory regulatory process, a regulatory model that allows rates to be set to allow utilities a reasonable rate of return, and policies that are in place to achieve diversifying the state's energy portfolio. These are detailed further below:

- **PUC is independent and innovative**. The PUC is structured with fixed terms of Commissioners, once appointed and confirmed by the Senate, to be generally independent of political affairs and regulated public utilities. Independence is important so that the commission will be able to discharge its functions effectively and fairly. As mentioned earlier, Commissioners are appointed on staggered six-year terms that provide some shelter from short term sometimes shifting political winds. The PUC has shown innovativeness and openness to deviating from traditional ratemaking to institute various elements of PBR and various incentive mechanisms as discussed above.

- **PUC can adapt to the changes in the regulatory environment**. The PUC has shown that it is ready and able to adapt to changes when necessary.

- **PUC Commissioners and staff are deeply knowledgeable about the issues**. This enables the Commissioners to adapt to changes and policy directives.

- **Public participation in the regulatory process is encouraged**. Public participation raises the public's confidence in the Commission. It also ensures that the Commission considers the issues that are important to the stakeholders in its decisions. As mentioned earlier and as part of its mission, the PUC should "address the goals and future needs of the State in the most economically, operationally, and environmentally sound manner."[158] In PUC's review of dockets, stakeholders are encouraged to express their standpoints, which serves

[158] Hawaii PUC. *Goals and Objectives of the Commission*. Website. <http://puc.hawaii.gov/about/goals-objectives/>. Access Date: March 2, 2018.

as a foundation for the PUC to balance considerations from different perspectives. Therefore, the Project team sees this as a strength of the current regulatory model.

- **Utilities are performing as expected in terms of providing reliable service**. The PUC had acknowledged this in Order 35411 when it stated that "utilities under the COS have successfully provided reliable service while affording regulated utilities a reasonable opportunity to ensure their financial integrity."[159]

- **Rates are set to allow the utilities to earn a fair return**. The utilities currently earn fair and reasonable returns as mentioned in their financial report. Moreover, the return on equity ("ROEs") authorized by the PUC to the utilities have historically been slightly above industry average at the time established, more recent authorizations have been slightly below the industry average.[160] The industry average was 9.99% in 2013 and 10.14% in 2012, according to Edison Electric Institute. The PUC authorized MECO, HECO, and HELCO, an ROE of 9% (in 2013), 10% (in 2012) and 10% (in 2012) respectively,[161] all slightly below the industry average, as shown in Figure 9.[162] In the current pending rate cases, HECO Companies requested an ROE of 10.60%, which is higher than the industry average requested ROE in 2016 and 2017 (Figure 9).[163] But the PUC has not issued a decision and order on these rate cases yet.

Figure 9. Comparing ROEs of HECO Companies and Industry Average

	HECO	HELCO	MECO	Industry Average
2012 (approved)	10.00%	10.00%	N/A	10.15%
2013 (approved)	N/A	N/A	9.00%	9.99%
2016 (requested)	10.60%	10.60%	N/A	10.43%
2017 (requested)	N/A	N/A	10.60%	10.27%

Source: S&P Global. EEI Rate Case Summary. Q4 2017.

- **Policies are in place to help in diversifying the State's energy portfolio**. Hawaii regulators and legislators have issued several regulatory orders and laws regarding clean energy goals for Hawaii, including the ambitious RPS goals, which pushes the market to diversify the energy portfolio. In addition, the PUC has made major progress on several dockets and issued orders to help achieve a diversified energy portfolio in Hawaii. The

159 Order No. 35411, at 11.

160 S&P Global Market Intelligence. *Commissions: Hawaii PUC*. Website. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4136041&Type=1&State=HI>. Access Date: March 2, 2018.

161 Ibid.

162 EEI. Edison Electric Institute's Rate Case Summary. 2012 and 2013.

163 Edison Electric Institute. *Rate Case Summary*. Q4 2017 Financial Update. Page 4.

related dockets include but not limited to *HECO Companies' Power Supply Improvement Plans ("PSIPs") (Docket No. 2014-01893), Distributed Energy Resource Policies Investigation (Docket No. 2014-0192)*, and *Community Based Renewable Energy Program (Docket No. 2015-0389)*, etc.[164] Moreover, the Hawaii PUC continues monitoring the implementation of the policies. Utilities are required to submit RPS reports to the PUC every year through 2021.[165] The PUC also approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii's RPS Law (HRS 269-91 to 269-95).[166]

Figure 10. Forecasted RPS and renewables (MW) by 2021

Island and County	Forecast RPS (%)	Forecasted Renewables (MW)
Molokai Island (Maui County)	142%	8.50
Hawaii Island (Hawaii County)	80%	235.30
Maui Island (Maui County)	63%	284.00
Lanai Island (Maui County)	59%	6.70
Oahu Island (Honolulu County)	45%	1,299.00

Source: HECO Companies. PSIP Update Report. December 23, 2016. Book 1, pages 6-11 to 6-21.

Having achieved 23.2% of the RPS target by 2015, the HECO Companies surpassed the state's 2015 RPS target of 15%.[167] According to HECO's PSIP, they expect to achieve the future RPS targets ahead of schedule, anticipating reaching 48% renewable energy target by 2020, 18% more than mandated by the state's RPS rules.[168] By 2021, each island is forecast to meet more than 40% of the RPS target as shown in Figure 10. The Puna Geothermal Venture ("PGV"), a geothermal power plant on the Hawaii island, was shut down in May 2018 due to the volcanic eruption of Kilauea.[169] Mayor Harry Kim authorized a permit for PGV to clear lava for a road to its site in December 2018, and the operators have started restoring road access to the property.[170] Moreover, in early January 2019, HECO Companies submitted contracts for seven grid-scale, solar-plus-storage

---

164 Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

165 Hawaii PUC. *Decision and Order No. 23912*. (Docket No. 2007-0008). Page 8.

166 Hawaii PUC. Order Relating to RPS Penalties. (Docket No. 2007-0008). Page 1.

167 Hawaiian Electric Company. "Record highs for renewable energy use in 2015." April 2016. <https://www.hawaiianelectric.com/Documents/my_account/customer_newsletter/hawaiian_electric/2016/hawaiian_electric_2016_04.pdf>

168 HECO. *PSIP Update Report*. December 23, 2016. Book 1, page 41.

169 HSEO. *Hawaii Energy Facts & Figures* (June 2018). Page 23.

170 Associated Press. "Work begins to restore access to lava-locked Puna Geothermal." December 13, 2018.

projects on Oahu, Maui, and Hawaii Island to the PUC for review. The projects will add approximately 262 MW of solar energy with 1,048 MWh of storage.[171]

Likewise, KIUC has exceeded the 2016 RPS goal of 30% by having 41.66% of its net electricity sales from renewable energy resources.[172] The RPS level in 2016 has also surpassed the 30% by 2020 RPS goal by 11.66% and the 40% goal by 2030 RPS requirement by 1.66%. Moreover, KIUC expects to reach 50% renewable in 2018 – five years ahead of the initial goal in Strategic Plan 2008-2023.[173] According to KIUC's 2016 Annual RPS Status Report, it is on target to exceed the next RPS requirement of 70% by 2040.[174] As of 2017, more than 44% of KIUC's electricity came from renewable energy sources.[175]

Therefore, the current regulatory model makes it possible for the utilities to comply with the requirements set by the PUC and are ahead in meeting the clean energy target.

- **Platforms are provided to the utilities to be able to leverage the state's position as an innovation test bed.** One of the state goals is to make Hawaii an innovation test bed. Under the current regulatory model, the utilities were provided with the opportunity to implement several innovative programs that use new energy solutions. For instance, in its Decision and Order No. 34924, the PUC approved two innovative programs for HECO Companies on October 20, 2017. The Smart Export program and the Customer Grid-Supply Plus ("CGS +") will expand opportunities for customers to install rooftop solar and battery energy storage systems.[176]

- **If designed correctly, the proposed PBR will be able to help achieve the goals set by the PUC.** As discussed earlier, the PUC has introduced a proceeding to investigate the PBR**.** PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[177] timely consumer benefits, lower administrative/regulatory costs, and greater compatibility with

---

[171] HECO. "New solar-plus-storage projects set low-price benchmark for renewable energy in Hawaii." January 3, 2019.

[172] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017.

[173] KIUC. *KIUC Board Sets Renewable Energy Goal of 70 percent by 2030*. February 1, 2017.

[174] KIUC. "Docket No. 2007-008 - In the Matter of Public Utilities Commission Instituting a Proceeding to Examine Hawaii's Renewable Portfolio Standards Law, Hawaii Revised Statutes ("HRS") §§ 269-91 — 269-95, as Amended by Act 162, Session Laws of Hawaii 2006: Kauai Island Utility Cooperative's ("KIUC's") 2015 Annual Renewable Portfolio Standards ("RPS") Status Report." April 11, 2017

[175] KIUC. *KIUC's 2017 Annual Renewable Portfolio Standards ("RPS") Status Report*. March 29, 2018.

[176] Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

[177] Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

a rapidly changing industry. PBR can also provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[178] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers. Nevertheless, the devil is in the detail.

4.2 Areas of improvements in the current regulatory model

Under the current regulatory model, there are several potential improvements that can be made. These include providing incentives in utilities' performance, providing certainty with regards to timeline on issuing regulatory decisions, reducing complexity and cost of regulation and regulatory compliance and mitigate risks in the establishment of the final design of the Performance-Based Regulation ("PBR").

- **Most of the current performance metrics are for tracking only**. As mentioned earlier, only a few of the performance standards have any rewards or penalties set. With the implementation of the PBR, it is important to establish performance standards along with efficiency incentives to ensure that any cost reductions implemented by the utility will not cause a deterioration in service quality. When properly designed, performance standards should ideally meet a variety of different objectives such as aligning incentives by offering financial rewards for service level improvements, ensuring a high level of service and protect consumers from hidden costs increases and poor service quality, and allowing corrective measures, to name a few. Standards must be attainable, measurable, and verifiable, and must be consistent with customer needs or expectations and what customers are paying for. However, setting the criteria and financial incentives (or penalties) for performance requires additional administration and management.

- **Regulatory proceedings sometimes take longer than nine months.** Uncertainty over when the Commission issues its decision puts the utilities at a disadvantage when conducting business. Currently, as discussed above, in rate cases the law states that PUC has nine months from the time that the filing was made. However, for the past ten years, it has taken the PUC between 7 months and 31 months to decide on rate cases as shown in Figure 11.

- **Increasing complexity and cost of regulation and regulatory compliance**. The regulatory framework, which was already time-consuming and complex under traditional COS regulation, is further increasing in complexity with decoupling and various elements of PBR already having been established and implemented and will continue to increase in complexity as the Ratepayer Protection Act is implemented and the PBR Docket proceeding establishes additional PBR mechanisms. The complexity increases costs of the PUC and the Consumer Advocate, and increases costs for electric utilities, which passes on such costs to its ratepayers. Minimizing complexity may seem

[178] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

at odds with other initiatives, but consideration should be given to reducing or at least minimizing the increase in complexity of regulation and regulatory compliance.

Figure 11. Number of months to decide a rate case (2009-2017)

Utility	*Docket*	*Date filed*	*Date decision was filed*	*Decision Type*	*Rate Case Duration (months)*
Hawaii Electric Light Co	D-2012-0099	8/16/2012	3/19/2013	Settled	7
Hawaii Electric Light Co	D-2009-0164	12/9/2009	4/4/2012	Settled	28
Hawaiian Electric Co.	D-2013-0373	6/27/2014	12/23/2016	Fully Litigated	30
Hawaiian Electric Co.	D-2010-0080	7/30/2010	6/29/2012	Settled	23
Maui Electric Company Ltd	D-2014-0318	12/30/2014	8/4/2017	Fully Litigated	31
Maui Electric Company Ltd	D-2011-0092	7/22/2011	5/31/2013	Settled	22
Maui Electric Company Ltd	D-2009-0163	9/30/2009	5/2/2012	Settled	31

- **Other elements in the PBR should be considered in the final design.** Order No. 35411 discusses the PBR mechanisms that the PUC hopes to achieve which included greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks between utilities and customers and fulfillment of state policy goals, as mentioned in Section 3.5. The discussion was focused heavily on revenue adjustment mechanisms and performance incentive mechanisms. The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[179] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting on the side of the utilities can also lead to potential additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts can significantly deviate from actual figures so the PBR design must include mechanisms that will provide a degree of protection to both the shareholders and ratepayers.

  These mechanisms may include re-openers/offramps, true-ups, and exogeneous factors ("Z-factors"). [180] Re-openers provide a degree of protection to both the shareholders and ratepayers. They provide utilities a way to modify the ratemaking mechanism before the end of the regulatory term or exit out of the regulatory regime if certain exceptional

[179] Items to forecasts include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

[180] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

circumstances materialize. During the review period of the PBR proposal, events or criteria are defined that will trigger an off-ramp event.

True-ups adjust rates between rate cases based upon the over or under-recovery of target revenues. True-ups arise due to three potential reasons: (i) operating costs differed from the forecast, volumes/customers differed from forecasts, or (iii) collection and bad debt expense rose. Timing of true-up is important; the less frequently it occurs, the more important it is to factor in the cost of capital, whether payments are to utility from customers or vice versa.

Z-factor is a mechanism to recoup extraordinary costs that are outside the utility's ability to control and is not included in the current escalation formula. It can either be defined by specific events or can be broader and include events which meet pre-established criteria.

5 Appendix A: Scope of work to which this deliverable responds

Task 2.1.2 General assessment of the existing regulatory model in place in Hawaii, including strengths and weaknesses.

CONTRACTOR shall provide a general assessment of the existing regulatory model in place in Hawaii.

DELIVERABLE FOR TASK 2.1.2. CONTRACTOR shall provide its conclusions and all work related to an assessment of the existing regulatory model in Hawaii. CONTRACTOR shall provide an MS Word document describing strengths and weaknesses of the current model, with an emphasis on how the current model performs related to policy goals for the electricity sector espoused by the administration. CONTRACTOR shall submit deliverable for TASK 2.1.2 to the STATE for approval.

6 Appendix B: List of works consulted

Administrative Rules. Chapter 6-60-4 – Standards for Electric and Gas Utility Service.

DEBDT's reply to LEI's question. Schwing, Michael D. RE: Key priorities of a regulatory model. Sent: Monday, February 26, 2018 1:48 PM.

DSIRE. Interconnection Standards – Hawaii. Website. <http://programs.dsireusa.org/system/program/detail/989>. Access Date: February 16, 2018.

Edison Electric Institute. *Rate Case Summary*. Q4 2017 Financial Update.

EIA. *Today in Energy*. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: March 22, 2018.

ERCOT. *Company profile - History*. Website. <http://www.ercot.com/about/profile/history>. Access Date: April 2, 2018.

FERC. Regional Transmission Organizations (Issued December 20, 1999) (Docket No. RM99-2-000; Order No. 2000), page 151.

Guernsey. *County of Maui: Analysis of Alternative Forms of Ownership and Alternative Business Models for Maui County's Electric Utility Company*. December 23, 2015.

Hawaii House Bill 2525 (2012).

Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015)

Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

Hawaii PUC. *Goals and Objectives of the Commission*. Website. <http://puc.hawaii.gov/about/goals-objectives/>. Access Date: March 2, 2018.

Hawaii PUC. *Order No. 30371 Relating to Various Matters in RSWG Process (Docket No. 2011-0206)*. Page 17.

Hawaii PUC. *Order No. 32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule* (Docket No. 2013-0141). Page 9-10.

Hawaii PUC. *Order No. 35075 Providing the Attached Amendments to the Performance Incentive Mechanism and Revenue Balancing Account Tariffs Proposed by the Hawaiian Electric Companies* (Docket No. 2013-0141). Effective January 1, 2018.

Hawaii PUC. *Service Quality Reliability Annual Reports*. Website. <http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/>. Access Date: February 16, 2018.

Hawaii Revised Statues (“HRS”) Chapter 269 – Public Utilities Commission

Hawaii State Energy Office. State of Hawaii – Energy Policy Directives. Website. <http://energy.hawaii.gov/energypolicy>. Access Date: March 2, 2018.

HECO Companies. Decoupling Brochure. Website. <https://www.hawaiianelectric.com/Documents/my_account/decoupling/decoupling_brochure.pdf>. Access Date: February 16, 2018.

HECO Companies. *Rule 14 H – Consistency with IEEE Standards*. Website. <https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rules/14.pdf>. PDF Page 12.

HECO. *Key Performance Metrics*. Website. <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>. Access Date: February 16, 2018.

HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. http://energy.hawaii.gov/energypolicy.

House of Representatives. State of Hawaii. HB 623. Effective July 1, 2015.

KIUC. KIUC Interconnection Process. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/Full%20Application%20Packet.pdf>. Access Date: February 16, 2018.

KIUC. *Tariffs*. Website. <http://website.kiuc.coop/content/tariffs>. Access Date: February 16, 2018.

Mayor’s Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui*. August 25, 2017.

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014).

Reliability Standards Working Group Independent Facilitator’s Submittal: Final Report and Certificate of Service. March 13, 2013. Page 4-5.

S&P Global Market Intelligence. *Commissions: Hawaii PUC*. Website. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4136041&Type=1&State=HI>. Access Date: March 2, 2018.

Stakeholders' comments on regulatory models in the stakeholders' engagement process, including during the kick-off meeting in May 2017, VERGE Hawaii conference in June 2017, and community meetings in October 2017.

US EIA. *State Profile and Energy Estimates: Hawaii*. Website. < https://www.eia.gov/state/analysis.php?sid=HI>. Access Date: March 1, 2018.

Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals

A working paper prepared by London Economics International LLC with support from Meister Consultants Group for the State of Hawaii

August 16, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document is one of several working papers associated with that engagement. Five utility regulatory structures were reviewed in more detail based on the team's preliminary evaluation of various potential regulatory arrangements: (i) status quo, (ii) status quo with increased oversight, (iii) independent system operator, (iv) distribution-focused regulatory model, and (v) performance-based regulation ("PBR") model. Key differences among these models include varying regulatory oversight over different sectors of the electricity value chain and the role of utilities in owning and operating the assets. Our preliminary evaluation of these regulatory models shows that the PBR model scores highest while the status quo performs the least favorably across the six criteria (including the five listed in the State legislation directing this research) considered: (i) the ability to facilitate the achievement of state energy goals; (ii) adequacy of mechanisms that can maximize consumer cost savings; (iii) relevance of arrangements towards a competitive distribution system; (iv) availability of features that minimizes or addresses conflicts of interest; (v) availability of innovative approaches that align stakeholder interests; and (vi) inherent process that help reduce transition costs.

The Project Team also notes that:

- *a hybrid model with a combination of some of these models could be more effective in achieving all the State's goals than any single regulatory model on its own;*
- *a reduced Public Utilities Commission ("PUC") oversight model is worthy of consideration for Kauai County.*

Table of Contents

Table of Figures

List of acronyms

AMI	Advanced Metering Infrastructure
CAPM	Capital Asset Pricing Model
CGS +	Customer Grid-Supply Plus
COS	Cost of Service
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Hawaii Division of Consumer Advocacy
DCF	Discounted Cash Flow
DG	Distributed Generation
DER	Distributed Energy Resource
DSO	Distributed System Operator
DSPP	Distributed System Platform Provider
DUOS	Distribution use of the system
EAM	Earning Adjustment Mechanism
ECAC	Energy Cost Adjustment Clause
EIA	US Energy Information Administration
EMA	Electricity Market Authority
ERC	Energy Resources Coordinator
ERCOT	Electric Reliability Council of Texas
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statutes
HSEO	Hawaii State Energy Office
IDSO	Independent Distribution System Operator
IOU	Investor-Owned Utility

IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NTA	Non-Transmission Alternative
NWA	Non-Wires Alternative
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PPAC	Purchased Power Adjustment Clause
PSIPs	Power Supply Improvement Plans
PUC	Hawaii Public Utilities Commission
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account
REV	Reforming the Energy Vision
ROE	Return on Equity
RPS	Renewable portfolio standards
RTO	Regional transmission organization
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TIER	Times Interest Earned Ratio
TIS	Texas Interconnected System
TOU	Time of Use
TTC	Total transmission capacity
UK	United Kingdom
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.2.1 in the project scope of work, provides a high-level evaluation of the selected regulatory models relative to the State's goals. Those goals, enshrined in the legislation authorizing this research, are shown in the textbox below.[1] The Project Team also evaluated the strengths and weaknesses of the existing regulatory model in Hawaii to contextualize the discussion of whether other regulatory models address improvements needed (if any) in the current model.

Five utility regulatory structures were selected following the Project Team's evaluation of various additional potential regulatory arrangements, with a specific focus on relevance to the needs of Hawaii. These include:

- status quo;
- status quo with increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model; and
- performance-based regulatory ("PBR") model.[2]

These models differ in terms of regulatory oversight over different segments of the electricity value chain in each model, the role of utilities in planning functions and at the distribution level, and the relative importance of varying revenue generation streams for the utilities. The PBR model introduces additional incentives and penalties on top of existing revenue streams. A distribution-focused model could create other earning opportunities for the utilities. However, the ownership and fundamental business model of the utilities is assumed to remain the same under all regulatory models.

State's key criteria in evaluating models based on the legislation

- Achieve State energy goals
- Maximize consumer cost savings
- Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs
- Eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation

Source: House Bill No. 1700 Relating to the State Budget

Except for the status quo, each of the other regulatory models would require a series of actions to implement. Some of these models would need the issuance of rules or Orders by the PUC to initiate the establishment of a new entity or define a new structure. Subsequent steps common to several of the potential regulatory forms include the development of a surcharge to support the

[1] Hawaii State Legislature. *House Bill No. 1700 Relating to the State Budget.* June 24, 2016.

[2] As discussed in Task 2.1.1., we have three variants of PBR for Hawaii, namely (i) Light PBR, (ii) Conventional PBR, and Outcomes-based PBR.

operation of the new entity, hiring of new staff and experts for the new entity, and assumption of new roles, to name a few.

Based on our high-level qualitative and preliminary evaluation of the regulatory models relative to the State's goals, we find that the PBR model is best positioned to address the State's priorities. It received the highest rating in three of six criteria and second highest rating in another criterion. The expected performance of other models varied substantially; the status quo regulatory model received the lowest assessment overall.

It should be noted that these models are not mutually exclusive and may be combined. The Project Team also evaluated potential hybrid models--(i) combining a variant of PBR with a HERA entity with modified functions; and (ii) combining PBR with the distribution-focused regulatory model. Based on our analysis, we found these two models to be potentially more effective in meeting the State's criteria than some of the stand-alone regulatory models. The Project Team also considered a reduced oversight model for Kauai County because it has a different utility ownership structure than the other counties. Preliminary analyses indicated both the advantages and disadvantages of this regulatory model, making it worthy of more in-depth analysis in future deliverables.

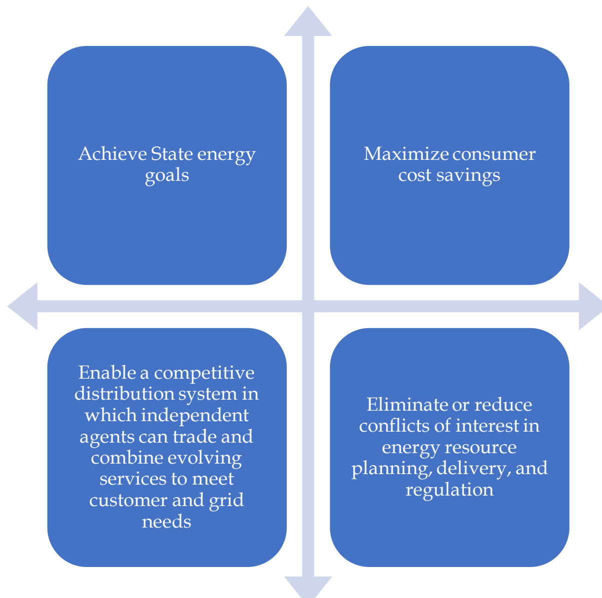
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The project aims to evaluate the ability of each model to achieve the State's key criteria[5] (Figure 1).

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. Moreover, it will also aid in identifying the process required in forming such ownership and regulatory models as well as in determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy

---

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Relevance of this deliverable relative to others in the project

This deliverable is responsive to Task 2.2.1 in the project scope of work. It introduces the various types of regulatory models and evaluates their characteristics. It also summarizes a comparison of the regulatory models from Hawaii's perspective, assesses the existing regulatory model in place in Hawaii, and provides a high-level process assessment.

Moreover, various aspects of the regulatory models will be further explored in subsequent deliverables. This includes:

- assessment of current markets under each regulatory model, including a case study, analysis, and conclusions (Task 2.2.2);
- high-level assessment of the technical, financial, and legal feasibility of each regulatory model (Task 2.2.3);
- summary analysis and conclusions related to estimating stranded costs for each regulatory model (Task 2.2.4);
- soliciting public input from each island currently served by an electric utility on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5);
- identification of and recommendations for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, if there would be a change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each recommended model impacts State agencies staffing and stakeholders (Task 2.3.4);
- estimation of potential of each model in increasing distributed energy resources (Task 2.4.1); and
- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms for each regulatory model (Task 2.5).

[6] Hawaii Contract No. 65595. Scope of Services.

2.3 Future refinements

As noted earlier, this deliverable is intended to serve as an introduction to the different regulatory models and, as such, the results of our analysis are subject to further refinement and changes as the project moves forward and inputs from stakeholder groups and results of quantitative analysis and case studies become available. LEI will provide case studies in some of the deliverables (if applicable) to highlight the essential features of the different regulatory models and key issues and lessons from other jurisdictions or utilities. Furthermore, the project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[7]

[7] A series of community meetings across the State were held in June 2018 in Hawaii. The workshops provided opportunities for the attendees, as well as online participants, to hear from key stakeholders in the energy policy discussion and provide inputs to the study through small group discussions.

3 Similarities and differences of the regulatory models

As introduced in Task 2.1.1, five regulatory models are being considered in this evaluation. These models are not mutually exclusive, and some of these models and/or their features could co-exist. These regulatory structures were determined based on legislative mandates (such as the Hawaii Electricity Reliability Administrator ("HERA") and the ongoing PBR proceeding), the emerging market trends in high renewables penetration jurisdiction, current state goals, and our high-level evaluation of various additional potential regulatory arrangements. The six selected regulatory models[8] are listed below:

1. status quo;
2. status quo with increased oversight ("the HERA model");
3. independent system operator ("ISO");
4. distribution-focused regulatory model; and
5. performance-based regulation ("PBR") model.

Furthermore, the Project Team determined three potential PBR models suitable to Hawaii. As discussed in Task 2.1.1, PBR is not a single type of regulatory regime but comprises various mechanisms and combinations. The three PBR variants are:

1. Light PBR;
2. Conventional PBR; and
3. Outcome-based PBR.

Each of these models entails a different approach to regulating entities in the Hawaii power sector. Some of these regulatory models (such as the HERA model, ISO, and distribution-focused regulatory model) require delegating some of the responsibilities of the Public Utilities Commission ("PUC") to an independent entity, while others such as the PBR would require modified oversight from the PUC. This section describes the regulatory models, focusing on their similarities and differences. The Project Team reviewed the regulatory models across three (3) key parameters to ensure coherence and consistency:

- ***utility's role across the value chain***: the role of the utilities in the regulatory model in each step of the value chain—including generation, system operator, transmission, and distribution. More specifically, we will consider whether the utilities will own and operate the assets and perform the planning or will there be an independent entity that will take over some of the responsibilities of the utilities.

---

[8] A lighter regulation for KIUC was also assessed in Section 7.

- ***utility's motivation:*** we will determine what incentives or disincentives will each regulatory model provide a utility, particularly, vis-à-vis its decision-making in investments in capital expenditure vs. operations and maintenance ("O&M") or in aligning its goals with the State's goals;

- ***oversight and monitoring:*** we will evaluate how will the oversight responsibilities of the Commission change across the energy value chain and if some of the current duties of the PUC will be passed on to another entity and if so, how will changes ensure effective monitoring.

Figure 2 shows a summary of the similarities and differences of the models (based on the recommended parameters), with relevant components described in greater detail below.

Figure 2. Similarities and differences of the regulatory models

	Status Quo	Status quo with increased oversight	ISO	Distribution-focused regulation	PBR
Utility role across value chain					
Asset ownership	X	X	X	X	X
Asset operation	X	X	X	X	X
Investment planning and execution	X				
Utility motivation					
Incentive to increase/decrease spending	X				
Incentive to increase/decrease investment	X				
Maintain operational control	X	X			X
Regulated revenues in ratebase	X	X	X	X	X
Market-based revenues			X	X	
Oversight and monitoring					
PUC	X	X	X	X	X
Independent monitor		X	X	X	

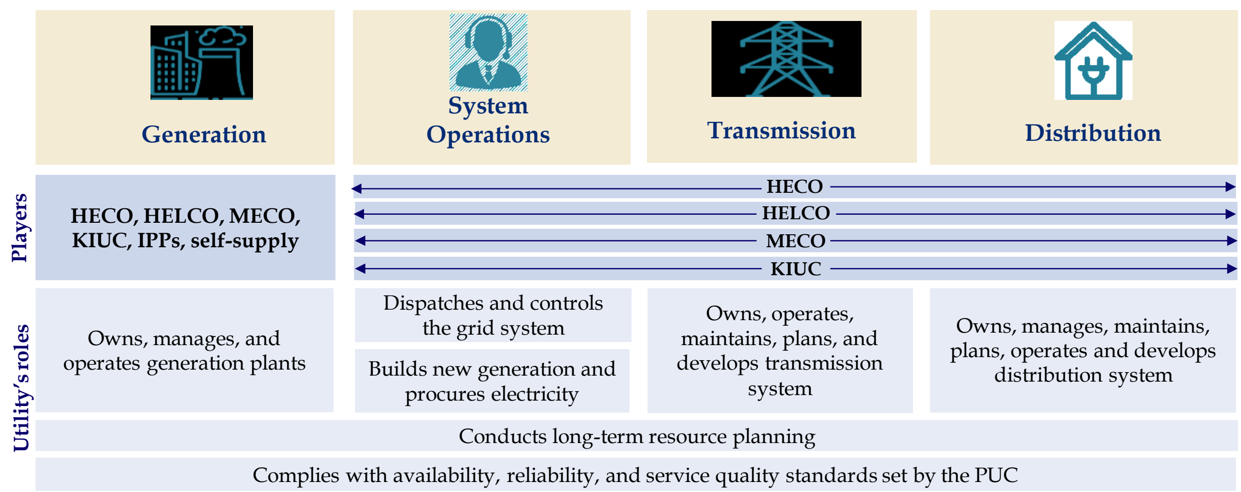
Note: "X" indicates that the feature is present in the model. PBR captures all three variants described in Task 2.1.1 – their similarities and differences in terms of the categories in the table above are identical.

3.1 Utility's role across the value chain

The utility's role across the value chain differs slightly in each of the regulatory models depending on the structure of the energy sector, but in no case does the utility disappear. As discussed in Task 2.1.2, some of the key roles of the utilities in Hawaii are shown in Figure 3.

Both the status quo and PBR regulatory models maintain the existing structure, where the HECO Companies and KIUC are vertically integrated and regulated by the Commission.[9] Under these models, the utilities are the major generators as well as owners and operators of transmission and distribution assets in their respective service areas. Investment planning and plan execution are performed by the utilities themselves, with approval from the Commission. The significant difference lies in the approach to the setting of utility rates and returns by the Commission. The utilities will continue to be under a cost-of-service ("COS") approach under the status quo while the Commission will apply a Hawaii-specific PBR mechanism under the PBR model.

Figure 3. Current key roles of the utilities across the value chain



Under the HERA model, the existing regulatory model is augmented with the creation of HERA. The utilities will maintain their current roles (i.e., generation, transmission, and distribution) across the electricity supply value chain. However, the utilities will be required to meet increased reliability and open access requirements, under the oversight of HERA. Investment planning and execution may also be subject to increased scrutiny from HERA. As discussed in Task 2.1.1, a Light HERA model requires the creation of an administrative body, which functions as an ombudsman and appeals body. Figure 4 shows the additional task of the utility under this model.

Meanwhile, under the ISO regulatory model, the newly-formed ISO either acquires or leases the transmission control and monitoring assets of the utilities. The utilities retain ownership over the transmission assets and control and ownership of the distribution system. In this model, the ISO conducts transmission planning studies along with the utilities. Upon approval of the PUC, the utilities will implement the plan and invest in and maintain the transmission facilities. The incumbent utilities' generation business may be retained or spun off into a subsidiary whose focus is on participating in the wholesale market. Figure 5 illustrates the roles of the ISO and utilities under an ISO model.

[9] The existing regulatory model in Hawaii is evaluated in detail in Task 2.1.2, where the team provides an overview and general assessment of the existing regulatory model.

Figure 4. Key roles of the utilities across the value chain under a Hawaii HERA model

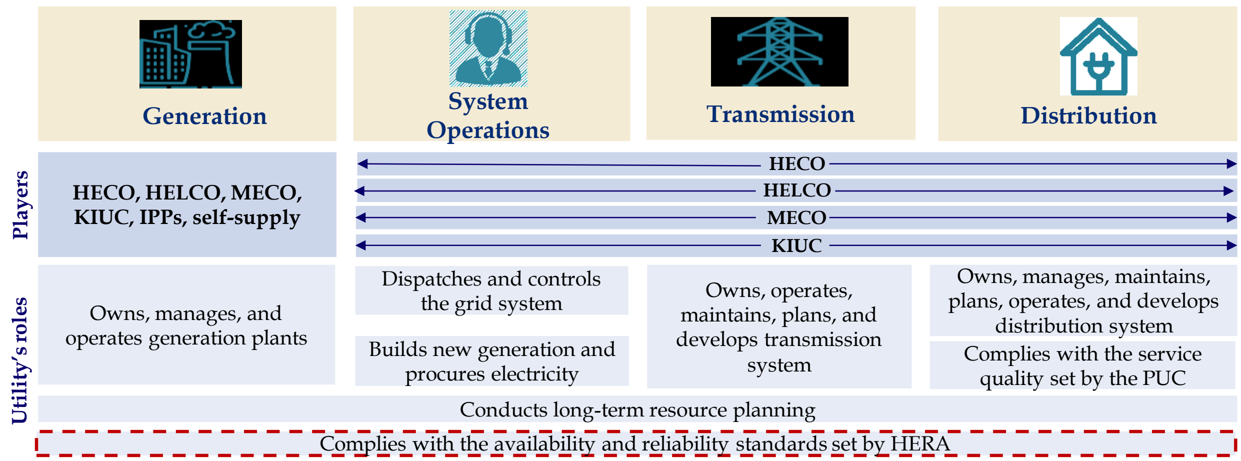
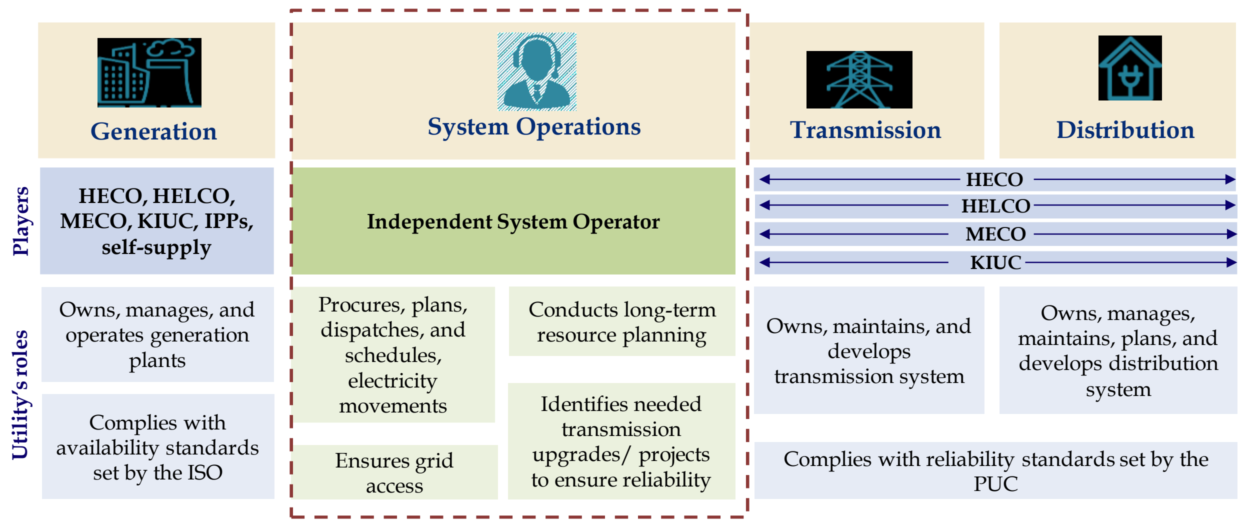


Figure 5. Key roles of the utilities across the value chain under ISO model

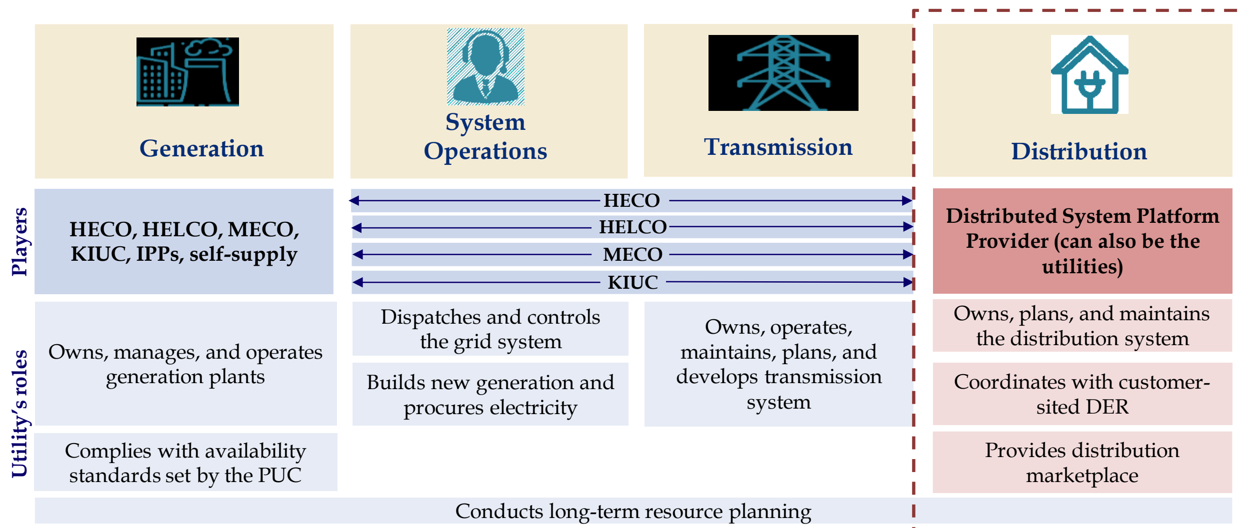


Under the distribution-focused regulatory model, the utilities facilitate the integration of distributed energy resources ("DER") into the grid. Ownership and control of utility-scale generation and transmission assets remain with the utilities in this model. The primary difference of this model relative to the first two described above is in the low-voltage distribution grid, where the utility is encouraged to provide distributed system platform services to enable third-party DER providers to create value for both customers and the system itself.[10] In this regulatory model (where investment planning and execution are carried out by the utilities), the Commission may also mandate the creation of a Distribution System Operator ("DSO"), which would perform the same duties as an ISO essentially but focused on the distribution-level

[10] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

system.[11] The utilities still own the distribution assets, but the operations of the distribution grid will be handled by the DSO in this regulatory model. Figure 6 depicts the roles of the utilities under the distributed-focused regulatory model.

Figure 6. Key roles of the utilities across the value chain under the distributed-focused regulatory model (DSSP)



3.2 Utility's motivation

The **motivation of the utility** can be derived by analyzing the incentives or disincentives created by the model, particularly utilities' investment decisions and the alignment of their goals to the achievement of the State's goals.

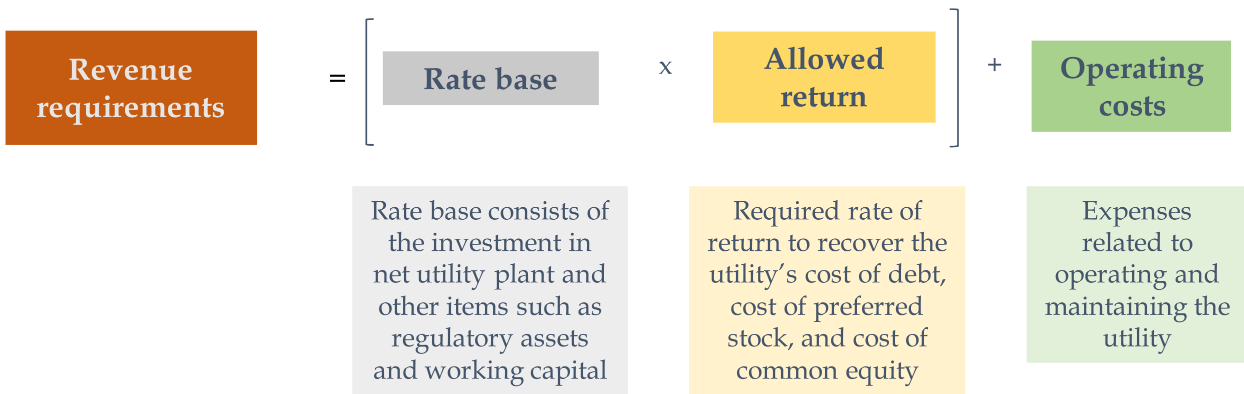
Under all the selected regulatory models (except for PBR), most or all of the sectors of the value chain will still be under the rate base or COS approach. Therefore, there is an inherent bias in spending more on capital infrastructure instead of operations and maintenance. This is because of the revenue requirement formula where the rate base—which includes capital investment—is multiplied by the rate of return whereas operating costs are not multiplied by the allowed return. Therefore, this formula provides a strong incentive for the utility to prioritize capital projects (Figure 7).

The proposed PBR regime in Hawaii aims to have no distinction between capital and operating expenditure in their revenue requirements. In the PUC order opening the PBR proceeding in Hawaii, it indicated that the proposed PBR regulatory model should encourage exemplary utility performance, saying that "*…PBR frameworks should result in an incentive structure that encourages exemplary utility performance irrespective of the nature of its investments (e.g., investment in capital*

[11] Ibid.

expenditures versus investment in efficiency measures).”[12] Therefore, under the proposed PBR, the utilities will not be biased toward capital expenditure. However, the PBR model can be implemented in conjunction with other proposed regulatory models and does not need to be a stand-alone option.

Figure 7. Revenue requirements formula



Under the ISO and independent DSO models, the utilities would still own and rate base their transmission and distribution assets and pass the transmission planning and dispatch to the ISO or the distribution planning to the DSO. Since independent entities (e.g., ISO and DSO) conduct the system planning through a stakeholder process (that involves utilities) and recommend the selected investments to the PUC, conflict of interest over investment decisions is reduced. Therefore, utilities have less influence on whether an investment is made—guarding against their incentives to over-capitalize the system, in the process.

3.3 Oversight and monitoring

As discussed in Task 2.1.2, the PUC’s key responsibilities include approval of rates, fuel supply contracts, power purchase agreements, new generation builds, and resource planning as well as monitoring performance standards, reliability, and grid access, to name a few (Figure 8).

The role of the PUC changes slightly under HERA model. More specifically, the HERA entity, which will be responsible to the PUC, will oversee the reliability and grid access functions. The PUC will maintain its other responsibilities such as the approval of rates and large capital expenditure (Figure 9).

[12] Hawaii Public Utilities Commission. *Order No. 35411: Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018.

Figure 8. Current key oversight responsibilities of the PUC

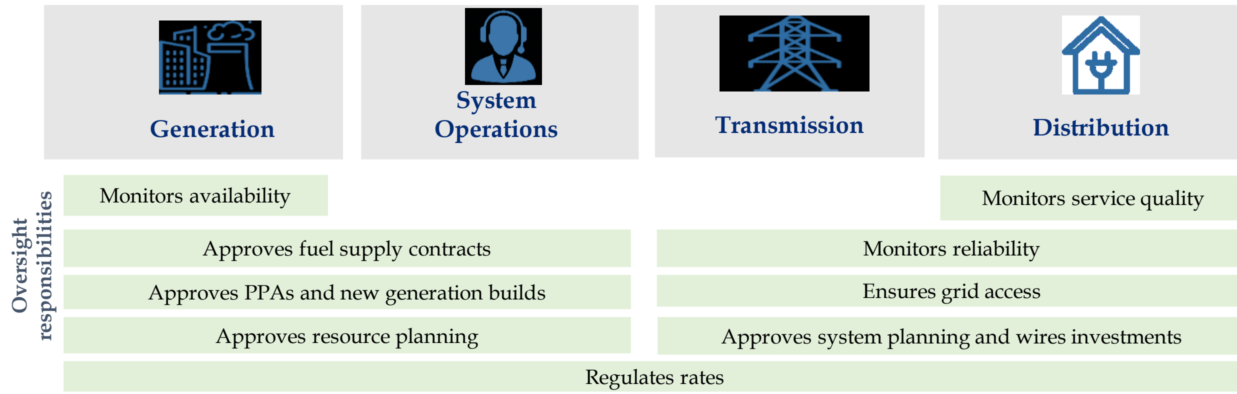
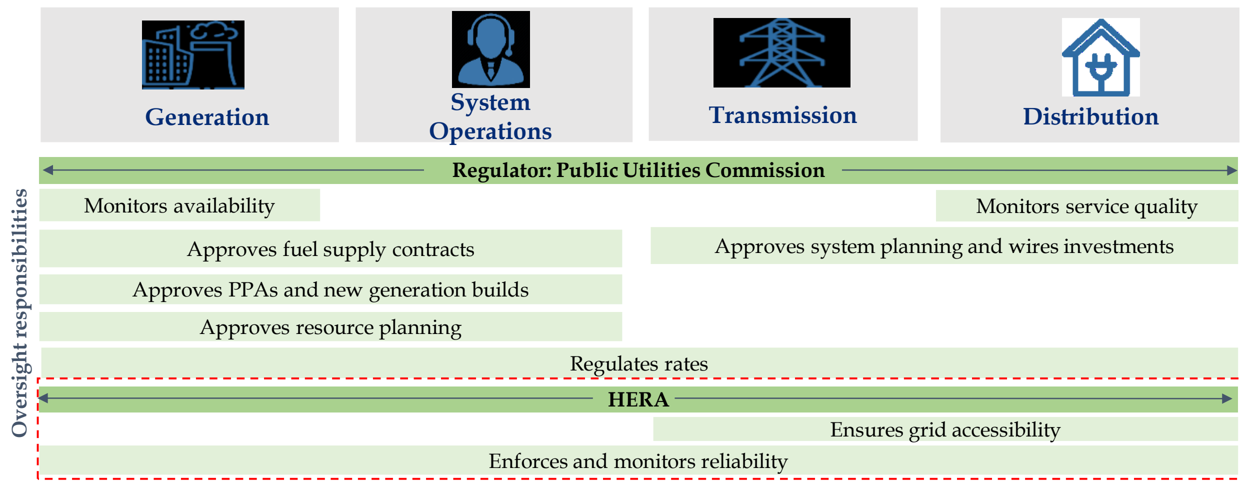


Figure 9. Key oversight responsibilities of the PUC under the HERA model



In the ISO and distribution-focused model, monitoring and oversight occur across multiple entities, with the Commission delegating market monitoring and competition assessment to the newly created entities. With the ISO model, the Commission's role in system planning and coordination is taken up by the new entity, with the ISO further responsible for short-term reliability and system operation. In the case of the distribution-focused model in Hawaii, the distribution-level planning, coordination, and oversight are also combined with the bulk power system. The smaller size of Hawaii's electric grid (especially in terms of transmission infrastructure) compared to mainland interconnections, makes it possible for the DSO to oversee both the transmission and distribution operations. In other words, the roles of the ISO and DSO can be performed by one independent entity. The regulator's role may be limited to the approval of capital expenditure, resource plans, and contracts, and management and resolution of disputes.

Finally, PBR requires the PUC—in addition to its current responsibilities—to develop new PBR mechanism and determine targets and metrics in assessing utilities' performance (under the new framework) and from there, come up with a system of rewards and penalties. This leads to the additional role of the PUC under a PBR regime: monitoring the performance of utilities vis-à-vis the set targets and outcomes.

4 Advantages and disadvantages of each regulatory model

This section provides a high-level overview of the potential benefits and drawbacks of each regulatory model. The analysis considers these advantages and drawbacks from the perspective of the utility, the Commission, and ratepayers. A summary of the advantages and disadvantages of each regulatory model is illustrated in Figure 10 and are discussed in more detail in the following subsections.

Figure 10. Summary of advantages and disadvantages of each regulatory model

Regulatory Model	Advantages	Disadvantages
Status quo	Innovative and openness of PUC Participatory regulatory process raising public confidence in Commission and its decisions Existing framework allows utilities to earn a reasonable return	Limited incentives for utility performance Uncertainty with regards to timing of regulatory decisions Complexity and cost of regulatory compliance
Status quo with increased oversight (HERA)	Enforcement of open access and reliability standards Long-term view of reliability needs Recommend specific reliability standards relevant to Hawaii context Can develop into a center of excellence, expertise and best practices	Risk of ambiguity of roles between Commission and new entity Increased cost of HERA to fall on ratepayers
Independent System Operator ("ISO")	Efficiency gains of competition in the power supply market can lower costs to consumers and eliminate subsidies Additional benefits, such as improved reliability, better coordination, and reduced transaction costs	Technically complicated and requires highly-specialized staff High level of stakeholder engagement required to initiate Careful market design needed to mitigate implementation risk
Distribution-focused regulatory model	Potential for lowering costs to consumers as they shift consumption during peak hours via DERs Market efficiencies from increased competition of DER solutions Optimizing of environmental benefits of DERs in the system Potential to reduce grid costs through non-wire alternatives	Stranded cost risk exists which would be borne by consumers Technical complexity presents risk of high cost of implementation Extensive levels of consumer education required to optimize market participation Few best practices to learn from
Performance-based regulation ("PBR")	Drives innovation and better investment decisions Efficiency gains from PBR mechanisms can be shared with customers Incentive for utilities to operate more efficiently	Significant regulatory work may be required Requires lengthy stakeholdering efforts

4.1 Status Quo

The status quo represents the existing regulatory model in Hawaii.[13] The State government (Legislature and Governor) establishes energy policies through legislative enactments and resolutions that are further developed, implemented, and enforced by the PUC. The Hawaii State Energy Office ("HSEO") within the Department of Business Economic Development & Tourism ("DBEDT") assists in developing and implementing energy policy as may be provided by the State.

As mentioned earlier, electricity rates for the HECO Companies are generally determined through a COS approach (sometimes referred to as "rate return regulation") with some components associated with performance-based regulation such as the earning sharing mechanisms, penalties for non-achievement of specific performance standards (mostly in reliability), and a multi-year rate plan. Task 2.1.2 discusses the current regulatory model in Hawaii in detail.

4.1.1 Advantages

As discussed in Task 2.1.2, the current regulatory model has several strengths including the PUC's ***independence and innovativeness***, as reflected in its openness to deviation from traditional ratemaking by instituting various elements of PBR and incentive mechanisms; a ***participatory regulatory process*** that raises the public's confidence in the Commission; a model that allows rates to be set, allowing utilities a ***reasonable rate of return***; and presence and implementation of policies that support the diversification in the State's energy portfolio.

4.1.2 Drawbacks

However, there are a number of potential improvements that can be made in the current regulatory model. These include the need to provide incentives that will encourage superior utility performance on specific metrics, provide certainty with regards to timeline on issuing regulatory decisions, and reduce complexity and cost of regulation and regulatory compliance.

4.2 Status Quo with increased oversight – the HERA model

As discussed earlier, the HERA is assumed to be implemented under the status quo with increased oversight model ("HERA model"). The HERA as an entity was established by the Hawaii State legislation (Act 166) in 2012 although there is currently no HERA entity in place as of this writing.

The increased oversight from HERA would not change the current structure of the electricity value chain. Utilities would continue to operate the transmission and distribution network under this regulatory model. Nevertheless, the PUC's role in ensuring grid access and reliability would

[13] A comprehensive assessment of the existing regulatory model in Hawaii is detailed in Task 2.1.2, where the Project Team reviews the energy industry, the rulemaking process, the ratemaking process and undertakes a general assessment of the strengths and weaknesses of the existing regulatory model.

be transferred to HERA in this regulatory model. As mentioned earlier, the Project Team is also analyzing a Light HERA option.

4.2.1 Advantages

Having a separate entity—that performs oversight and monitoring of interconnection and reliability standards—from the Commission allows ***more stringent enforcement*** of technical and reliability standards as well as a ***streamlined, transparent, and standardized interconnection process***. An independent entity that reports to the Commission on reliability standards is likely to take a ***long-term view*** on reliability needs for each county and recommend ***specific technical and reliability standards*** as counties seek to meet the renewable portfolio standards ("RPS") targets for the State.

Moreover, a HERA would ensure a fair and transparent interconnection process. HERA is expected to safeguard system reliability, resiliency, and accountability. It will also recommend specific reliability standards relevant to Hawaii context, given the unique features of the State.

Moreover, the HERA—as a separate entity dedicated to reliability standards monitoring and enforcement—can develop into a ***center of excellence, expertise, and best practices*** with regards to distributed energy resources integration. This is provided by the legislation, which allows the Commission discretion as to the specific roles that HERA can play. With such a purpose, HERA should provide training and technical assistance to counties and utilities seeking to comply with the State's RPS goals and reliability targets.

Finally, a study—commissioned by the Mayor's Office of Economic Development of Maui County (August 2017)—assessed the initial structure for HERA.[14] The study found that an independent organization such as HERA could be beneficial to the State particularly when it comes to overseeing planning, reliability standards, and interconnection processes.

A variant of this model, a Light HERA, could be designed to improve DER interconnection process as well as ***provide an independent assessment of the impact of DERs on local reliability***. Its narrow scope would allow the entity to develop stronger expertise on DER interconnection and hosting capacity analysis than a body like the PUC, which has more wide-ranging responsibilities. Moreover, the expertise would add more weight to its decisions as an ombudsman in dispute resolution. Having a separate entity that oversees these functions would accelerate DER interconnections as well as the resolution of disputes that usually take months under current PUC regulatory proceedings. Furthermore, a streamlined body has lower overhead costs and is less likely to create overlapping layers of jurisdiction and bureaucracy.

4.2.2 Drawbacks

However, a HERA model faces the ***risk of overlap*** of roles between the Commission and the new entity. Currently, the Commission is responsible for enforcement of reliability standards across

---

[14] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017.

the State. The establishment of HERA would require the Commission to define the mandate of the new entity and potentially transfer this role to HERA, with the new entity reporting back to the Commission on its activities for the preceding year on an annual basis.[15]

Another potential challenge in the establishment of a HERA entity is the required ***funding***—which would ultimately fall on ratepayers.[16] The surcharge implemented to fund the HERA entity would be recoverable from ratepayers and, by definition, increases rates (with all other costs staying the same). In the Maui County Study, the authors concluded that it is difficult to demonstrate that the costs for the establishment of a separate entity would be covered by savings from changes to interconnection or reliability.[17]

In 2016, NERC indicated that its proposed total United States net funding requirement for the Electric Reliability Organization ("ERO") is equivalent to $0.0000389 per kWh, based on the aggregate net energy for load of the United States in 2015.[18] Therefore, using the total energy production in Hawaii for 2015, we can derive an annual budgetary requirement of $393,649.[19] Assuming an inflation rate of 2% per year and assuming the load forecast for 2018 from the Power Supply Improvement Plans ("PSIP") filings, an estimate of the 2018 budgetary requirement is $482,566. Start-up costs for the entity can be estimated based on historical start-up costs for reliability organizations, using data gathered by FERC on estimates of start-up costs for RTOs. Data on start-up costs for ERCOT indicates that it required ~$4.5 million to set up operations of its Reliability Entity.[20] A review of the investment costs for PJM Interconnection, Midwest Independent Transmission System Operator, and Southwest Power Pool revealed a range of $1.5 million to $10 million as the minimum necessary startup costs required for the functions of a

[15] Under the HRS 269-149, the Commission requires that the HERA entity, "*report to the commission each year on the date of agreement under section 269-147 following the original contracting between the Hawaii electricity reliability administrator and the commission on the status of its operations, financial position, and a projected operational budget for the fiscal year following the date of the report.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-149 (2017*), 2017).

[16] Under the HRS 269-146, the Commission may require by rule, or order, that "*all utilities, persons, businesses, or entities connecting to the Hawaii electric system, or any other user, owner, or operator of any electric element that is a part of an interconnection on the Hawaii electric system shall pay a surcharge that shall be collected by Hawaii's electric utilities.*" (Source: Hawaii Revised Statutes, *HI Rev Stat § 269-146 (2017*), 2017).

[17] Ibid.

[18] FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

[19] Using total electricity production in Hawaii in 2015 of 10,119 GWh multiplied by the average NERC cost per kWh for 2015. (Source: Hawaii Department of Business, Economic Development and Tourism, *The State of Hawaii Data Book: A Statistical Abstract.* 2016.)

[20] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004. P.12.

reliability entity.[21] Using the Texas estimate provided and adjusting for Hawaii size on a $/kWh basis as described above, minimum startup costs can be estimated at $164,293.

4.3 ISO

An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[22] Under this model, the utilities would still own and rate base their transmission assets, but they would pass the day-to-day operations of the transmission system to the ISO. As discussed in Task 2.1.1, the PUC's oversight on resource planning, power purchase agreements, utility transactions, significant capital expenditure, service quality, and rates would remain the same under the ISO model. However, the ISO would take over responsibilities for reliability and long-term resource planning under this model, with overall oversight by the Commission. The utility's previous role in coordination, scheduling, and dispatch will be transferred to the ISO in this model.

4.3.1 Advantages

The main benefits of an ISO regulatory model are typically bifurcated into quantifiable benefits, i.e., ***efficiency gains of competition*** in the power supply market and ***elimination of subsidies***; and additional benefits, such as ***improved reliability, better coordination, and reduced transaction costs***.

Efficiency gains have been demonstrated in relevant empirical studies that have examined costs to consumers in the years following deregulation and creation of a wholesale power market. In one highly-cited empirical analysis of the outcomes of the PJM market, market participants realized increased gains of over $160 million over the first year.[23] A similar study of the initial benefits of the New York ISO market estimated net annual benefits equivalent to 5% of system-wide production, which is determined to have a value of over $150 million.[24]

The ISO is also responsible for ensuring short-term reliability. Analysis of deregulation in the UK in the 1990s illustrated that incentives created by competitive wholesale electricity networks lead to lower generator operating costs and improved availability.[25] The presence of an independent

---

[21] Ibid. p.8-13.

[22] EIA. *Today in Energy*. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: March 22, 2018.

[23] Mansur, E. & White, M. *Market Organization and Efficiency in Electricity Markets.* January 2012.

[24] Tierney & Kahn. *A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years*. March 2007. P.39.

[25] Newbery & Pollitt. *The Restructuring and Privatisation of Britain's CEGB – Was It Worth It?* The Journal of Industrial Economics. March 2003.

entity to oversee reliability is particularly important in Hawaii given the state's ambitious renewable energy targets.

Finally, an ISO model reduces conflicts of interest. Transferring the operations of the transmission system to an ISO would lower the conflicts of interest that Hawaii's utilities face under the status quo model. Currently, the utilities own transmission assets but are also responsible over the maintenance of reliability and resource planning. In the said system, the utilities can include transmission assets in their rate base and earn a regulated rate of return on them because they are incentivized to implement solutions that require larger capex spending or favor utility-owned generation assets, to ensure reliability and resource adequacy. With the separation of planning and ownership, the utilities become passive transmission owners and must follow the resource plans endorsed by the ISO and approved by the PUC. The ISO's independence can address the capex bias that investor-owned utilities ("IOUs") have in the current regulatory model.

4.3.2 Drawbacks

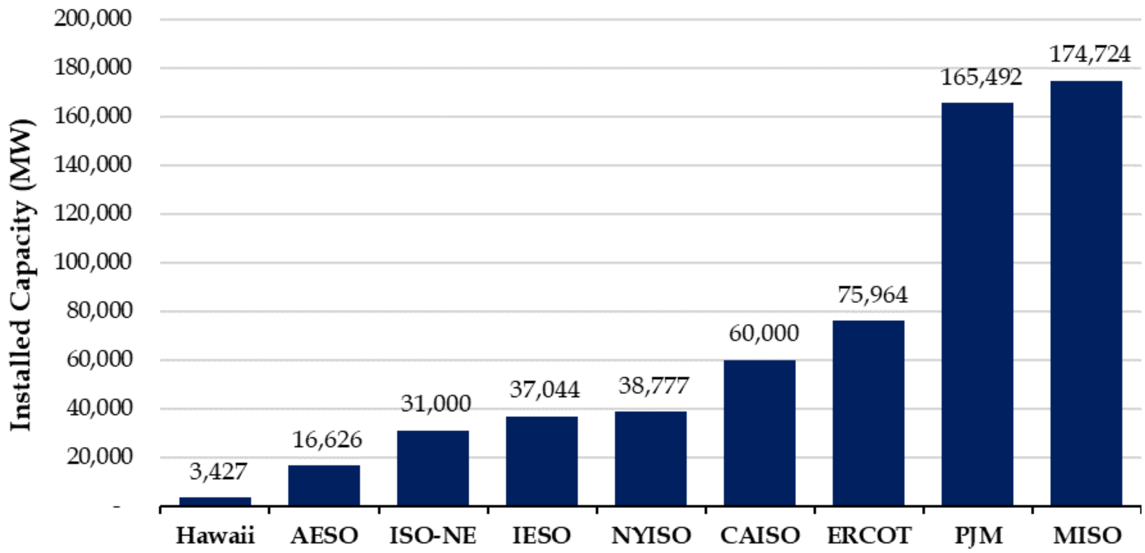
Admittedly, the ISO model is a ***technically complicated industry structure and requires highly-specialized staff*** to ensure round-the-clock coordination. The costs—in terms of time, effort, and expense—to create, staff, and transition reliably to a new market structure are very significant. All of these additional costs will be borne by ratepayers. In Hawaii, these costs may double as the lack of interconnection among the islands will necessitate multiple markets running independently, all to be coordinated by a single entity.[26] An estimate of the costs of the creation of an ISO (performed by FERC staff) suggested that annual operating costs would impact the average customer by 0.02¢/kWh, with an initial investment of between $50 million and $70 million for hardware and fully operational software (that will calculate available transmission capacity and schedule transmission and dispatch through a centralized control center).[27] The smaller size of Hawaii's electricity system (compared with other jurisdictions with ISOs and RTOs in North America) likely requires higher fixed costs for the creation of an ISO on a per capita or a per kWh basis (Figure 11).

---

[26] This is currently the case in Mexico, where the state of Baja California is islanded from the rest of the Mexican grid, and as a result, three markets operate in parallel, i.e., the Baja California Interconnected System ("BCA"), the National Interconnected System (Sistema Interconectado Nacional, or "SIN") and the Baja California Sur Electric System ("BCS"). These three markets are monitored by the National Center for Energy Control (Centro Nacional de Control de Energía, or "CENACE"), all referred to as the Mexican Wholesale Electricity Market ("MEM"), which is established as a cost-based short-term energy market with a day-ahead market and a real-time market. (Sources: SENER; IEA, *Mexico Energy Outlook.* World Energy Outlook 2016.)

[27] FERC Staff. *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization.* Docket No. PL04-16-000. October 2004.

Figure 11. Installed generation capacity in North American jurisdictions



Source: FERC, *Electric Power Markets: National Overview*; IESO, *18-Month Outlook, June 2018*; AESO, *2017 Annual Market Statistics*.

Aside from the smaller size of Hawaii's electricity system in terms of customers served or installed capacity, ***the transmission networks are also significantly smaller***. As described previously on Task 1.1.2, the State of Hawaii has less than 1,900 miles of transmission lines—817 miles in Honolulu County, 622 miles in Hawaii County, 258 miles in Maui County, and 171 miles in Kauai County.[28] Most of the transmission lines also have lower voltage—13.5 kV to 69 kV; only Honolulu County has the higher voltage lines operating at 138 kV. Higher voltage distribution lines operate at 4 kV and 12 kV.[29] Therefore, the distinction between transmission and distribution components of the power delivery system in Hawaii is not as large or as distinct as in the mainland.

Furthermore, as large, aging fossil fuel-fired power plants retire, they are being/will be replaced primarily by smaller renewables-based plants (alongside more efficient diesel units). When combined with increasing levels of DERs, the distinction between transmission and distribution is further blurred. Therefore, the roles of an ISO and a DSO are likely to have more overlap than differences in Hawaii.

The ISO model also requires a ***high level of stakeholder engagement***, which may also increase costs. As noted in Task 2.1.1, an ISO structure aims to assure reliability, which requires collaboration on the part of ISO, utilities (as the transmission owner), generators, and electricity

[28] Task 1.1.2 memo.

[29] HECO. *Power Facts – Power Delivery*. Web. <https://www.hawaiianelectric.com/about-us/power-facts/power-delivery>

utilities. As an example, at the onset of the market in Ontario, the development of the day-ahead market required a three-year transition period and a 12-month testing stage.[30]

ISO models and wholesale markets require ***careful market design*** because a poorly designed market may lead to unintended outcomes such as price spikes and damaged investor confidence. This implementation risk is not insignificant and has been demonstrated to result in inadvertent outcomes, particularly in the event of incomplete reforms.[31]

4.4 Distribution-focused regulatory model

In this model, the regulatory focus is on the optimization of the value of distribution-connected resources or DERs in the electricity value chain. The Project Team has identified a number of potential manifestations of the distribution-focused regulatory model; however, these differences, while outlined briefly here, are not important in our assessment of the regulatory model's strengths and weaknesses. As discussed in detail in Task 2.1.1, the distribution system is still owned and operated by the incumbent utilities under the distribution-focused regulatory model. This model is similar to New York's Reforming the Energy Vision ("REV"), where the distribution utility becomes the **Distributed System Platform Provider ("DSPP")**. The DSPP's new role, as envisioned by the New York regulator, is focused on "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs." As indicated in Task 2.1.1, there is currently no jurisdiction that has a full-blown distribution-focused regulatory model.

4.4.1 Advantages

This regulatory model has the ***potential to lower costs*** on the side of consumers as they will tend to shift consumption away from the grid during peak hours by optimizing DER solutions such as storage as well as benefiting from efficiency gains from competition in the DER solution markets. Moreover, ***market efficiencies from increased competition*** would likely result in lower costs. As in any other market, competition motivates players toward technological improvement and product diversification (such as cheaper backup power options) that meet the various needs of consumers.

Furthermore, providing a platform would facilitate greater penetration of renewables and DERs. ***DERs in certain jurisdictions have been observed to reduce distribution grid costs,*** eventually lowering costs on the side of consumers.[32] Benefits from improved coordination may include a

---

[30] Dewees, D. *Electricity Restructuring and Regulation in the Provinces: Ontario and Beyond.* September 2005.

[31] Joskow, P. *Lessons Learned from Electricity Market Liberalization.* The Energy Journal. 2008.

[32] In 2014, Consolidated Edison, a distribution utility in New York, projected a shortfall of 69 MW in its feeders for substations in the boroughs of Brooklyn and Queens. As an alternative to a $1.2 billion spending in substations and feeders, the utility proposed and implemented a $200 million DER program, which involved 17 MW of infrastructure investment and 52 MW of demand-side solutions. (Source: New York PSC, *Order Establishing Brooklyn/Queens Demand Management Program.* December 2014. Case 14-E-0302)

reduction in line losses, which can potentially link to a reduction in surplus procurement of generation.

It also provides wider grid access for behind-the-meter generation resources or distributed generation ("DG"). Currently, DG resources in Hawaii are predominantly rooftop solar photovoltaic ("PV") panels. The future sees increasing use of battery-backed rooftop solar energy systems as prices of batteries continue to fall. In the status quo model, the distribution system is operated by vertically-integrated utilities that own both generation and distribution-level infrastructure. They do not have the incentives to support the growth of DG because it lowers sales from utility-owned generation and could reduce the need for distribution-level infrastructure. ***A DSPP would offer more avenues for DG resources to monetize the value they provide to customers and the grid.*** DG owners can sell electricity to the grid or directly to other customers. They may also be compensated for lowering local peak loads, therefore, helping to avoid or defer costly infrastructure upgrades. In New York, Con Edison deferred a $1.2 billion distribution substation upgrade by contracting 52 MW of demand reductions and 17 MW of DERs (including DG).[33]

4.4.2 Drawbacks

Notably, this model leads to ***stranded cost risks inherent in a high DER penetration scenario.*** High DER penetration in the grid may result in decreased network load over time as customers increasingly switch their consumption during peak hours and/or become prosumers[34] in the market. This will likely increase the risk of stranded utility assets—the costs of which will be borne by remaining utility consumers, most of whom may be lower-income customers who are unable to take advantage of the benefits of owning DER technologies.

As described in Task 2.1.1, the distribution regulatory model will require substantial enhanced functional capabilities from the distribution utilities while the complex grid infrastructure required to facilitate it may require ***high-cost investments***.[35] This will also require ***extensive levels of consumer education*** to ensure success. DeMartini and Kristov of the California Institute of Technology and California ISO, respectively, note that the success of this regulatory model requires "*advanced grid platform technologies and operating procedures for the distribution utility to call upon the DERs when needed in real time and track performance*" as well as the development of

[33] Ibid.

[34] Prosumers are both producers and consumers of energy. They have on-site distributed generation behind the meter, allowing them to sell surplus power back to the grid.

[35] Distribution networks typically have very little real-time monitoring and control built into their networks, as these generally have been limited to higher voltage levels and typically used for management of faults, thus extensive transmission upgrades may be required. (Source: Bell, K. & Gill, S. *Delivering a highly distributed electricity system: Technical, regulatory and policy challenges.* Energy Policy 113 (2018) 765-777.)

"methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally" within the distribution service area.[36]

To compound these risks, there are not many precedents, therefore, ***few best practices to learn from.*** As described in Task 2.1.1, distribution-focused models are currently at various stages of implementation in California and New York, but few medium- to long-term analyses have been carried out on the impacts of these transitions on utilities and ratepayers.

Finally, as DER penetration increases, the ***possibility for bias and barriers to DER development*** from incumbent utilities could pose risks in the areas of distribution planning, DER interconnection procedures, and real-time operations. As detailed by DeMartini and Kristov, the Commission must remain vigilant as transparency, non-discrimination, and the need to minimize the risk of stranded investment becomes increasingly important due to the diversity of new players entering the DER landscape and the rapidity of changes in technologies and customer demands.[37]

It is worth reiterating that the role of an IDSO would be substantially like that of an ISO in Hawaii. The State's utilities are vertically integrated, unlike in other jurisdictions in New York and Europe with DSPP or DSO models. In such larger and liberalized markets, distribution functions are well-separated from the bulk power system. Other system operators like an ISO or a Transmission System Operator oversee functions such as dispatch, scheduling, reliability, and coordination. In Hawaii, it may be more efficient to have one system operator at both transmission and distribution levels due to the small size of the State's bulk power system. As the proportion of intermittent utility-scale renewables and DERs in Hawaii's power supply mix increases, improved coordination between transmission and distribution will become more critical in the maintenance of reliable grid operations.

4.5 PBR

As discussed extensively in Tasks 2.1.1 and 2.1.2, PBR is a regulatory approach in rate regulation and provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency. Jurisdictions shift to PBR (from the traditional COS or rate-of-return regime) due to several reasons such as lack of incentives under the COS (e.g., features that encourage prudent and efficient capital investment) and weaker incentives for cost-efficiency. Moreover, PBR allows the utility sufficient freedom to decide how to best optimize its resources given the targets and objectives. This is particularly significant for Hawaii in the context of recent legislation and proceedings toward a form of PBR.

The advantages and drawbacks of PBR models can vary based on where a particular PBR design falls (i.e., in the range from light to comprehensive mechanisms). Implementing more comprehensive PBR regulation can yield more profound benefits but at greater risk to both

---

[36] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

[37] Ibid.

shareholders and regulators. A greater proportion of utility revenues or costs are tied to incentives, which lowers the burden to maintain frequent regulatory oversight – more comprehensive PBR models typically also have a longer regulatory period, thus reducing the frequency of rate case proceedings. Utilities are encouraged to pay more attention to their performance with respect to metrics defined by the PUC, driving greater innovation as they seek to improve performance while reducing costs.

The degree of PBR regulation will likely impact costs, feasibility, performance with respect to the six evaluation criteria, and impact on utilities. The Project Team proposes to evaluate three PBR models for future deliverables under Task 2: (i) a "Light PBR"; (ii) Conventional PBR with price or revenue cap, and (iii) Outcomes-based PBR. It is important to note that ***none of the three variants of PBR is objectively "better" than the others as there are benefits and drawbacks to each***. Characteristics of the jurisdiction and objectives of the regulator are essential factors that determine the suitability of different PBR models.

As discussed in Task 2.1.1, **Light PBR** will feature expanded Performance Incentive Mechanisms ("PIMs") with rewards and financial consequences. Hawaii moved toward the establishment of PIMs when the PUC issued *Inclinations of the Future of Hawaii's Electric Utilities: Aligning the Utility Business Model with Customer Interests and Public Policy Goals* in 2014. Currently, the HECO Companies have PIMs for reliability and customer service quality.[38,39] The Light PBR would expand the current PIMs to include other metrics such as reliability, cost control, service quality, customer engagement, competitive procurement, and RPS achievement that align with State policies and energy goals. These PIMs would also be symmetrical, where the utilities would be rewarded for exceeding the targets but also penalized if they fail to meet them. The Team's Light PBR also includes the current earning sharing mechanism ("ESM") and will have the same 3-year general rate cycle.

Conventional PBR would use a revenue cap to determine the revenue requirements of the utilities, restricting their ability to increase earnings. Revenue requirements can only grow based on a pre-determined formula. Conventional PBR can support associated policy goals such as Hawaii's EV targets (e.g., through a price cap regime) and facilitate greater penetration of DERs through revenue caps. Like the Light PBR, the Conventional PBR would also include PIMs and ESM, which has a symmetrical design and increased deadband. Conventional PBR can be designed not just to improve operating efficiency but also address the capex bias that IOUs have through a total expenditure ("totex") approach. A totex approach does not distinguish between capital and operating expenditures, breaking the incentive for an IOU to favor the former over the latter.

Outcomes-based PBR can be considered as the most comprehensive PBR regime. It seeks to incentivize the utility toward beneficial outcomes to society—outcomes that may not be profitable

---

[38] Hawaii PUC. *Docket No. 2013-0141. Order No. 34514 Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues.* April 27, 2017.

[39] As discussed in Task 2.1.1., utilities are only assessed a penalty for failing to meet reliability targets and not rewarded for exceeding them, whereas the customer service quality PIM features both rewards and penalties.

to the utility under traditional COS regulation. The Project Team identified four potential outcomes: (i) enhance customer experience, (ii) improve utility performance, (iii) achieve public policies and goals, and (iv) healthy financial performance. Moreover, in this alternative, the Project Team would incorporate stringent reporting regimes and require submission of asset management plans to complement the PIMs.

4.5.1 Advantages

PBR mechanisms have some demonstrable advantages over COS regulation. PBR mechanisms have been shown to result in ***improved incentives*** for utilities and can be designed such that they ***drive innovation*** and ***better investment decisions*** from utilities. The PBR approach may reduce administrative and regulatory costs (e.g., due to fewer regulatory proceedings) as well as lead to more stable rates for customers.[40] A well-designed multi-year PBR with well-defined mitigation measures can also reduce regulatory risk on the utility, lowering its cost of debt and, ultimately, in the side of consumers.

Moreover, utilities are ***encouraged to operate more efficiently*** so they can achieve or surpass the productivity targets. PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[41] This benefit is precisely the incentive that motivates companies in competitive markets to control costs and deliver exceptional service to their customers. The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, the regulator, the British Columbia Utilities Commission ("BCUC") noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[42] In the UK, Ofgem stated that the PBR regulatory framework has brought benefits to electricity customers over the last 20 years and has "*delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices.*"[43] In fact, "*since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization.*"[44]

---

[40] Rate stability under a PBR mechanism is a function of the rate setting formula. Utility rates, typically under an I-X approach will only increase by inflation (I) less the productivity factor (X) plus other flow-through mechanisms. This will be over multiple years, allowing for a longer-term outlook for utility rates. (Source: Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.)

[41] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[42] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, page 22.

[43] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

[44] Ibid.

Efficiency gains from PBR mechanisms can be shared with customers through ESM. ESM can also lower costs to consumers and ensures effective customer participation in a company's financial performance.[45] In Hawaii, ESM has been implemented along with the Rate Adjustment Mechanism since 2011, as part of the Revenue Decoupling Mechanism approved by the PUC.[46] Through this mechanism, if actual utility returns exceed the PUC-approved rate of return on equity ("ROE"), rates will be lowered to share the "excess" returns with customers. However, utilities cannot use ESM to increase revenues if their actual returns fall below the PUC-approved ROE.

Reliability can also be safeguarded under a PBR regime, especially for plans that have mandated performance standards, which in some jurisdictions also entail a system of penalties and rewards. The presence of incentives provides a strong motivation for utilities to improve their quality of service. Ofgem believed that the implementation of PBR *"has led to significant improvements in quality of service. Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."*[47] With performance standards in place under a PBR regime, distribution line losses may also improve. In Ontario, line losses of Hydro One decreased steadily for the six years since 2011: by 0.3% on average per year from 1,711 GWh in 2011 to less than 1,625 GWh in 2016.[48]

Moreover, the PBR model could reduce ***administrative and regulatory costs*** in the long term by reducing the number of litigated rate cases for the utility. This is particularly true for the existing Hawaii regulatory framework, where the duration of the rate case application is over 24 months.[49] Reduced regulatory costs under PBR are a result of PBR's recognition of the information asymmetry between the regulatory body and utility. Under COS, regulators spend a considerable amount of time and expense to bridge the information gap.

In contrast, PBR does not try to rectify this information gap. Instead, under the PBR regime, the Commission does not need to know the costs for each O&M item but only the range of possible costs from which the Commission can approve a PBR plan that can elicit maximum efficiency from the utility.[50] Moreover, regulators benefit from PBR to the extent that it eases them out of the demanding task of micro-managing the activities of the utility. For the utilities, reduced

---

[45] Sappington, David et al. *The State of Performance-Based Regulation in the U.S. Electric Utility Industry.* 2001. The Electricity Journal. 71-79.

[46] Hawaii PUC. *RAM Legal Notice.* March 31, 2011. <https://puc.hawaii.gov/wp-content/uploads/2013/06/20110427-RAM-legal-ad.pdf>

[47] Ibid.

[48] Ontario Energy Board. *Yearbook of Electricity Distributors (2011-2016).* Accessed at: <https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks>

[49] LEI analysis of rate cases between 2009 and 2017 for the HECO companies showed that of the seven (7) rate cases reviewed, three (3) took at least 30 months to decide, while only one (1) was settled in less than 10 months. (Source: Hawaii Public Utilities Commission).

[50] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I.* November 1995. P. 6.

regulatory micro-management allows them to respond more quickly to technological and competitive challenges. This may mean lower prices for customers.

Additional PIMs under Light PBR can also align the interests of utilities and customers. The utilities, PUC, consumer advocate, and other intervenors are already familiar with and understand how this structure works. This familiarity can lower implementation costs and make it more likely that the utilities can achieve performance targets.

Specifying outcomes regarding customer experience, utility performance, and societal policy goals, among other goals under the Outcomes-based PBR, ***encourage the utility to invest in areas that they may not otherwise***. The ***increased earning opportunities create a revenue driver*** for utilities. Outcomes-based PBR is also typically implemented without necessarily specifying the exact mechanisms that utilities must adapt to achieve the outcomes. This leaves the utilities free to innovate and find a solution that produces outcomes at the lowest possible cost.

Lastly, the Outcomes-based PBR is also the ***most beneficial in advancing specific policy and regulatory goals***. This effectiveness stems from (i) the ability to have outcomes that reflect important public policy goals, (ii) flexibility in terms of offering the utilities a fair degree of leeway in how they can achieve those goals, and (iii) accountability in the regulatory process.

4.5.2 Drawbacks

As noted in Task 2.1.1, moving from a traditional COS to PBR can be a major undertaking not only for the regulator but also for the utilities. It involves a ***significant amount of regulatory work and requires lengthy stakeholdering efforts*** to determine the appropriate PBR mechanism that may be implemented and allow more in-depth analysis of sectoral and technical issues, discussions of which are not always present or as thoroughly dissected during a COS deliberation. This regulatory effort can be driven by ***availability, accuracy, and consistency of data***. Data is often inconsistent or even unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes, and differences in accounting techniques, and mergers and amalgamations, to name a few. Ensuring data consistency and credibility requires configuring systems and processes correctly.

Sufficiency of capex funding under a PBR approach can be a concern if there are no other capital incentive mechanisms in place other than the indexing formula (inflation less productivity factor) or if the explicit capital incentive mechanism provided is very restrictive. Including a capex mechanism within the PBR formula or, at a minimum, incorporating a feature to reduce regulatory risks associated with capital outlays beyond the control of management may, in fact, provide for increased stability and ensure the longevity of a PBR mechanism.

PBR mechanisms face ***forecasting requirements and challenges***. The preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[51] Forecasting plays a central role in the building blocks approach-based PBR. Poor

[51] Items that need forecasting include load growth, energy growth, depreciation, number of customers, cost of capital, and operating, capital and tax expenditures, to name a few.

forecasting on the side of utilities can also lead to potential additional costs and/or penalties affecting their bottom line. In practice, forecasts can significantly deviate from actual figures so the PBR design must include mechanisms that will provide a degree of protection to both shareholders and ratepayers. These mechanisms may consist of re-openers, ESM, true-ups, rebasing, and flow-through.[52]

Nevertheless, Hawaii can learn from the experiences of jurisdictions that are currently under PBR (both in the US and across the world) on how to manage a transition to PBR in a timely and effective manner.

For Light PBR, identifying appropriate metrics and setting targets can be a challenging task. Some metrics are impacted by many different factors, not all of which may be under the utilities' control. Likewise, an ESM can somewhat increase the administrative burden of PBR because it requires additional effort in determining the earning sharing amount. More importantly, an ESM blunts the efficiency incentives created by the shift to PBR.

The potential drawbacks are also amplified under a more comprehensive PBR regulation. Formulating the details of PBR design is a more extensive and expensive process. The model must be based on rigorous analysis to ensure that the incentive mechanisms can achieve what they are meant to and will not lead to significant unintended consequences. The PUC and regulators both need more accurate data monitoring capability to evaluate performance levels and adjust for the impact of changes (e.g., in weather patterns or macroeconomic conditions).

Finally, a drawback of an Outcome-based PBR is the complexity of putting together a compelling business plan that will justify the utilities' revenue requirements for the 5-year regulatory period. The utilities are also required to submit several documentations such as a detailed plan (that includes their investment and asset management plans) and other documents that support their PBR implementation. Another negative consequence is the additional costs required in the hiring of consultants by both the utilities and the PUC. Generally, consultants are hired to help utilities in putting the PBR plan together and defending it. Consultants who can assist the Commission in the review of the PBR plan and determine whether the proposal is justified are also hired.

[52] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive ("IQI") to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. Moreover, it rewards utilities with lower expenditure forecasts and provides mechanism for utilities with higher expenditure forecasts to beat the targets by spending less.

5 Evaluation of regulatory models relative to state criteria

The evaluation of regulatory models relative to the State's criteria is both qualitative and high level at this stage of the project. Results are subject to refinement and change as the project proceeds and feedback from stakeholder groups and quantitative analysis become available.

The scoring mechanism is intended as a thought exercise in comparing the various regulatory structures. Each regulatory model was ranked from the most favorable to the least favorable. The scoring does not differentiate between instances in which items were close in ranking versus widely different. It should be noted that this is purely illustrative and may be adjusted in the final report as the results of subsequent stakeholder consultations and analyses become available.

The different regulatory models are evaluated with respect to their ability to address the following state goal criteria, like the criteria used in the ownership models:

i. meet state energy goals, particularly Hawaii's mandated RPS goal of 100% renewable energy by 2045;

ii. maximize consumer cost savings;

iii. enable a competitive distribution system in which a marketplace allows customers and independent agents to trade energy and other evolving services that can meet customer and grid needs;

iv. address conflicts of interests in energy resource planning, delivery, and regulation; and

v. align stakeholder interests.

Aside from the State's goals above, the Project Team is including the sixth criterion to provide a holistic understanding of the transition costs within the context of advantages and disadvantages and provide greater input into the evaluation process:

vi. length and costs of transition to other regulatory models, given current laws, regulatory structure, and organization.

5.1 Ability to meet state energy goals

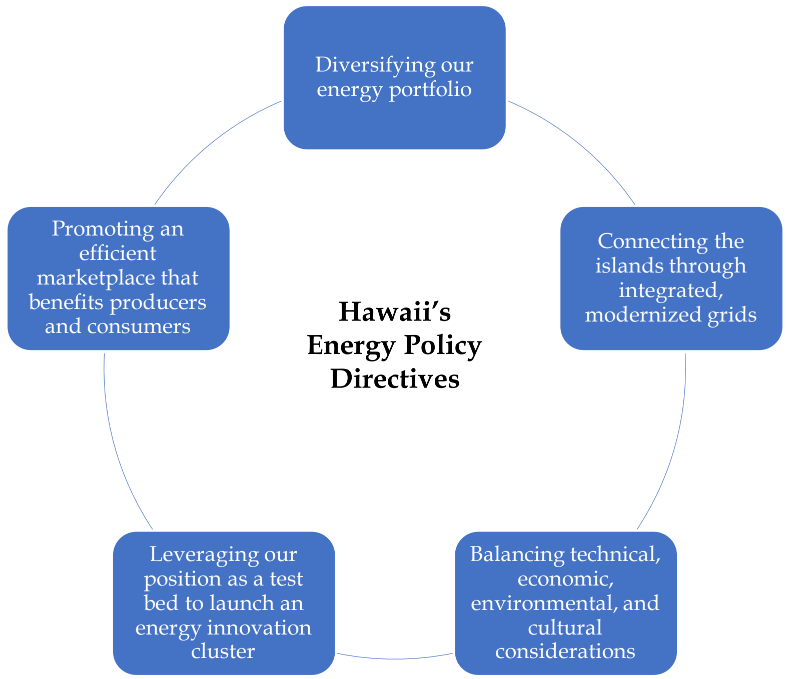
Hawaii has the most aggressive renewable energy targets in the US. It aims to source 100% of its electricity from renewable energy by 2045.[53] Also, Hawaii's energy policy focuses on its "*commitment to maximizing the deployment of cost-effective investments in clean energy production and management to promote the State's energy security*."[54] More specifically, the State aspires to achieve a diversified energy portfolio that makes the best use of land and resources; have an efficient

[53] HI Rev Stat § 269-92 (2015).

[54] HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. <http://energy.hawaii.gov/energypolicy>

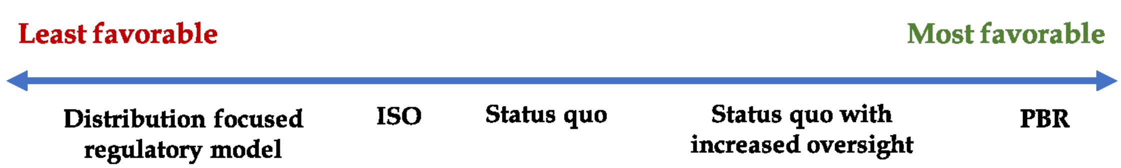
marketplace that is beneficial to all; create integrated and modernized grids, and be recognized as an energy innovation center.[55]

Figure 12. Hawaii's energy policy directives



Source: HI Rev Stat § 269-92 (2015), Hawaii State Energy Office ("HSEO").

Figure 13. Ability of each model to meet state goals



Source: LEI analysis.

For this criterion, the Project Team focused on Hawaii's target to achieve 100% of its electricity from renewable energy by 2045. The other policy directives (Figure 12) are covered by the other criteria. For example, "balancing technical, economic, environmental, and cultural considerations" is reflected in criteria (v): align stakeholder interests. Likewise, "promoting an efficient marketplace that benefits producers and consumers" is substantially similar to enabling a competitive distribution system.

[55] Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).

Hawaii's utilities have made significant progress toward the 100% renewables target under the status quo regulatory structure, where the Hawaii PUC maintains oversight of the State's utilities. In fact, all but one of the utilities are ahead of the current intermediate RPS target of 30% by 2020.[56] HECO had achieved renewables contribution of 20.8% (as of December 2017) but its subsidiaries, MECO and HELCO, have surpassed the 2020 RPS target with RPS of 34.2% and 56.6% respectively.[57] The HECO Companies have a consolidated renewables contribution of 25.8%. Likewise, KIUC has exceeded the RPS target with combined renewable energy and energy savings at 44.4% of net electricity sales.[58]

This indicates that the State's renewable energy goals are potentially attainable under the status quo. All four utilities are vertically integrated and own most of the generation within their territories, with IPPs entering into PPAs with the respective utilities. This centrally controlled structure allows the PUC to push the utilities toward the RPS targets, supported by higher penetration of DERs. The PUC and utilities have encouraged the growth of DERs in Hawaii, particularly rooftop solar [through Net Energy Metering ("NEM")] in the past, and currently with the Smart Export and CGS+ programs.[59]

Keeping the current structure but increasing oversight of the utilities through a new independent agency such as HERA can further support the achievement of the State's energy targets. One of the main challenges with integrating high levels of intermittent renewable energy on the grid is the maintenance of reliability, which is currently overseen by the utilities themselves and monitored by the PUC. Transferring the enforcement of monitoring responsibility to HERA can prevent or at least minimize the tendency of utilities – under the status quo model – to be more conservative than necessary in integrating renewable resources (to maintain reliability Aside from the need to implement reliability standards across the electric value chain, HERA's mandate also includes providing fair grid access to generators.[60] This can open more opportunities for renewable generators and DER providers. Therefore, the Project Team scored increased oversight by an independent agency more favorably than the status quo model.

The PBR model, if well-designed, is considered to be the most favorable in achieving the State's RPS targets because the PUC can set incentives and penalties explicitly based on progress towards pre-established goals such as "rapid integration" of renewables (including third-party home solar

[56] HB 623 HD2 SD2 CD1, *Relating to Renewable Standards.* House of Representatives, Twenty-Eight Legislature, 2015. State of Hawaii. Web. Accessed May 10, 2017.

[57] Hawaiian Electric Company. *2017 Renewable Portfolio Standard Status Report.* February 8, 2018.

[58] Kauai Island Utility Cooperative. *2017 Annual Renewable Portfolio Standards Status Report.* March 29, 2018.

[59] The Smart Export and Customer Grid Supply + ("CGS+") programs allow customer sited solar generation to supply power to the HECO companies at fixed rates. The Smart Export program allows up to 3,500 to 4,500 customers to export energy through their solar-battery system to the grid during evening, overnight, and early morning (i.e., 4:00 PM to 9:00 AM) following charging during the day. The CGS+ program allows approximately 5,000 to 6,000 customers with solar PV-only systems to export energy to the electric grid during the day (Source: Hawaii Public Utilities Commission).

[60] Hawaii Senate Bill 2787 (2012).

and storage systems), affordable rates, electric reliability, and customer choice and satisfaction (specific PBR metrics can be set for any of these criteria). The PBR model scores very favorably because it enables a "carrot and stick" approach that can be designed to both encourage utilities to achieve targeted performance and penalize them for underperformance. It also allows the utility freedom in optimizing its resources given targets and objectives.

The ISO and distribution-focused regulatory models both score less favorably than the status quo because they fail to address incentives at opposite ends of the generation spectrum. The ISO model can facilitate the development of significant renewable projects by increasing competition at utility-scale. As an independent body, system planning conducted by an ISO would also level the playing field between generators and allow renewables to compete based on cost and value to the grid. On the other hand, an ISO model without new initiatives at a distribution level will not substantially expand opportunities for DERs to participate. Conversely, a distribution-focused model can support the growth of DERs by unlocking additional value for them by incorporating them into distribution-level planning, allowing them to provide grid services and facilitating direct transactions with other customers. However, such a model does not address generation (at utility-scale), which accounts for most of the generation.

5.2 Maximize consumer cost savings[61]

Hawaii's customers already pay the highest rates for electricity in the US. The average electricity price across all sectors in 2016 was 132% higher than the national average and 33% higher than the next most expensive state, Alaska.[62] Ratepayers bear several categories of costs that are impacted by regulatory structures, including (but not limited to): (i) power supply including fuel costs; (ii) other utility operating costs; (iii) costs of regulatory proceedings; (iv) fees to fund regulatory bodies such as PUC (and HERA, if implemented); and (v) return on capital investments.

Regulatory models can lower the costs faced by customers if they can support the development of lower cost resources for generation, reduce reliance on expensive imported oil, incentivize the utility to be more efficient and cost-effective in its operations, lower the regulatory burden (including the length of typical regulatory proceedings), or reduce the bias for utilities to favor capital expenditure ("capex") for higher returns.

The PBR model is regarded as the most favorable in terms of reducing costs to consumers in the long run because it can incorporate incentives to control costs under both price- and revenue-cap approaches, while still maintaining service quality as well as other parameters set by the PUC (Figure 14). It can also set incentives that de-emphasize the importance of returns on capital investments for utilities' profitability. Indeed, in its order instituting the PBR proceeding, the PUC outlines its interest "in ratemaking elements and mechanisms that result in:"[63]

---

[61] The consumer cost savings considered in this section excludes consideration of implementation costs.

[62] EIA. *Electric Power Annual 2016.* Revised May 2018.

[63] Hawaii PUC. *Docket No. 2018-0088 Instituting a Proceeding to Investigate Performance-Based Regulation.* Order issued and effective April 18, 2018. page 52.

- greater cost control and reduced rate volatility; and
- efficient investment and allocation of resources regardless of classification as capital or operating expense.

It is important to note that establishing PBR will initially require time and impose a sizable regulatory burden on both utilities and the PUC, the costs of which will be passed on to ratepayers. However, once implemented, this model can achieve reductions in multiple categories of costs, creating higher savings for consumers in the long run.

An ISO model can also lower costs of the power supply by increasing competition in generation. Likewise, independent transmission planning and operations can lower system-wide costs. It also addresses utility bias towards capex, at least at the transmission-level, because utilities will make investments based on the ISO's planning. This is a more favorable environment for lowering costs to consumers than the status quo, where the utilities have no incentives to minimize costs due to the cost of service ratemaking regime. Costs to consumers are controlled in regulatory proceedings, such as rate cases, by the PUC and the Division of Consumer Advocacy ("DCA"); however, COS regulation has been observed to provide an incentive for utilities to overstate capex (to increase returns on investments), subsequently and possibly resulting in higher costs.

The regulatory burden only increases for both utilities and HERA in a HERA model. To comply with regular reporting requirements, utilities will have to monitor and track various metrics on reliability and grid access. Furthermore, HERA will have to be staffed with trained personnel to enforce standards and ensure utility compliance. There will also be an additional reliability surcharge on ratepayers to fund HERA.

Figure 14. Ability of each model to lower costs to consumers

Source: LEI analysis.

A distribution-focused regulatory model is the least likely model (at present) that can reduce costs (in the short term) to consumers. Such a model requires extensive investment in grid-modernization technologies. Some of the technologies needed for a fully-fledged version of this model have not been operationalized outside of pilot tests. The enabling technologies, both hardware, and software, may improve capability and become cheaper over time. The full costs of transition to a distribution-focused model are largely unknown, but they are likely to be high based on prevailing market conditions. These costs will eventually be passed on to ratepayers.

5.3 Enable a competitive distribution system

A competitive distribution system is one "in which independent agents can trade and combine evolving services to meet customer and grid needs."[64] This goal requires the evolution of grid operations and services away from the traditional utility business model where the utility has a monopoly over the sale of electricity and other limited services to the customer. The traditional regulatory models are not as favorable for a competitive distribution system as more innovative ones.

The status quo model offers programs like Smart Export and CGS+ to expand rooftop solar and battery storage. However, this approach limits the competitiveness at the distribution level because the utility remains the sole buyer of electricity from distributed generation, excluding any separate bilateral contracts between independent parties. Technology providers can offer their services to utilities as well as customers. Utilities increasingly partner with third-party companies especially for their need for software and other services that support grid management. For example, HECO is using Opus One's GridOS Dynamic Hosting Capacity software to understand how much DERs can be integrated into a distribution feeder to better optimize grid assets in real-time.[65] Customers can also purchase products and services (like the Nest thermostat and similar home energy management systems) from third-parties. However, such opportunities for customers and other market participants are defined by the utility through scope, requirements, and rates.

Adding increased oversight is slightly more favorable than the status quo model. Independent planning by an entity such as HERA can address the tendency of utilities to limit the participation of DERs and service providers, for example, by using excessively stringent criteria. HERA's responsibility to oversee grid access can ensure that grid-services provided by DERs[66] are integrated into planning without impacting reliability.

---

[64] Hawaii Contract No. 65595. Scope of Services.

[65] "Hawaiian Electric and Opus One Collaborate on Grid Modernization." *Opus One Solutions*, 18 April 2018. Web. Accessed on May 17, 2018. <www.opusonesolutions.com/news/hawaiian-electric-and-opus-one-collaborate-on-grid-modernization>

[66] According to a survey of literature on benefit-cost analyses of behind-the-meter resources conducted by eLab, DERs can provide grid support services (in addition to energy and capacity) such as reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, and synchronized and supplemental operating reserves.

The ISO model is regarded as more favorable than the status quo models because it enables greater participation of DERs at the wholesale level. For example, FERC Orders 745 and 841 have opened additional opportunities for demand response and energy storage to participate in wholesale markets and be compensated appropriately in other North American jurisdictions. Under the ISO model in other jurisdictions, DERs can compete with generation and even transmission upgrades in meeting system needs.[67] Utilities in markets with an ISO have begun to deploy DERs as Non-Transmission Alternatives ("NTA") to defer or even replace the need for transmission upgrades. The independence of ISOs is important to ensure that the competition is not biased in favor of utility-owned generation or new transmission projects with high capex.

Likewise, the PBR model can be more favorable than status quo models because of the incentives and penalties that can be designed based on the criterion: increasing competition at the distribution level. New York is pursuing a version of this by soliciting innovative solutions by various features including Advanced Metering Infrastructure ("AMI") network access, customer response to smart home and time-of-use rates, Energy Marketplace 2.0, increasing hosting capacity, reducing peak, and Non-Wires Alternative ("NWA") projects.[68] Incorporating Earnings Adjustment Mechanisms ("EAM") in the PBR mechanism can be favorable for a competitive

Utility financial incentives in NY's REV

Currently, the utilities in New York can receive incremental performance incentives for achieving REV objectives through Earnings Adjustment Mechanisms ("EAM"). There are currently five EAM opportunity areas:

- **System efficiency and peak reduction** – improve overall system efficiency to reduce capital investment, including peak reduction and load factor improvement;
- **Energy efficiency** – support greater overall energy efficiency savings and the transition to market-based approaches;
- **Interconnection** – improve processes for the interconnection of DG projects, as measured by a DG developer;
- **Customer engagement** – increase customer uptake in specific innovative programs; and
- **Greenhouse gas reduction** – support the electrification of transportation, building heating and cooling, reduce the cost of achieving New York's goal of getting 50% of electricity from renewable sources by 2030.

Source: NY REVConnect. *Track Two: REV Financial Mechanisms.*

---

[67] Only California's market, operated by CAISO, allows aggregate DERs to participate in the wholesale market, in both the energy and ancillary service markets. This take the form of a DER provider ("DERP"), a market participant allowed to aggregate DERs to meet the 0.5 MW requirement to participate. Examples of DERs that can participate under this market arrangement include generation such as rooftop solar PV, energy storage, plug-in electric vehicles ("EV"), and demand response (Source: CAISO. *Distributed energy resource provider.* <http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx>)

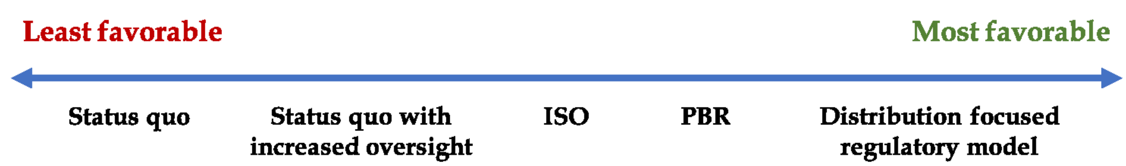
[68] "Innovation Opportunities." *REV Connect*, Accessed on May 17, 2018. <nyrevconnect.com/innovation-opportunities/>.

distribution system because utilities have incentives to increase participation of third-party service providers. The textbox provides an example of the EAMs in New York.

The EAMs and solicitation of innovation opportunities, as designed in New York's REV, may help align utility incentives and increase competition at the distribution level. However, it retains a centralized approach to procurement, which could undermine initiative and creativity. New York's efforts with NWA programs and EAMs are considered transitionary steps toward a fully-fledged distribution-focused regulatory model, conceptualized as a DSPP.

A DSPP or IDSO model can be the most effective model in enabling a competitive distribution system because customers, DER providers, and service providers can transact with each other in the future under this model without the utility serving as an intermediary or defining solicitation criteria (Figure 16). Compared with other regulatory models, a distribution-focused model allows buyers and sellers of energy and other services to interact directly with each other. Such increased transparency can encourage more participation in distribution markets. In New York, utilities can earn platform service revenues, which are tied to the selling of products and services that facilitate distribution-level markets, shared revenue opportunities, and other options for customers (such as the ability to pay a fee for value-added services such as advanced data analytics).[69] If a similar mechanism is instituted in Hawaii, utilities would have a stronger incentive in facilitating the growth of distribution-level markets than under a PBR model.

Figure 15. Ability of each model to enable a competitive distribution system



5.4 Address conflicts of interest

Conflicts of interest can take place between and among utility shareholders, ratepayers, regulators, and market participants like IPPs and DER providers in matters of energy resource planning, delivery, and regulation. Addressing conflicts of interest requires as much separation of planning and operational control from investment and ownership as possible. The performance of various regulatory models in addressing conflicts of interest has been discussed in the previous three criteria and will be summarized again in this section.

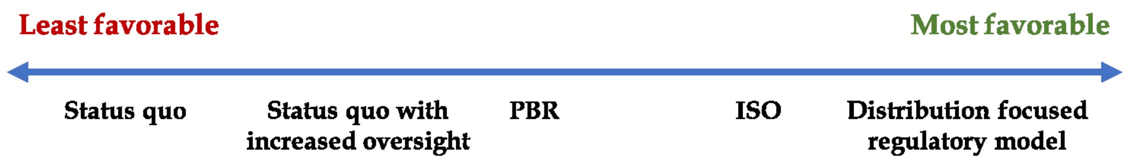
The status quo model is the least favorable because the PUC is the sole entity responsible for addressing or managing conflicts of interest (Figure 16). The utility maintains full control of energy planning and delivery with PUC oversight being the only check. This means that there is information asymmetry between the utility and the regulator, i.e., only the regulator has access to as much information on the utility's actions as the utility provides. Increasing oversight with HERA can help spread the regulatory burden between agencies. The independent planning can

---

[69] Ibid.

also help address utilities' potential conflict of interest against IPPs and DERs, for example, by separating some of system planning functions. A PBR model can use incentives and penalties to align the utilities' business models—a step, which helps in guarding against or managing conflicts of interest—but it will not result in full separation of planning and operational control from investment and ownership. Such a separation is achieved by a distribution-focused regulatory model at the distribution level and an ISO model for the transmission system and utility-scale generation. Combining both an ISO and a DSPP/IDSO model would be most effective in addressing conflicts of interest.

Figure 16. Ability of each model to address conflicts of interest



5.5 Align stakeholder interests

This criterion—alignment of stakeholder interests—is similar to the previous one but with more focus on whether stakeholder interests are aligned rather than whether conflicts can be resolved. The status quo model is, again, the least favorable because the utility's interests are in increasing profits (ultimately through rates) and making stakeholders happy whereas ratepayers want to keep their electricity rates low (Figure 17). This conflict plays out through other channels as well. Ratepayer interests favor greater participation of DERs and IPPs to keep their costs low. This would harm utilities' profitability unless they could increase capex in grid modernization infrastructure to accommodate more DERs—a step, which negates the cost-reduction value of DERs. Increasing oversight of the status quo along with the accompanying independent planning could better align interests between ratepayers and utilities.

A distribution-focused regulatory model is more favorable than the other models in this criterion because utilities are focused on providing the necessary level of distribution infrastructure. An independent DSO is perceived as fairer than the status quo utility because it has no incentive to increase its profitability beyond what is necessary to keep it financially healthy. Likewise, the ISO maintains similar independence in transmission planning and operations—a feature, which would help increase competition in utility-scale generation. Furthermore, ISO or DSO would both align the interests of ratepayers, utilities, and market participants.

However, a PBR model, if designed correctly, is the most favorable of all the regulatory models in this parameter because there are multiple avenues, where stakeholder interests may be aligned (e.g., through incentives). Incentives based on shared savings can be designed to both decrease capex spending and increase operational efficiency, resulting in lower rates while aligning interests with the utility. Likewise, other incentives based on RPS achievement, DER interconnection, and similar programs benefit both ratepayers and utilities. The incentives and penalties in a PBR model are determined in regulatory proceedings in which stakeholders can intervene, allowing both ratepayers and utilities to provide their inputs.

Figure 17. Ability of each model to align stakeholder interests

5.6 Process and costs of transition

The additional criterion proposed by the Project Team is the transition cost. Section 5.2 compares the regulatory models based on cost savings for consumers *after* the transition has been completed. It is essential to look at the steps needed to move to a new regulatory model to understand the level of opposition and delays that the process may encounter, all of which can substantially increase the transition costs. Task 2.3.1 will discuss this in detail. The more stakeholders involved in the transition process and the more approvals required likely indicates a greater probability of delays. Likewise, it is important to consider if a new regulatory model will require divestment of assets by the utility. This can increase the opposition of the utility and increase the likelihood of an expensive litigation process as well as an increase in the timeframe required to sell assets.

Maintaining the status quo would require no changes; adding increased oversight will likely be the next best option in terms of transition costs and timeframe (Figure 19). The law that requires the establishment of HERA already exists through state legislation (Act 166) in 2012. There will still be costs in setting up HERA as a functioning organization. The PUC is authorized to contract with a person, business, or organization (except a public utility) for the performance of HERA's functions.[70] Therefore, it must set the requirements for interested entities and run a competitive solicitation. Furthermore, there may be additional costs in hiring the personnel with the necessary expertise and/or providing additional training to the new staff. While this process must be conducted thoroughly, there are no glaring pitfalls that could result in lengthy stakeholder outreach or expensive litigation.

Compared to the move to a HERA model, the move to a PBR model could be a lengthy and expensive process, especially during the first regulatory period, despite the recently enacted legislative mandate. PBR has several "flavors"—ranging from "soft" to "hard" mechanisms—and involves price- vs. revenue-cap approaches (as discussed in Task 2.1.1.). Moreover, several criteria can be linked to performance targets. The exact combination of various components of PBR can result in substantially different incentive/risk profiles and revenue opportunities for the utility. For first-generation PBR, there will also be costs related to the hiring of external consultants and experts (who can provide guidance on designing PBR proposals) by both the PUC and utilities. The length of the process for deliberation (e.g., between proposed PBR models), incorporation of stakeholder feedback, and finalization of the ultimate design could take between several months to more than a year.

---

[70] HRS 269-147.

An ISO model is even less favorable in terms of transition costs because it requires the actual purchase of physical equipment in addition to the establishment of a new organization. First, there may be a need for legislation (toward the creation of an ISO) after due process and deliberation. This can be a lengthy process itself due to the need for extensive stakeholder engagement. There must also be a clear demarcation of authority between/among the new ISO, utilities, and the PUC.

In addition, the establishment of the organization requires defining of clear governance structures, the hiring of appropriately qualified staff (both from current utilities and externally), and the establishment of the office. It will require separate premises and office infrastructures such as computers, IT infrastructure, and furniture (some of which might come from the utility and some purchased). The specific software and equipment used by the current utilities for system planning, dispatch, and day-to-day operations can be obtained from the utilities themselves.

The distribution-focused regulatory model is regarded as the least favorable due to the extent it varies from the current utility business model, the infrastructure needed to enable it, and the degree of unknown costs. As with the ISO model, legislation that supports the move to a distribution-focused model should first be passed, but such a law requires an extensive stakeholder engagement process. However, while there are several examples of well-functioning ISO markets, the same cannot be said of a DSO or DSPP market.

Figure 18. Relative performance of each model with respect to transition costs

There are several jurisdictions moving towards different versions of such a model, but they are still in transition. A move towards this model will require extensive levels of new customer- and grid-facing technologies, some of which have not yet been deployed commercially outside of pilot projects. The full cost of such enabling infrastructure is currently unknown but likely to be high. In New York, preliminary investments in enabling technologies and pilot programs for DSPP development range between $11 million and $190 million between 2017 and 2021, depending on the technology, utility service area, and current status of utility infrastructure.[71] Moreover, this model may require the utilities to divest their generation or at least separate them into an unregulated subsidiary, depending upon the exact design and implementation. This can make the process much more complex and even more expensive because Hawaii's utilities are still vertically-integrated unlike in other jurisdictions that are moving toward a distribution-focused regulatory model.

[71] From Task 1.1.4 memo.

6 Potential hybrid regulatory models

The discussions in the previous chapters demonstrate that each regulatory model carries its own set of advantages and disadvantages and performs differently in the six evaluation criteria. Excluding the sixth criterion, i.e., the process and costs of transition, the Project Team's analysis considers the PBR model to be most favorable in meeting three of the five criteria. The distribution-focused regulatory model was considered most favorable in its ability to achieve a competitive distribution system, and both distribution-focused regulatory and ISO models were regarded as most favorable in addressing conflicts of interest (Figure 19).

Figure 19. Most favorable model for each evaluation criterion

Criteria	Most favorable model
Meet state energy goals	PBR
Lower costs to consumers	PBR
Enable a competitive distribution system	Distribution focused regulatory model
Address conflicts of interest	ISO/Distribution focused regulatory model
Align stakeholder interests	PBR
Minimize process and transition costs	Status quo

The preliminary analysis shows that the PBR model is the most effective model overall. However, the regulatory models described here are not necessarily mutually exclusive. This is especially true of the PBR model, which can be designed to be effective alongside an ISO, a DSPP/IDSO, or under additional HERA oversight. Based on Figure 19, combining PBR with both an ISO and a DSPP/IDSO could even be more effective in meeting the State's goals (except transition costs).

6.1 Conventional PBR + Light HERA

A combination of the Conventional PBR and a Light HERA could be able to help achieve most of the state goals discussed in the previous section. More specifically, this hybrid model could lower costs to consumers in the long run due to the indexing formula of the Conventional PBR. Since revenues are fixed, utilities are incentivized to be more efficient in their expenditures while still achieving their mandated targets. Combining this with the Light HERA will also lower costs as the HERA entity will provide a fair interconnection process, where third-party power providers can compete with the utility in offering the most cost-effective solutions.

This could also enable a competitive distribution system as HERA manages the DER interconnection process in a fair and transparent manner. Adding Light HERA to the regulatory regime would simplify the monitoring of the DER interconnection process (including associated reliability and hosting capacity analyses) by moving these tasks to an independent body. DER interconnection requests would be prioritized based on how beneficial they are to the overall grid not just to the utilities' bottom line. Moreover, conventional PBR with revenue caps can encourage utilities to support the growth of DERs. However, the incentives to do so would predominantly apply in cases where utilities can lower their costs by deploying or directly owning DERs.

Conflicts of interest will also be minimized or reduced because HERA functions as an independent appeals body that can help settle differences. The combination of the Conventional PBR and Light HERA aligns stakeholder interests because PIMs can be designed to address stakeholders' concerns. Process and transition costs can be lower in the long run. For instance, there will be fewer rate filings because of the fixed PBR regulatory term, and litigation process that allows HERA to act as the ombudsman tasked to assist in settling differences between the utility and customers (e.g., on issues related to interconnection and hosting capacity).

The Light HERA entity also frees up the utilities' resources, so they can focus primarily on improving efficiencies and lowering costs. This has the potential to deliver the more significant benefits that are usually found in the Conventional PBR model. Moreover, both components of this combined regulatory model are already being implemented in other jurisdictions. Therefore, lessons learned from their experience can be considered in designing these regulatory models. The different mechanisms with which it has been implemented are detailed in Task 2.1.1. Likewise, there is already legislation for a HERA in Hawaii; no further legislation would be required for a Light HERA entity.

6.2 Outcomes-based PBR + DSPP + Independent Grid Operator

Another combination that could achieve most, if not all, of the state goals, is the combination of an Outcomes-based PBR, DSPP, and ISO/DSO.

As mentioned earlier, given the smaller size of Hawaii's transmission systems (compared to jurisdictions elsewhere), the Project Team believes that combining the functions of the ISO and independent DSO is more effective and efficient in the Hawaii context. For this Project, we will call this combined ISO and DSO as Independent Grid Operator ("IGO"). The responsibility of planning and operations, including the dispatch of both the transmission and distribution system, falls to the IGO. It will also determine the investment requirements of both transmission and distribution networks. The utilities will continue to own the transmission and distribution assets, but the operations will be under the IGO.

There are examples of entities that combine traditionally separate roles and functions. For example, in Singapore, the Electricity Market Authority ("EMA") combines three disparate functions: as (i) power systems operator; (ii) industry regulator; and (iii) industry, developer.[72] As a system operator, EMA also conducts system planning to ensure reliability—such planning includes incorporating distributed generation (along with large generation plants) into the power system. This synchronizes well with EMA's functions as a regulator—functions that involve promoting competition and ensuring resource adequacy.

The role of the utility would also evolve into that of a DSPP. Under the IGO's oversight, the utilities can establish guidelines for DERs and other service providers so that they can offer grid support services. Utilities can then run competitive solicitations for these services and would only be allowed to provide these services themselves if third-party providers failed to beat the utilities' cost benchmarks. The IGO's independence will help ensure that the evaluation criteria for such

[72] Energy Market Authority. *Our Roles.* Web. <https://www.ema.gov.sg/Our_Roles.aspx>

solicitations will not be designed to deliberately favor any potential offeror, including the utility. Utilities and IGO can devise a compensation scheme for these services such that ratepayers would bear lower costs compared with instances (under the previous model) when they rely on traditional utility solutions (such as infrastructure upgrades). Utilities will also be allowed to earn additional revenues, either as shared savings from avoided costs to ratepayers or as fees from the third-party providers ("platform revenues," for example).

The components of this hybrid model can be implemented in different stages. The hybrid regime will feature Outcomes-based PBR initially—the IGO's functions such as the overseeing of reliability and interconnection and the DSPP's role in leveraging DERs for grid services (to lower costs to ratepayers) can be incorporated as outcomes and metrics within the PBR framework. When the IGO is introduced, reliability and interconnection targets can be removed from utility ratemaking. It may be prudent to add the DSPP component last, or at least not before the IGO, as it is the most complex component and the intervening years can shed more light on the enabling technologies and business models.

Indeed, it may even be more advantageous to implement such a combined model. The proposed hybrid model will likely ***be more effective in meeting the State's goals.*** It will be more effective in enabling a competitive distribution system and addressing conflicts of interest than just a "pure" PBR model. Furthermore, ***fewer incentive mechanisms would be necessary under such a hybrid model*** because the IGO and the utilities' role as a DSPP would make it unnecessary to include incentives (such as for those related to reliability, DER interconnection, or competitive procurement) for the utility. In such a scenario, the proposed IGO would likely address those criteria by its independence and mandates. Therefore, the focus of the incentives under PBR can be directed to where they will be most effective, for example, on lowering costs and aligning the utility's incentives with the State's energy goals.

A staggered implementation can also help lower the transition costs of this hybrid model and make them more predictable. The costs of a DSPP model will be better understood because lessons from other jurisdiction regarding implementation, technology, and business models can be adapted to Hawaii. There is more time to conduct the necessary analyses, so the State can fully understand all costs and benefits and ensure that it is implemented correctly. The additional time can also allow the completion of any needed legislative processes.

A significant downside is a potential need to pass legislation and regulations, to create the mandate and authority for such a new entity unless the parties can voluntarily reach an agreement.

7 Lighter regulation for KIUC

Electric cooperatives ("co-op") such as KIUC are owned by their customers, who are also referred to as "members" of the co-op. On November 2002, KIUC became the first electric co-op in Hawaii when it purchased the electric assets on Kauai from Citizens Communications. Any individual, partnership, joint venture, corporation, limited liability company, political entity, or other person or legal entity that has agreed to purchase or purchases electric energy from KIUC is eligible for membership in the co-op.[73]

KIUC's decision-making process is indirectly controlled by its members through the Board of Directors, who are elected by the members on a "one member, one vote" basis.[74] Candidates receiving the highest number of votes from members during the voting period for the number of positions being filled will be declared as elected regardless of the number of votes cast. Tie votes are decided by a coin flip conducted by a Circuit or District Judge. In the most recent board members election, three seats were vacant, with six nominees, one of whom was nominated by petition. The winning nominees were selected with a 19% voter turnout and the petitioned nominee finishing fourth.[75]

The co-op members' equity interest in KIUC and their ability to hold KIUC's leadership accountable theoretically helps ensure that KIUC's decisions reflect the interests of most voters. Therefore, the following two of the six criteria used to evaluate the various regulatory models are not as relevant to KIUC:

- Maximize consumer cost savings – KIUC members' ownership stake in the utility and their voting rights already provide the potential for oversight of KIUC efforts toward a cost-minimization approach in planning and operations.

- Address conflicts of interests – any profits generated by KIUC are returned to its members in the form of patronage capital and efforts in resolving the conflict of interest that usually exists between utility shareholders and ratepayers in IOUs. Likewise, KIUC has less incentive to discriminate against IPPs if they are competitive with utility-owned generation. However, it must be noted that the co-op model may not itself provide oversight of conflicts of interest within its management.

While the other IOUs remain in compliance, it is noteworthy that KIUC is currently ahead of the IOUs in meeting state energy goals. As mentioned in Section 5.1, KIUC achieved 44.4% of net electricity sales from renewable energy and demand-side management in 2017; the corresponding

---

[73] Kauai Island Utility Cooperative. *Seventh Revised and Restated By-Laws of Kauai Island Utility Cooperative.* Accessed at: <http://website.kiuc.coop/content/bylaws> on June 13th, 2018.

[74] KIUC. *About Us – Cooperative Principles.* Web. <http://website.kiuc.coop/content/cooperative-principles>

[75] Note that candidates are nominated by a Nominating Committee, that is chaired by a sitting Director, not due for re-election. Candidates can also be nominated by petition, via submission of a petition signed by 35 KIUC members in good standing. (Source: Kauai Island Utility Cooperative. *KIUC Board Election Results.* March 2018. Accessed at: < http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/pr/pr2018-0310-election.pdf>)

proportion for HECO Companies was 25.8%. KIUC has committed to further expansion of its portfolio of renewables so it can reduce the fuel costs of its oil-fired plants. As of 2016 (the most recent year for which complete data is available), KIUC's residential customers paid the highest rates relative to other counties, with average rates of 34¢/kWh in 2016. This is compared to 26¢/kWh paid by HECO residential customers, the lowest among the HECO companies.[76] Provided Kauai County residents share the state policymakers' desire to transition to renewable energy; they can also pressure the KIUC leadership to continue expanding the penetration of renewables.

As described in the Task 2.1.1 report, the lighter regulation model will relieve KIUC of the requirement to obtain PUC approval for rates and rate design, contracts with fuel and power suppliers, and capex. Under lighter regulation from the PUC, KIUC would be exempted from certain regulations—such as those for approval of rate setting and design, power purchase agreements with IPPs, fuel contracts, and large capital expenditures—established based on an IOU structure, if such transactions or activities would not exceed particular thresholds.

However, such thresholds regarding rate increases and capital expenditures would be put in place to trigger a review by the PUC. Specific triggers could be designed to reinstate PUC's regulation, e.g., for projects or rates above a certain threshold or customer disputes above a certain amount. However, the exact metrics must be developed carefully. An indicative approach to the development of triggers could include, but are not limited to:

- Seeking of approval if KIUC wishes to pay a salary higher than HECO Companies for any similar position;

- The opening of PUC investigation in the following events (or similar cases):

    - When rate increases exceed the higher of 5% or 2 times State consumer price index ("CPI"), and 5[x] or more ratepayers object to PUC, PUC may open investigation;

    - If ratepayers provide evidence of rate discrimination; and

    - If the customer has exhausted KIUC internal dispute resolution processes and continues to feel KIUC has acted contrary to their policies, PUC guidelines, or the State law.

KIUC's Board of Directors would continue to approve operating and capital budget, develop resource plans—considering the interest of the members and ensuring adequacy of electricity. The Board's decision-making, however, would be subject to protest and would trigger a review if they are deemed to violate cost causation principles. Similarly, protections would remain in

---

[76] Sources: HECO Companies website. *Rates and Regulations – Average price of electricity.* Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity>; KIUC. *"KIUC Miscellaneous Data 2012-2016." Annual Report to the PUC (December 31, 2016).* PDF page 47.

place for any perceived self-dealing and severe deviation from accepted management practices. Moreover, the state energy goals will still apply to KIUC.

The most significant benefit of a reduced oversight model is cost savings for KIUC. Regulatory proceedings are expensive and can extend for more than a year. KIUC must commit personnel to prepare materials for filings, engage with stakeholders, and hire outside consultants on legal and financial matters. For example, during rate cases, the costs to KIUC can be more than $3 million a year or over $81 per customer per year.[77] Without the direct PUC oversight, the utility can prioritize its resources and savings can be passed down to KIUC members instead.

A reduction in regulatory burden can increase operational flexibility for KIUC. Currently, KIUC requires PUC approval before it can introduce new rate designs or even raise rates. Given the costs of a rate case, it may refrain from filing with the PUC even if doing so may benefit both the utility and its members. Reducing PUC's regulatory requirements for KIUC allows the co-op to introduce innovative programs and rate designs if its board approves them.

A significant drawback of this model is that it becomes more challenging to align KIUC's corporate direction with state policy goals. KIUC's members and board both agree with Hawaii's 100% renewables target, but this may change in the future (however unlikely that may appear at present). Hawaii's legislature may also introduce other policies in the future that are relevant to electric utilities—policies such as targets for battery storage and electrifying transportation or regarding charging infrastructure for electric vehicles. A lack of direct PUC regulation will leave state authorities with fewer tools at their disposal to ensure that KIUC will comply with their policy goals.

This scenario is currently unfolding in a Virginia co-op. Members of the Rappahannock Electric Cooperative have filed a petition against their co-op with the Virginia State Corporation Commission. Their dissatisfaction stems from bylaws—adopted by the co-op's board of directors—that they believe are inconsistent with the co-op's founding principles.[78] While the complainants are in the minority, the incident illustrates an example of the need for external oversight for a co-op board.

The PUC also plays the role of a mediator if KIUC's members are dissatisfied with the utility leadership. While members can raise matters with the board and trigger an election, they may still be out-voted. Similarly, the absence of PUC oversight may result in the principal-agent problem, where management engages in self-dealing. This includes the incentive for top management to award themselves high salaries, cronyism for jobs, and rate design that favors strong lobby constituents or rate classes. In such cases, they will have no recourse without PUC regulation. As an objective body, the PUC is well-suited to mediate in disputes over rates or other policies that disproportionately harm a minority of KIUC members.

---

[77] Project Team's meeting with Ben Sullivan and Hermina Morita on Kauai Island. June 15, 2018.

[78] SNL. "Va. Co-op members file legal challenge in fight for control" July 27, 2018. Web. Accessed August 5, 2018.

Another factor is the PUC's reliance on fees—from Hawaii's utilities—to meet its overhead expenses. PUC fees will presumably be waived for KIUC if the latter is removed from the former's regulatory authority. Currently, utilities are charged 0.5% of gross annual revenues for PUC fees.[79] KIUC's gross revenue was $147.8 million in 2017, resulting in estimated PUC fees of about $0.74 million.[80] This would be a small but significant loss of income for the PUC because it derived 89.8% of its funding from charges in the fiscal year 2017 (July 2016 to June 2017), of which KIUC fees comprised 3.9%.[81] This can impact the PUC's ability to carry out its functions in regulating other electric, gas, water, waste, and telecom utilities that remain under its jurisdiction. Lighter regulation of KIUC may not necessarily decrease the PUC's staffing needs and expenses because it is the smallest of Hawaii's electric utilities. Therefore, it could result in higher fees for other utilities.

[79] HRS §269-30. Finances; public utility fee. <http://www.capitol.hawaii.gov/hrscurrent/vol05_ch0261-0319/hrs0269/hrs_0269-0030.htm>

[80] Moss Adams. *Report of Independent Auditors and Consolidated Financial Statements – Kauai Island Utility Cooperative. December 31, 2017 and 2016*. April 2018.

[81] Hawaii Public Utilities Commission. *Annual Report for Fiscal Year 2017.* December 2017.

8 Steps required in forming the regulatory model

This section provides a list of steps necessary in establishing the proposed regulatory model. As discussed below, all the necessary steps in the establishment require actions led by the Hawaii PUC. If a new entity like HERA or ISO is established, certain types of surcharge and independent new hires will be needed. The role of utilities will change as the new regulatory model is developed. For instance, if an ISO is set up in Hawaii, it needs to acquire monitoring and dispatching functions and facilities from the utilities. If the distribution-focused regulatory model is selected, the utilities will shift their roles, for example, to act as distribution system platform providers instead of owners of DERs. Among the regulatory models studied, it seems like the distribution-focused regulatory model will be the most challenging to implement because of the presumed generation regulatory evolution, required responsibility transformation of utilities, and increased workload for the PUC.

8.1 Status quo with increased oversight[82]

As discussed earlier, there is already a law for the formation of the HERA. Setting up the HERA will be the next step. These steps include:

- ✓ The Hawaii PUC establishes qualification requirements for HERA by rule or order
- ✓ PUC details the scope of HERA activities
- ✓ The entity that will implement the HERA should be determined by the Hawaii PUC via competitive bid, scored request for proposal, or sole source procurement in certain situations (based on HRS 103D)
- ✓ The PUC orders that Hawaii electricity reliability surcharge will be collected to support the operations of HERA
- ✓ The HERA will hire staff members with appropriate skills and level of independence to develop and review reliability standards and interconnection requirements
- ✓ Once established, the HERA will review matters concerning reliability and interconnection and report to the Hawaii PUC on its operational and financial position annually

Moreover, as discussed earlier, there are some similarities between HERA and NERC. The textbox below provides a short discussion on the establishment of NERC. However, it should be noted that NERC's responsibility spans the continental US, Canada, and the northern

[82] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui*. August 25, 2017. Page 63.

portion of Baja California, Mexico[83] while HERA would be a much smaller organization covering the State of Hawaii only.

North American Electric Reliability Corporation ("NERC")

In November 1965, 30 million customers lost power in the US and Canada—this was the largest blackout to date in history. The US Electric Power Reliability Act proposed to create a council on power coordination in 1967. This stimulated the development of an industry electric reliability council. In response to the 1965 blackout and the recommendations of the Federal Power Commission (predecessor of the FERC), NERC was established by the electricity industry in June 1968.

In 1992, in one of six Agreements in Principle adopted by the Board, NERC Board of Trustees stated for the first time that conformity to NERC and regional reliability policies, criteria and guides should be ***mandatory*** to ensure reliability. The year after (1993), NERC published "NERC 2000", which built on the Agreement in Principle. It is a four-part action plan that recommends mandatory compliance with NERC policies, criteria, and guides and a process for addressing violations.

In response to FERC's Notice of Proposed Rulemaking on Open Access ("NOPR"), NERC filed six-point action plan in 1995 to address the planning and operating reliability aspects of the NOPR.

In 1997, the Electric System Reliability Task Force (established by the Department of Energy) and an independent Electric Reliability Panel ("Blue Ribbon" Panel, formed by NERC) determined grid reliability rules must be mandatory and enforceable in an increasingly competitive marketplace.

Proposed reliability legislation that would create an ***electric reliability organization*** was first introduced in US Congress by Senator Slade Gorton of Washington in 2000. In August 2005, Energy Policy Act of 2005 authorized the creation of an audited self-regulatory electric reliability organization and stated that compliance with Reliability Standards would be mandatory and enforceable.

In 2006, FERC certified NERC as the electric reliability organization for the US. The next year (2007), FERC approved 83 NERC Reliability Standards, the first set of ***legally enforceable standards*** for the US Bulk-Power System.

Currently, NERC's responsibilities include:

- development and enforcement of Reliability Standards,
- annual assessment of seasonal and long-term reliability,
- monitoring of the bulk power system through system awareness, and,
- education, training, and certification of industry personnel.

Source: NERC. *History of NERC.* August 2013.

8.2 Independent system operator

There are several steps in establishing an ISO, based on the experience of other ISOs/RTOs in North America. Below are some of the standard steps in its establishment:

- ✓ The PUC directs the establishment of an ISO, a non-profit third-party organization that can oversee equal access to the power grid
- ✓ The ISO forms a Board of Directors to oversee ISO operations, approve budget and staffing, establish market rules, and approve subsequent changes
- ✓ The ISO acquires or leases existing dispatch, monitoring, and control equipment, and hires staff[84] with appropriate skills in managing transmission/distribution system
- ✓ The ISO develops market rules, establishes stakeholder committees, and delineates PUC-ISO relationship
- ✓ The ISO, through stakeholder meetings, develops ISO tariff

The ISO develops market protocols through stakeholder collaboration. Potential market protocols include but are not limited to: energy scheduling and dispatch; ancillary services; congestion management; outage coordination; settlement and billing; metering; data acquisition and aggregation; market information systems; transmission and distribution losses; registration and qualification; and market data collection, among others.

ERCOT[85] became the first ISO in the US in 1996. The textbox below provides a timeline of the formation of ERCOT. It is worth noting that, from 1999 to 2000, ERCOT developed market protocols (including rules and standards for energy scheduling and dispatch, ancillary services, congestion management, outage coordination, settlement and billing, transmission and distribution losses, market data collection, etc.) through stakeholder collaboration.

---

[84] Assets and staff could be transferred from utilities.

[85] Like Hawaii, ERCOT has no connections across state lines, so it is considered as "intrastate" and out of the jurisdiction of FERC.

Formation of the Electric Reliability Council of Texas ("ERCOT")

1941

- To aid war effort, Texas utilities banded together to form the **Texas Interconnected System** ("TIS") .

1970

- ERCOT was formed by the TIS to comply with **North American Electric Reliability Corporation ("NERC") requirements**.

1981

- All operating functions of the TIS were transferred to ERCOT, and ERCOT became the **central operating coordinator** for Texas.

1986

- ERCOT opened its **first office** and hired four full-time employees.

1995

- The Public Utility Regulatory Act was amended by the Texas Legislature to **deregulate the wholesale generation market**. The Public Utility Commission of Texas began process of expanding ERCOT's responsibilities to enable wholesale competition and facilitate efficient use of the power grid by all market participants.

1996

- On August 21, the PUC of Texas endorsed an electric utility joint task force recommendation that mandates ERCOT to become an ISO that can ensure an impartial, third-party organization to oversee equitable access to the power grid among the competitive market participants.
- This change was officially implemented on September 11, when the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO, making it the **first electric utility industry ISO** in the US.

1999

- On May 21, the Texas Legislature passed Senate Bill 7 (SB 7) which required the creation of a **competitive retail electricity market** to give customers the ability to choose their retail electric providers, starting January 1, 2002.

Source: ERCOT. *Company profile – History.*

8.3 Distribution-focused regulatory model

As described in Task 1 (Ownership models), moving to an integrated distribution-focused regulatory model necessitates piloting new and different ways in operating the electricity system and working with third-party DER providers. It also requires having a different business model for the utility.

Steps in implementing the distribution-focused regulatory model include the following:

- ✓ The Hawaii PUC reviews the existing regulatory model and engages stakeholders in discussing and determining the definition of DSPP or DSO and how it will work[86]
- ✓ The Hawaii PUC orders that utilities to take on the new role of the DSPP
- ✓ The Hawaii PUC reviews the existing ratemaking approach and revises items, i.e., providing incentives to the utilities so they can support efficient DER integration, in line with their new role
- ✓ The DSO develops a distribution use of system charge that will facilitate wheeling within the distribution system
- ✓ The DSO installs independent board to oversee the DSO function
- ✓ The DSO identifies required additional technology in the implementation of DSPP and plans in financing and installation/establishment
- ✓ The DSO recruits employees who are not being seconded from the utility [applies to the IDSO only]
- ✓ The utilities file their DSIP including self-assessment of abilities in integrating distributed resources and their five-year roadmap to the PUC

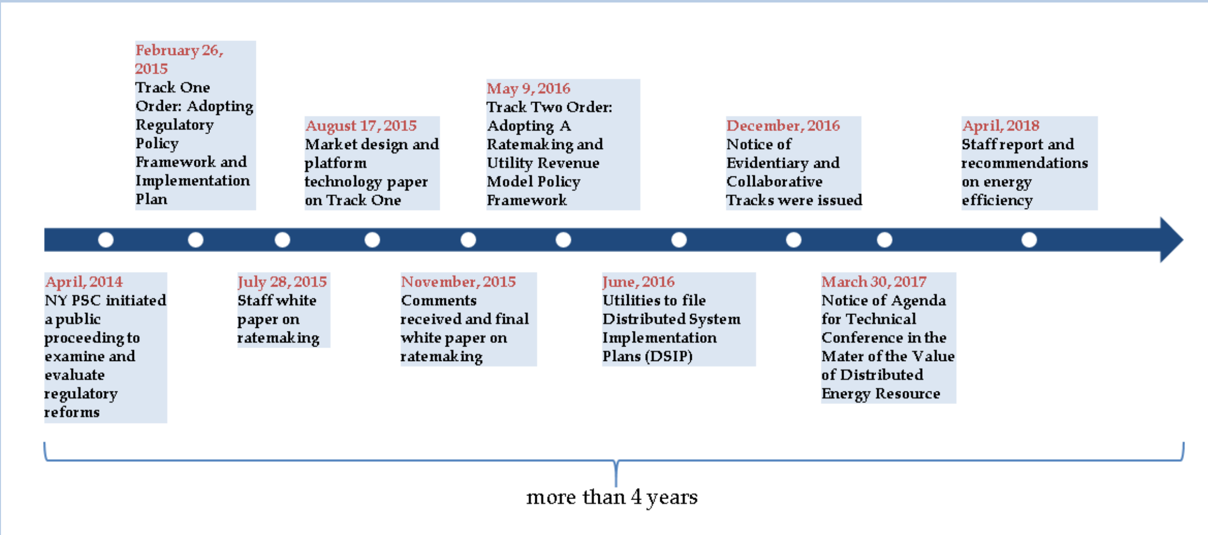
In New York's REV proceeding, it took more than two years for the PSC to issue the Track Two Order, which serves as the foundational document regarding the utilities' revenue model. As of August 2018, it has been over four years since the PSC initiated the REV proceeding. Utilities are still in the process of adding details to their distributed system implementation plans, exploring opportunities for non-wires alternatives, and conducting pilots and demonstration projects with private sector industry participants. The textbox below shows the timeline of the New York REV experience.

---

[86] This process could be lengthy, given REV's experience (as shown in the textbox below).

Timeline of REV in New York

Through Governor Cuomo's *Reforming the Energy Vision* initiative, utilities in the New York State have been under regulatory reform and business model evolution. As of August 2018, this process has been ongoing for more than four years. The level of activity in the regulatory reform has been intense. Over 180 organizations, including utilities, power providers, non-profits, government agencies, etc., have filed more than a thousand documents regarding the initiative.



Source: NY. *DPS - Reforming the Energy Vision*. Makholm, Jeff. "The REVolution yields to a more familiar path: New York's Reforming the Energy Vision." *The Electricity Journal*. Volume 29. Issue 9, November 2016.

8.4 PBR

Moving from a traditional COS to PBR can be a huge task not only for the regulator but also for the utilities as well. It involves significant regulatory work and requires stakeholdering to determine the appropriate PBR mechanism that can be implemented and will allow more in-depth analysis of sectoral and technical issues (discussions of which are not always present or as thoroughly dissected during a COS deliberation). Nevertheless, as discussed earlier, Hawaii can learn from the experiences of jurisdictions that are currently under PBR.

The first 'formal' step in the PBR process is the regulator's expression of intent to implement a shift. In this step, the regulator is expected to explain the objectives clearly to all stakeholders as it embarks on the process. For example, in the case of Alberta, the Commission highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies to improve their efficiency while ensuring that the benefits from the increase in efficiency will ultimately benefit customers.[87]

[87] Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237. September 12, 2012. P. 5. Website. <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

Experience and best practices dictate that the shift to a PBR mechanism requires the enumeration of principles that should guide the stakeholders (particularly the utilities) in the development and implementation process. The establishment of principles will assist the regulator in the evaluation of and deliberation on the PBR proposals. Such principles should also guide the utilities in developing the most responsive and relevant proposals. Below are the high-level steps in the transition to PBR:

- ✓ The regulator reviews the current ratemaking and regulatory model, announces intent to go into PBR, and releases indicative schedule for its implementation
- ✓ The regulator provides PBR educational seminars and stakeholder consultation workshops
- ✓ The regulator develops and releases proposed guiding principles for the PBR and stakeholders provide inputs to these principles
- ✓ Regulator finalizes and issues the PBR guiding principles and the regulatory implementation guidelines, which detail the type of PBR framework to be used, regulatory term (e.g., for three years), format of the PBR Plan, and documentation/evidence that is needed to be submitted to the PUC
- ✓ Utilities prepare their PBR plan and provide to the regulator
- ✓ Regulator reviews the PBR plan
- ✓ Interveners submit information requests and utilities submit information responses; oral hearings; utilities submit arguments
- ✓ Regulator issues its PBR decision

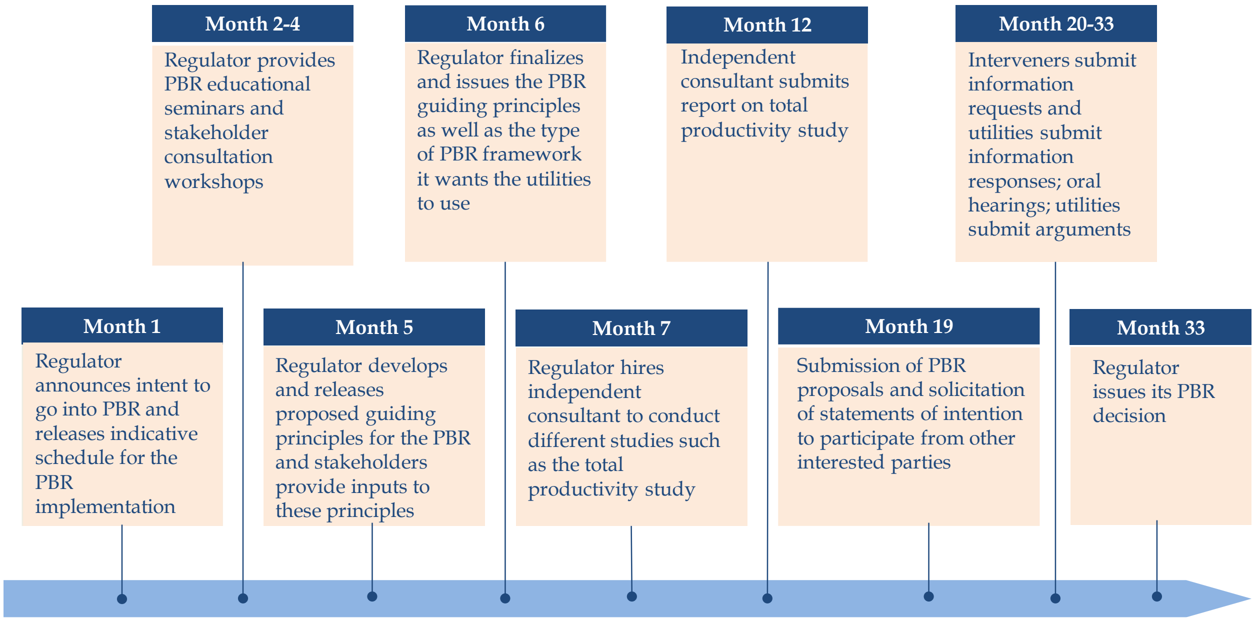
The shift to PBR often involves the steps and typical timelines that are shown in Figure 20.[88] This timeline is for a PBR launch; the timing could be less for the succeeding regulatory period. More detailed examples of two jurisdictions' move to PBR are provided in the textboxes below. As the experiences show, approximately one to three years are typically required.

Finally, data availability is a critical element in the development of a PBR regime and will improve the functionality of PBR regulation over time. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. "Harder" forms of PBR require collating and employing multi-period information and data samples covering multiple firms. Over time, availability of reliable, comparable, and accurate data for the industry as a whole and the utilization of "best practice" forecasting tools can improve the functionality of the PBR

[88] This list is mostly adopted from the chronology of events involved in the shift to PBR of Alberta. Note, however, that the steps and timeline in this list are indicative only and depend on various factors such as government regulations, timely submission of reports and proposals, number of utilities and interveners, and strong consumer opposition or involvement, to name a few.

process, thereby, facilitating analysis and negotiations of parameters for PBR factors, as well as benchmarking actual productivity achieved against prior targets.

Figure 20. Move to PBR steps and timeline (Alberta experience)



Source: AUC Decision 2012-237.
Note: The timeline above is based on the experience of Alberta (except ENMAX) during the regulatory proceeding for the distribution utilities.

Ontario's move to PBR

In anticipation of the Energy Competition Act of 1998 (Bill 35) being passed, the Ontario Energy Board ("Board" or "OEB") stated its intent in October 1998 to consider PBR as a new approach to regulation. The first step undertaken by the Board toward the establishment of a framework for guidelines on PBR was the holding of a series of seminars in October and November of 1998 to familiarize stakeholders with the concept. Stakeholders were able to provide input for the most appropriate approach in PBR for electricity distribution. These inputs were compiled into a report (issued in December 1998), provides guidance to the Board going forward.

Four task forces—coordinated by Board staff—were then established to address the following topics: cap mechanism, yardstick mechanism, implementation, and distribution rates. These task forces consisted of 83 volunteer stakeholder members representing various electricity distributors, gas utilities, customer groups, and special interest groups. Task force meetings were conducted from mid-January 1999 through April 1999.

In the process, technical expertise on PBR and industry restructuring were provided to assist the task force. To address the diversity and large number of emerging issues on PBR and restructuring in general, working groups were formed within each of the task forces. The reports produced by these working groups were compiled by Board staff into task force reports and issued in mid-May 1999. Individual task force member position papers were included as appendices to the task force reports. To provide updates on the process to members who were not participating in the task forces, a web site was set up by the Board.

A draft of the *Board Staff Proposed Electric Distribution Rate Handbook* ("the draft Rate Handbook") was distributed on June 30, 1999. This draft document contains a proposal for a regulatory framework, which the Board used in developing and administering electricity distribution rates in the Province. Regional seminars were held across Ontario to provide stakeholders with an understanding and clarification of the proposal.

The draft Rate Handbook contained proposed rate policies, guidelines, and procedures, which were used by the Board in the establishment and adjustment of electricity distribution rates in Ontario for a first generation PBR plan. A series of presentations and a technical conference were held to discuss the draft Handbook.

On January 2000, the Board decided on a price cap framework. The proposed plan had a three-year term (2000-2002). The process—a bit over one year—is shorter than in Alberta.

Source: OEB website.

Illinois' move to PBR

The State of Illinois presents another example of a jurisdiction that has implemented a performance incentive mechanism ("PIM")-oriented PBR. The Energy Infrastructure Modernization Act ("EIMA") was signed into law on October 26, 2011. The EIMA provided a framework through which participating utilities could opt to recover electric delivery service costs through a performance-based formula rate provided that the participating utilities would also commit to undertake the infrastructure investment program as well as customer assistance programs as specified in Illinois Compiled Statutes ("ILCS") 5/16-108.5. Commonwealth Edison ("ComEd") and Ameren Illinois Company ("Ameren Illinois") opted to participate, thus, regulated by the Illinois Commerce Commission ("ICC").

The law not only authorized the smart grid investment but also set reliability and various performance metrics that must be achieved over the ten-year period (2012-2021). To assure that consumers would benefit from this change, the law set forth the following metrics:

- 20% improvement in the System Average Interruption Duration Index ("SAIDI");
- 15% improvement in the Customer Average Interruption Duration Index ("CAIDI");
- 20% improvement in the System Average Interruption Frequency Index ("SAIFI");
- 75% improvement in the total number of customers who exceed the service reliability targets;
- 90% reduction in issuance of estimated electric bills;
- 90% reduction in consumption on inactive meters;
- 50% reduction in unaccounted for energy (i.e. non-technical line loss); and
- $30,000,000 reduction in uncollectible expense.

These metrics were established as penalty-only performance incentives, where progress was required in equal segments over a ten-year period. Put differently, each year the participating utility does not meet the set goal, it faces a penalty of a return-on-equity ("ROE") reduction of 5 basis points in years 1 through 3, 6 basis points in years 4 through 6, and 7 basis points in years 7 through 10. To avoid a penalty, the participating utility must achieve full progress on reliability goals and 95% progress on other goals (220 ILCS 5/16-108.5).

Nonetheless, environmental and consumer groups were not satisfied with these performance metrics as they failed to address several other benefits of smart grid investments. Stakeholder discussions ultimately resulted in an agreement in 2013 between the groups and ComEd, approved by the ICC, whereby additional performance metrics to be tracked were added to the list, including (but not limited to) the following: reductions in greenhouse gas ("GHG") emissions; load served by distributed energy resources ("DERs"); time required to connect DERs to the grid; peak load reduction through demand response ("DR"); and customers enrolled in time-varying rates. While these additional performance metrics did not result in penalties or rewards, they did allow regulators and stakeholders to assess the investment's benefits. Overall, over sixty performance metrics were developed.

Source: Illinois Commerce Commission; 220 ILCS 5/16-108.5; NREL & RAP.

9 Appendix A: Scope of work to which this deliverable responds

Task 2.2.1 Comparative review of regulatory models, including a high-level process assessment.

CONTRACTOR shall provide a comparison of the regulatory models: 1) how they are similar to and/or different from each other; 2) the relative advantages and disadvantages of each, and 3) the steps required for their formation.[89] Evaluate each model's ability to: (a) achieve State energy goals; (b) maximize consumer cost savings; (c) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (d) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (e) align management, ownership and ratepayer interests.

DELIVERABLE FOR TASK 2.2.1. CONTRACTOR shall provide its conclusions and all work related to providing a comparative review of the regulatory models including a high-level process assessment. CONTRACTOR shall include an assessment of each model by various criteria, an assessment of the pros and cons of these models from Hawaii's perspective, and steps required to transition to each regulatory model. CONTRACTOR shall then evaluate each regulatory model's potential to 1) achieve state energy goals, 2) maximize customer cost savings, 3) enable a competitive distribution system, and 4) reduce conflicts of interest in energy resource planning, delivery, and regulation. CONTRACTOR shall assess each regulatory model from three perspectives: management, ownership, and ratepayer interests. CONTRACTOR shall provide a document in MS Word which summarizes the above and a PowerPoint presentation. CONTRACTOR shall submit deliverable for TASK 2.2.1 to the STATE for approval.

[89] We want to note that we have provided a discussion on this in Task 2.1.1.k 2.

10 Appendix B: List of works consulted

Administrative Rules. Chapter 6-60-4 – Standards for Electric and Gas Utility Service.

Alberta Utilities Commission. *Rate Regulation Initiative Decision 2012-237.* September 12, 2012.

Dawson, Kelly and McAlister, Levi. "Restoring Faith in the Bulk-Power System: An early Assessment of Mandatory Reliability Standards." *The Electricity Journal* 23.2 (March 2010): P. 19-20.

DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

DEBDT's reply to LEI's question. Schwing, Michael D. RE: Key priorities of a regulatory model. Sent: Monday, February 26, 2018 1:48 PM.

Department of Commerce and Consumer Affairs. *Chapter 601 Rules and Practice and Procedure before the Public Utilities Commission. Subchapter 15 Rulemaking Proceedings*.

DSIRE. Interconnection Standards – Hawaii. Website. <http://programs.dsireusa.org/system/program/detail/989>. Access Date: February 16, 2018.

Edison Electric Institute. *Rate Case Summary*. 2012 and 2013.

Edison Electric Institute. *Rate Case Summary*. Q4 2017 Financial Update.

EIA. *Electric Power Annual 2016.* Revised May 2018.

EIA. *Today in Energy*. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: March 22, 2018.

ERCOT. *Company profile - History.* Website. <http://www.ercot.com/about/profile/history>. Access Date: April 2, 2018.

FERC. Regional Transmission Organizations (Issued December 20, 1999) (Docket No. RM99-2-000; Order No. 2000).

Guernsey. *County of Maui: Analysis of Alternative Forms of Ownership and Alternative Business Models for Maui County's Electric Utility Company*. December 23, 2015.

Hawaii Clean Energy Initiative. *Goals and Objectives – Priorities*. Website. <http://www.hawaiicleanenergyinitiative.org/about-the-hawaii-clean-energy-initiative/goals-and-objectives/>. Access Date: April 19, 2018.

Hawaii House Bill 2525 (2012).

Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015)

Hawaii PUC. *Annual Report for Fiscal Year 2017*. December 2017.

Hawaii PUC. *Goals and Objectives of the Commission*. Website. <http://puc.hawaii.gov/about/goals-objectives/>. Access Date: March 2, 2018.

Hawaii PUC. *Order No. 30371 Relating to Various Matters in RSWG Process (Docket No. 2011-0206)*.

Hawaii PUC. *Order No. 32052 Regarding Integrated Resource Planning (Docket No. 2012-0036).*

Hawaii PUC. *Order No. 32735 Modifying Decoupling Mechanisms and Establishing Briefing Schedule (Docket No. 2013-0141).*

Hawaii PUC. *Order No. 34696 Instituting a Proceeding to Review the Power Supply Improvement Plans for Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company (Docket No. 2014-0183)*.

Hawaii PUC. *Order No. 35075 Providing the Attached Amendments to the Performance Incentive Mechanism and Revenue Balancing Account Tariffs Proposed by the Hawaiian Electric Companies (Docket No. 2013-0141)*. Effective January 1, 2018.

Hawaii PUC. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation (Docket No. 2018-0088)*. April 18, 2018.

Hawaii PUC. *Order Relating to RPS Penalties. (Docket No. 2007-0008).*

Hawaii PUC. *PUC Opens Proceeding to Investigate Performance-Based Regulation for the Hawaiian Electric Companies*. April 18, 2018. Press release. < https://puc.hawaii.gov/wp-content/uploads/2018/04/PUC_Press_Release_PBR_FINAL.pdf>

Hawaii PUC. *Service Quality Reliability Annual Reports*. Website. <http://puc.hawaii.gov/reports/energy-reports/service-quality-reliability-annual-reports/>. Access Date: February 16, 2018.

Hawaii Revised Statues ("HRS") Chapter 269 – Public Utilities Commission.

Hawaii Senate Bill 2787 (2012). <https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm>

Hawaii State Energy Office. *Hawaii's Clean Energy Future.* Website. <https://energy.hawaii.gov/wp-content/uploads/2013/12/HSEO_FactSheet_Feb2017.pdf>. Access Date: March 2, 2018.

Hawaii State Energy Office. State of Hawaii – Energy Policy Directives. Website. <http://energy.hawaii.gov/energypolicy>. Access Date: March 2, 2018.

Hawaii State Energy Office. *Energy Resources Coordinator's Report on the Status and Progress of Clean Energy Initiatives and the Energy Security Special Fund*. December 2017.

Hawaii State Legislature. *House Committee on Energy & Environmental Protection*. Website. <https://www.capitol.hawaii.gov/committeepage.aspx?comm=EEP>. April 19, 2018.

HECO Companies. Decoupling Brochure. Website. <https://www.hawaiianelectric.com/Documents/my_account/decoupling/decoupling_brochure.pdf>. Access Date: February 16, 2018.

HECO Companies. *Power Supply Improvement Plans Update Report, Books 1-4.* December 23, 2016.

HECO Companies. *Rule 14 H – Consistency with IEEE Standards*. Website. <https://www.hawaiianelectric.com/Documents/my_account/rates/hawaiian_electric_rules/14.pdf>.

HECO. *2017 Renewable Portfolio Standard Status Report.* February 2018.

HECO. *Direct Testimonies and Exhibits – Book 9, HECO T-28. In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of General Rate Case and Revised Rate Schedules and Rules. (Docket No. 2016-0328).* December 16, 2016.

HECO. *Key Performance Metrics*. Website. <https://www.hawaiianelectric.com/about-us/key-performance-metrics/financial>. Access Date: February 16, 2018.

HI Rev Stat § 269-92 (2015), Hawaii Senate Bill 198 (December 1, 2011), and Hawaii State Energy Office. Energy Policy. Accessed on July 20, 2017. http://energy.hawaii.gov/energypolicy.

House of Representatives. State of Hawaii. HB 623. Effective July 1, 2015.

"Innovation Opportunities." *REV Connect.* Website. <nyrevconnect.com/innovation-opportunities/>. Access Date: May 17, 2018.

ISO-NE. The ISO's Funding and Budgeting Process. Website <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>. Access Date: April 20, 2018.

Kahn, A.E. *The Economics of Regulation: Principles and Institutions*, Volume 1 (1970) and Volume 2 (1971). Wiley: New York (1970, 1971)

KIUC. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters – Volume 1 (Docket No. 2009-0050).* June 2009.

KIUC. *KIUC Board Sets Renewable Energy Goal of 70 percent by 2030*. February 1, 2017.

KIUC. *KIUC's 2017 Annual Renewable Portfolio Standards ("RPS") Status Report*. March 29, 2018.

KIUC. KIUC Interconnection Process. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/Full%20Application%20Packet.pdf>. Access Date: February 16, 2018.

KIUC. *Schedule "TOU-S"*. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/tariffs/tariff1-tou-s.pdf>. Access Date: March 8, 2018.

KIUC. *Tariffs*. Website. <http://website.kiuc.coop/content/tariffs>. Access Date: February 16, 2018.

Lantz, Björn. "Hybrid Revenue Caps and Incentive Regulation." Energy Economics 30 (2008) 688-695. September 25, 2006. P 688-694.

Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui*. August 25, 2017.

National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. November 2016.

National Association of Regulatory Utility Commissioners. *Performance-Based Regulation for Distribution Utilities*. December 2000.

NERC. *History of NERC.* August 2013.

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding (issued and effective April 25, 2014).

Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

Opus One Solutions. *"Hawaiian Electric and Opus One Collaborate on Grid Modernization. April 18, 2018."* Website. <www.opusonesolutions.com/news/hawaiian-electric-and-opus-one-collaborate-on-grid-modernization>. Access Date: May 17, 2018.

PJM. Governance. Website. <https://learn.pjm.com/pjm-structure/governance.aspx>. Access Date: April 20, 2018.

Reliability Standards Working Group Independent Facilitator's Submittal: Final Report and Certificate of Service. March 13, 2013. Page 4-5.

S&P Global Market Intelligence. *Commissions: Hawaii PUC*. Website. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/commissiondetails?ID=4136041&Type=1&State=HI>. Access Date: March 2, 2018.

Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

Stakeholders' comments on regulatory models in the stakeholders engagement process, including during the kick-off meeting in May 2017, VERGE Hawaii conference in June 2017, and community meetings in October 2017.

"Track Two: REV Financial Mechanisms." *REV Connect.* Website. <https://nyrevconnect.com/rev-briefings/track-two-rev-financial-mechanisms/>. Access Date: May 17, 2018.

US EIA. *State Profile and Energy Estimates: Hawaii*. Website. <https://www.eia.gov/state/analysis.php?sid=HI>. Access Date: March 1, 2018.

Vogelsang, Ingo. "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective." *Journal of Regulatory Economics*.22:1 5-27, 2002. P 8.

Assessment of current markets under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

August 20, 2018

LONDON ECONOMICS

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models to support the State in achieving its energy goals. This document is one of several working papers associated with that engagement. It provides a case study for each of the regulatory models being assessed, including independent system operator ("ISO") model, distribution focused regulatory model, performance-based regulation ("PBR") model, and lighter regulation for KIUC. Also, for the ISO model and the PBR model, the Project Team reviewed three markets that have changed to these models. For the lighter regulation option for KIUC, the Project Team examined three states that have different arrangements for the regulation of generation and transmission cooperatives ("co-ops"). These case studies offer some insights of best practices as well as some lessons learned for Hawaii, which it can consider as it contemplates selecting and transitioning to a new regulatory model.

Table of Contents

Table of Figures

List of acronyms

AER	Australian Energy Regulator
AESO	Alberta Electric System Operator
BCF	Business Carbon Footprint
BETTA	British Electricity Trading Transmission Arrangements
BMCS	Broad Measure of Customer Service
CAISO	California Independent System Operator
Capex	Capital expenditure
CES	Clean Energy Standard
CHP	Combined heat and power
DBEDT	Hawaii Department of Business Economic Development and Tourism
DECC	Department of Energy and Climate Change (UK)
DER	Distributed energy resources
DNOs	Distribution network operators
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Providers
EDF	Électricité de France
EDR	Environmental Discretionary Reward
EIM	Energy Imbalance Market
ENS	Energy Not Supplied
ERC	Energy Regulatory Commission (Philippines)
ERCOT	Electric Reliability Council of Texas
ESCOs	Energy service companies
EUB	Energy and Utilities Board (Alberta)
FERC	Federal Energy Regulatory Commission
GEMA	Gas and Electricity Markets Authority (UK)
GMC	Grid Management Charge
HSE	Health and Safety Executive
IBR	Incentive-based regulation
ICE	Incentive on Connections Engagement
IDER	Integrated distributed energy resources
IESO	Independent Electricity System Operator (Ontario)
IIS	Interruptions Incentive Scheme
IOUs	Investor-owned utilities
IQI	Information Quality Incentive
IRM	Innovation Roll Out Mechanism
ISO	Independent system operator
ISO-NE	Independent System Operator New England

LDR	Losses Discretionary Reward
LEI	London Economics International LLC
MISO	Midcontinent Independent System Operator
NERC	North American Reliability Council
NETA	New Electricity Trading Arrangements
NGET	National Grid Electricity Transmission
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NY PSC	New York Public Service Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
Ofgem	Office of Gas and Electricity Markets (UK)
Opex	Operating expenditure
PBR	Performance-based regulation
PGC	Power generation companies
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PUCT	Public Utility Commission of Texas
REPs	Retail electric providers
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RO	Renewable obligation
RORE	Return on regulatory equity
RPS	Renewable portfolio standards
SECV	Stakeholder Engagement and Consumer Vulnerability
SHETL	Scottish Hydro Electric Transmission Limited
SPP	Southwest Power Pool
SPTL	Scottish Power Transmission Limited
SSE	Scottish and Southern Energy
ST	Suruhanjaya Tenaga
TDSPs	Transmission and distribution service providers
TIS	Texas Interconnected System
TO	Transmission owners
TTC	Time to Connect Incentive
UK	United Kingdom
VoLL	Value of Lost Load

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Task 2.2.2 in the project scope of work, provides an assessment of current markets under each regulatory model, including a case study, analysis, and conclusions. We have also provided examples of jurisdictions that have changed regulatory model in the last 20 years and lessons learned from these markets.

The Project Team has selected the following markets as case study for jurisdictions that are currently implementing the regulatory model: Texas (independent system operator model or "ISO"), New York (distribution-focused regulatory model), and the UK (performance-based regulation model or "PBR") and Alaska (lighter regulation from PUC). Jurisdictions were selected due to their representativeness as well as their similarities with Hawaii. The case studies include background information on the jurisdiction's electricity sector including an overview of the electricity market, the current regulatory framework, history of transition along with recent developments, and lessons learned from these markets. Detailed review and analysis are provided to help the reader better understand each regulatory model and what aspects should be taken into consideration to move to the regulatory model.

The review of markets that have changed or moved to the regulatory models that are being assessed in the last 20 years covers nine jurisdictions. Since there are no other jurisdictions that have entities like HERA or have a full-blown distribution-focused regulatory model, the Project Team focused on the other three alternative models instead. The Project Team reviewed California, Ontario, and Alberta as case studies for the ISO model. Australia, the Philippines, and Malaysia were assessed as case studies for the PBR model. In addition to Alaska, Colorado, and Utah's cases were studied for the lighter regulation model for Kauai Island Utility Cooperative ("KIUC"). These case studies were provided to show that even under the same regulatory model, there are different regimes and arrangements that Hawaii could learn from.

Based on the experience of these jurisdictions, several key findings emerged, which would be useful for Hawaii to keep in mind as it evaluates its options:

- transition to the regulatory model at the right time (avoiding high demand periods) and gradually,
- set appropriate rates to protect both the utilities and the customers,
- provide mechanisms to ensure that capital investments are recouped in a timely manner,
- provide mechanisms to manage risks beyond utilities' control, and,
- put in place mandatory performance standards.

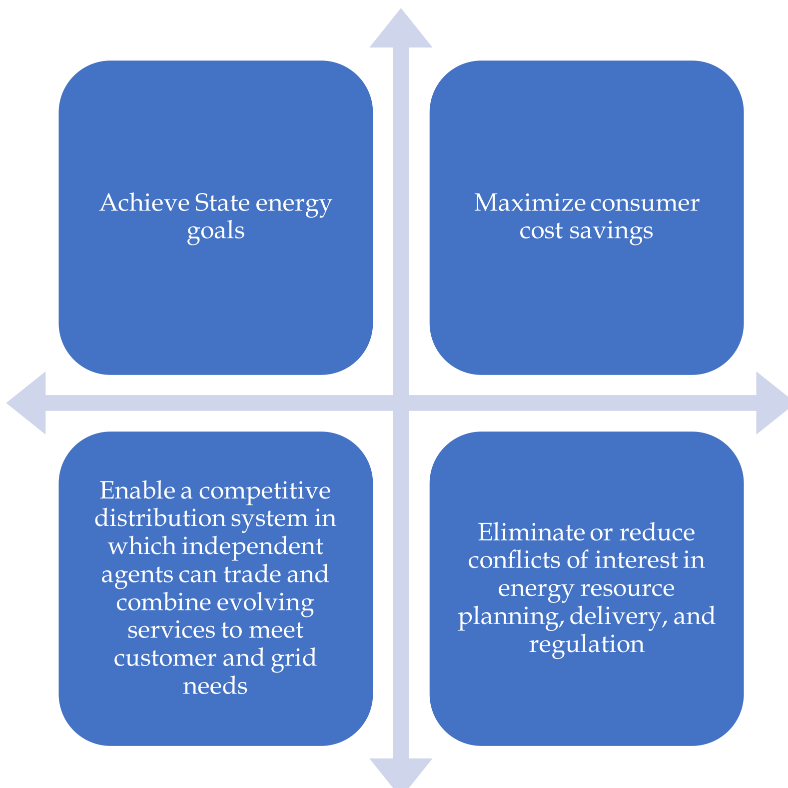
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

---

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 2.2.2 in the project scope of work. It assesses current markets under each regulatory model. The Project Team reviewed examples of current markets under each regulatory model and examples of markets that have changed regulatory model in the last 20 years. Case studies are included to highlight the essential features of different regulatory models and critical issues and lessons from other jurisdictions. Analysis and conclusions of this research are summarized in this memo.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Overview of the case studies

This deliverable presents case studies of current markets under each regulatory model and six jurisdictions that have changed regulatory models. Regulatory models that were examined in this deliverable include independent system operator ("ISO"), distribution-focused regulatory model, performance-based regulation ("PBR") model, and lighter regulation for KIUC.[5]

The case studies provide a detailed assessment of the regulatory models. In particular, the case studies give an overview of the electricity market in that jurisdiction, followed by its current regulatory framework, history of transition to the regulatory model, and recent developments. Finally, each case study presents key takeaways for Hawaii. In addition, the Project Team provides examples of markets that have changed their regulatory model in the last 20 years, including identifying market features such as some utilities, customers served, capacity, annual sales, and retail rates, as data are available. Lessons learned from these markets were provided also discussed in each case study.

3.1 Case selection

The selection of the markets covered in this report is based on a variety of factors as shown in Figure 2. These factors include, but are not limited to, extensive experience with the specified regulatory model, a single-state regulatory structure, similar market size as that of Hawaii, and similar geography as that of Hawaii (i.e., archipelago).

For the markets that are currently under each regulatory model, we chose Texas as a case study for the ISO model because, like Hawaii, it has a single state ISO outside of Federal Energy Regulatory Commission's ("FERC") jurisdiction. New York was chosen as an example for the distribution-focused regulatory model because it is the only pioneer transitioning to this new model right now. The United Kingdom ("UK") has extensive experience in PBR having implemented it for more than two decades. Moreover, UK's "Revenue = Incentives + Innovation + Outputs" ("RIIO") model was also mentioned in the Hawaii PUC's order on PBR as "*one of the best-known examples of PBR in practice.*" [6]

Finally, for markets that have changed regulatory models in the last 20 years, we reviewed the year of establishment of all the ISOs and selected single-state ISOs (other than Texas) and which have other similarities to Hawaii (e.g., California, Ontario, and Alberta). While multiple jurisdictions have implemented PBR, we focused on markets that had similarities to Hawaii – in terms of relative size or island composition (e.g., Australia, the Philippines, and Malaysia).

---

[5] "Status quo with increased oversight" model was not included in this discussion, as currently there is no single-state Electricity Reliability Administrator that is similar to the concept of Hawaii Electricity Reliability Administrator ("HERA").

[6] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

Figure 2. Rationale for selection of the case studies

Jurisdiction	Regulatory model	Rationale for choosing this jurisdiction
Current markets under each regulatory model		
Texas	ISO	Single-state ISO that is in NERC's jurisdiction but out of FERC's jurisdiction
New York	Distributed-focused	A pioneer state that is transitioning to the distributed-focused regulatory model*
UK	PBR	More than two decades of experience in PBR with new PIMs features in RIIO
Alaska	Lighter regulation for co-op	Most of the retail customers are served by co-ops; dominated by vertically-integrated utilities
Markets that have changed regulatory model in the past 20 years		
California	ISO	Single-state ISO that was set up in the past 20 years; aggressive renewable policies and initiatives
Ontario	ISO	Single-province ISO that was set up in the past 20 years; aggressive renewable policies and initiatives
Alberta	ISO	Single-province ISO that was set up in the past 20 years; relatively small market compared to other ISOs
Australia	PBR	An isolated market; under PBR since 1997
The Philippines	PBR	Consisting of islands; only one transmission utility; under PBR since 2003; several distribution utilities that are owned by coops
Malaysia	PBR	Consisting of islands; vertically-integrated utility under PBR; PBR was developed to promote efficiency and service standards, etc.
Colorado/ Utah	Lighter regulation for co-op	Has co-ops with generation but treat them differently from how Alaska treats co-ops with generation

* Currently, there is no jurisdiction that has a full-blown distribution-focused regulatory model.

3.2 Overview of the jurisdictions covered in the case studies.

Regulatory models' transitions are usually jurisdiction-based (at the country or state/provincial level), unlike transitions of ownership models which involves companies only. Since there are many factors, like economic development and population growth, that impact the number of utilities, number of customers, total capacity, annual sales, and retail rates, etc., it makes less sense to compare these numbers before and after the regulatory models' transition, as these factors will not change due to a change in the regulatory model. Therefore, the Project Team focused on the analysis of the development itself but provided the most recent data available (2016) as general background information for the jurisdictions that were evaluated. Figure 3 shows the key energy statistics about select jurisdictions.

Figure 3. Summary of selected jurisdictions

Current markets under each regulatory model

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
Hawaii	Status Quo	4	506,216	2,893	9,445,389	23.87
Texas	ISO	34	11,975,355	103,607	398,661,809	8.43
New York	Distribution-focused	6	693,283	44,513	147,803,038	14.47
UK	PBR	17	28,000,000	78,279	288,129,030	23.21
Alaska	Lighter regulation	8	337,407	2,742	6,123,202	17.93

Markets that have changed regulatory model in the past 20 years

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
California	ISO	14	16,029,429	70,960	284,119,456	14.68
Alberta	ISO/ PBR	11	1,750,000	16,423	79,560,000	8.11
Ontario	ISO/ PBR	71	5,106,528	36,070	130,194,307	12.23
Australia	PBR	21	6,755,510	42,862	196,500,000	19.22
The Philippines	PBR	130	18,519,029	21,423	74,153,000	16.03
Malaysia	PBR	3	9,659,221	26,563	124,709,000	8.66
Colorado	Lighter regulation	6	2,643,315	16,078	54,802,037	9.83
Utah	Lighter regulation	1	1,175,934	8,976	30,179,534	8.72

Notes: 2016 numbers. Average retail rates are in US dollars (1 Euro = 1.19 USD, 1 CAD = 0.78 USD, 1 AUD = 0.75 USD, 1 MYR = 0.26 USD). Different from the ownership model transition, the utility credit rating of each utility in the market is less relevant to the purpose of this regulatory models' review, and thus, was not included in this memo. There are more than 100 utilities in the Philippines because it comprises of more than 7,000 islands. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of transmission and distribution ("T&D") utilities.

Source: EIA. S&P Global. Ofgem. Eurostat. Australian Energy Market Commission. Meralco. TNB. OEB. IESO. Utilities Consumer Advocate, etc.

3.3 Lessons learned from the case studies

Various lessons can be drawn from the case studies under each regulatory model. However, no matter which regulatory model Hawaii's electricity sector will transition to, there are some general lessons learned from other jurisdictions that will be relevant:

- **Transitioning the regulatory model at the right time:** transitioning the regulatory model tends to affect new build or infrastructure investment by utilities due to uncertainty about the final shape of the model. If this postponement happens during a high demand period, it will cause blackouts or even unexpected crisis.

- **Transitioning the regulatory model gradually**: most if not all markets require adequate preparatory and early-stage implementation periods. Mainly for the generation sector, the gradual introduction of competition contributed to a successful transition.[7]

- **Setting appropriate rates to protect both the utilities and the customers**: jurisdictions that have successfully implemented PBR have set rates that enable the utilities to meet their obligations to customers as well as earn sufficient rates of return to support future investments.

- **Providing mechanisms to manage risks beyond utilities' control**: for the ISO model, regulators need to closely monitor the risks and design backup policies to maintain a stable market. For the PBR model, mechanisms such as exogenous factors, flow-through, and reopeners are necessary to manage the utilities' risks that are beyond their control. For the lighter regulation model, the PUC should provide backup designs to co-op members if the board of directors does not act to serve members' interests.

[7] For instance, it took ISO-NE four years to adopt the "standard market design" including features like day-ahead market in 2003, after it implemented the wholesale energy market in 1999.

4 Markets currently under each regulatory model

This section provides a more detailed assessment of the regulatory models and a case study of one jurisdiction under each of the regulatory models. As shown in Figure 4, Texas, New York, and the UK were selected as sample markets that are under ISO model, distribution-focused regulatory model, and PBR model, respectively.

Figure 4. Summary of selected current markets under each regulatory model

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
Hawaii	Status Quo	4	506,216	2,893	9,445,389	23.87
Texas	ISO	34	11,975,355	103,607	398,661,809	8.43
New York	Distribution-focused	6	693,283	44,513	147,803,038	14.47
UK	PBR	17	28,000,000	78,279	288,129,030	23.21
Alaska	Lighter regulation	8	337,407	2,742	6,123,202	17.93

Note: 2016 numbers. UK's retail electricity rates were converted to USD using the 2016 exchange rate. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of T&D utilities.
Source: EIA. Ofgem. Eurostat.

4.1 Independent system operator: Texas

4.1.1 Overview of the Texas market

The Electric Reliability Council of Texas ("ERCOT") is the ISO that operates the transmission grid and administers the wholesale electricity market in most of Texas. The ERCOT controlled area covers 75% of the state's total area[8] and provides energy to 85% of the state's total load.[9] ERCOT operates a nodal real-time balancing market, as well as day-ahead energy and ancillary services co-optimized market, supplemented with hourly reliability unit commitment. The ERCOT market is dominated by natural gas capacity and generation, contributing shares of 62% and 49% respectively, as shown in Figure 5.

[8] Other parts of Texas area are served by utilities belonging to the Southwest Power Pool, the Southeastern Electric Reliability Council, and the Western Electricity Coordinating Council.

[9] LEI. *LEI Semi-annual Regional Market Update and 10-year Energy Forecast: ERCOT.* 3rd Quarter 2017.

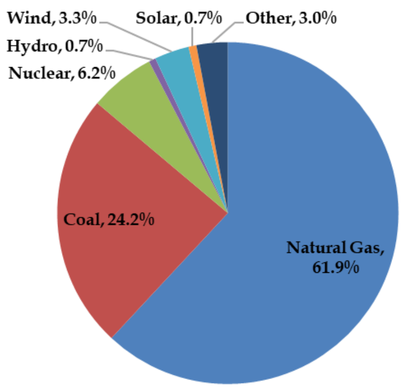
Figure 5. Texas electricity market snapshot

Texas

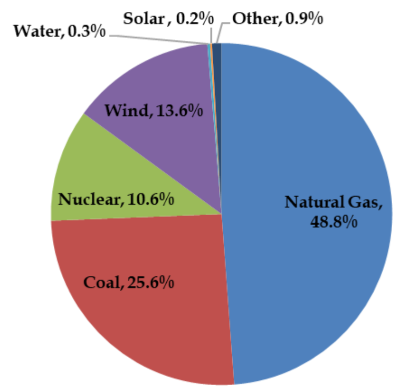
Key facts

Population (2016)	27.9 million
GDP growth (2016)	2.8%
Installed capacity (2016)	103.6 GW
Peak demand (2016)	71.1 GW
Load growth (2012-2016)	1.7%
Generation (2016)	377 TWh
No. of utilities	34

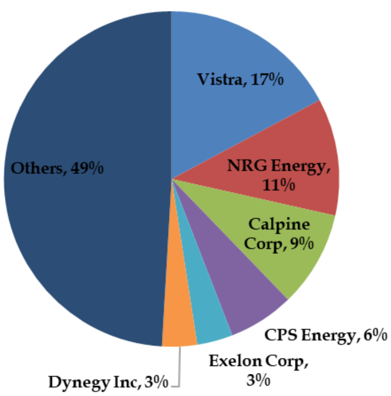
Installed capacity by fuel type (2016)



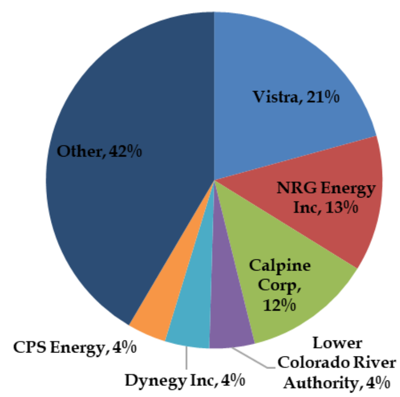
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: The number of utilities refers to the total number of T&D utilities.

Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; S&P Global Market Intelligence. *PUC of Texas. Directory of Transmission & Distribution Utilities.* <https://www.puc.texas.gov/industry/electric/directories/tdu/search_tdu.aspx>

There are 381 power generation companies ("PGCs") currently registered with and regulated by the Public Utility Commission of Texas ("PUCT").[10] As defined by the PUCT, a PGC is *"a person that generates electricity intended to be sold at wholesale and does not own a transmission or distribution facility in [the] state."*[11] Vistra, NRG Energy, and Calpine operate 37% of generating capacity and provide 46% of the energy consumed in ERCOT.[12]

There are 34 transmission and distribution service providers ("TDSPs") in Texas, responsible for owning, maintaining, and operating transmission assets in the State, including IOUs, municipal-owned electric utilities, and co-ops. TDSPs are regulated by the PUCT and are required to provide non-discriminatory access to the grid.[13]

The retail electric market in Texas opened in 2002, brought about by the passage of Senate Bill 7 by the Texas Legislature, which began the project of restructuring the Texas electricity market.[14] There are currently 116 retail electric providers ("REPs") registered with the PUCT.[15] As defined by the PUCT, a REP *"sells electric energy to retail customers in the areas of Texas where the sale of electricity is open to retail competition. A REP buys wholesale electricity, delivery service, and related services, prices electricity for customers, and seeks customers to buy electricity at retail."*[16]

Hawaii and Texas have several similarities that make Texas a good example for the ISO model. For one, ERCOT was established in one single state - Texas, and it is out of FERC's jurisdiction[17] (like Hawaii). Also, similar to Hawaii, Texas has a stand-alone electricity grid which is mostly isolated from the interconnected power systems serving the eastern and western United States.

---

[10] Public Utility Commission of Texas. *Power Generation Companies – Search.* Website. < https://www.puc.texas.gov/industry/electric/directories/pgc/search_pgc.aspx>. Access Date: April 24, 2018.

[11] "Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/pgc/pgc.aspx> Access Date: April 23, 2018.

[12] Third party commercial database.

[13] "Transmission/Distribution Service Providers." *ERCOT.* <http://www.ercot.com/services/rq/tdsp> Access Date: April 23, 2018.

[14] PUCT. *2017 Scope of Competition in Electric Markets in Texas.* January 2017.

[15] PUCT. *Retail Electric Providers.* < https://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx>. Access Date: May 10, 2018.

[16] "Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx> Access Date: April 23, 2018.

[17] According to FERC, "the transmission grid that the ERCOT administers is located solely within the state of Texas and is not synchronously interconnected to the rest of US. The transmission of electric energy occurring wholly within ERCOT is not subject to the Commission's jurisdiction under sections 203, 205, or 206 of the Federal Power Act." Source: FERC. RTO/ISO – ERCOT. Website. <https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp>

contact:
Tianying Lan/Shrutika Sainani
(617) 933-7229
tianying@londoneconomics.com

Moreover, both Hawaii and Texas have observed significant renewable development in the past few years, although the renewable energy development in Texas is mostly driven by favorable wind conditions and easy siting rather than state policy. However, unlike Hawaii, the Texas Reliability Entity ("Texas RE")[18], a Regional Entity, is part of North American Electric Reliability Corporation ("NERC"). There is no Regional Entity in Hawaii. Moreover, the current RPS is not the primary driver for renewables development in Texas, as the 10,000 MW renewable target was met in 2010. Moreover, Texas is much larger than Hawaii in terms of annual sales and peak demand. Hawaii's annual sales in 2016 represented only 2% of Texas' annual sales.[19]

4.1.2 Overview of the regulatory framework in Texas

As mentioned above, ERCOT serves as an ISO, managing the flow of electrical power to 24 million customers[20] in the state of Texas. Governed by a sixteen-member board of directors, subject to oversight from the PUCT and the Texas legislator, ERCOT has members including consumers, cooperatives, generators, power marketers, retail electric providers, IOUs (transmission and distribution providers) and municipal-owned electric utilities.[21] ERCOT's main responsibilities include: (i) ensuring system reliability through planning and operations; (ii) settling the wholesale market for electricity production and delivery; (iii) overseeing the retail switching process for customer choice; and (iv) ensuring open access to transmission.[22]

Unlike other ISOs, which are subject to FERC's oversight, ERCOT operates under the regulation of the PUCT as ERCOT has few connections with the two major US interstate grid systems, the Eastern and the Western Interconnections. The PUCT is responsible for the regulation and oversight of the competitive wholesale and retail electric markets, regulating the State's generation, transmission, and distribution owners.[23] This structure is similar to Hawaii's current regulatory framework, i.e., out of FERC's jurisdiction but under the PUC's regulation, which implies that an ISO model could be feasible in its current regulatory environment.

---

[18] The Texas RE is a not-for-profit corporation that serves as the Regional Entity for the parts of Texas that is overseen by ERCOT. The Texas RE holds a Delegation Agreement with NERC, approved by FERC, authorizing it to "*develop, monitor, assess, and enforce compliance with NERC Reliability Standards; develop regional standards; [and] assess and periodically report on the reliability and adequacy of the bulk power system.*" The Texas RE is one of eight Regional Entities established to carry out "*compliance monitoring and enforcement activities…on behalf of NERC*", which NERC oversees to ensure "*consistency and fairness*." (Source: "About Us." *Texas RE*. Web. August 10, 2018. <https://www.texasre.org/Pages/About-Us.aspx>; "Regional Entity Compliance Programs." *NERC*. Web. August 10, 2018. <https://www.nerc.com/pa/comp/Pages/Regional-Programs.aspx>)

[19] EIA. *Electricity statistics*. Website. <https://www.eia.gov/electricity/state/>. Access Date: April 24, 2018.

[20] "Electric Power Markets: Texas (ERCOT)." *FERC.* <https://www.ferc.gov/market-oversight/mkt-electric/texas.asp> Access Date: April 23, 2018.

[21] Ibid.

[22] Association of Electric Companies of Texas Inc. *The Wholesale Electric Market in ERCOT*. 2017.

[23] PUCT. "About the PUCT.". <https://www.puc.texas.gov/agency/about/mission.aspx> Access Date: April 23, 2018.

4.1.3 History of transition and recent development

The establishment of ERCOT can be traced back to 1970 when the Texas Interconnected System[24] ("TIS") formed ERCOT to comply with North American Reliability Council's ("NERC") requirements. At that time, ERCOT was staffed by two retired employees from the utilities.[25] In 1981, ERCOT assumed the Central Operating Coordinator role as TIS transferred all operating functions to ERCOT. In 1995, the Texas legislature voted to deregulate the wholesale generation market by amending the Public Utility Regulatory Act. ERCOT's responsibilities were expanded by the PUCT to enable wholesale competition.[26] In 1996, the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO on September 11, 1996. This change made ERCOT the first electric utility industry ISO in the US.

From 1999 to 2000, ERCOT protocols (i.e., how ERCOT's organization supports competitive markets while maintaining the reliability of electric services) were developed through stakeholder collaboration. Rules and standards for implementing market functions include but are not limited to "energy scheduling and dispatch, ancillary services, congestion management, outage coordination, settlement and billing, metering, data acquisition and aggregation, market information systems, transmission and distribution losses, renewable energy credit trading, registration and qualification, market data collection, load profiling and alternative dispute resolution."[27] On July 31, 2001, ten (10) control centers merged into one control center. Under the new electric industry restructuring guidelines, power scheduling was centralized, and ancillary services were procured to ensure reliability. Commercial functions were centralized to "facilitate efficient market operations and enable switching by customers between competitive electricity providers."[28] The competitive retail electric market was launched to allow customers to choose power suppliers on January 1, 2002. This was specifically applied to investor-owned utilities ("IOUs") but allowed municipal utilities and cooperatives to opt-in to participate in the competition.[29] In 2003, the PUCT ordered ERCOT to develop a nodal wholesale market design to improve market and operating efficiencies and the nodal market with features like "locational marginal pricing for generation at more than 8,000 nodes, a day-ahead energy, and ancillary

---

[24] As part of the war effort in 1941, the TIS was created by a number of Texas utilities in order to pool energy and share transmission lines. Texas utilities maintained the TIS after World War II and eventually the organization established two monitoring centers, both located within the control centers in north and south Texas. Source: ERCOT. Company Profile - History.

[25] ERCOT. *Company Profile - History*. Web. <http://www.ercot.com/about/profile/history>. Access Date: May 4, 2018.

[26] Ibid.

[27] Ibid.

[28] Ibid.

[29] Ibid.

services co-optimized market, day-ahead, and hourly reliability-unit commitment, and congestion revenue rights" was launched in December 2010.[30]

Regarding renewables development, by 2006, Texas moved ahead of California as the top wind-producing state.[31] In 2016, grid-scale solar capacity totaled 554 MW, and ERCOT established a new solar forecast to support the reliable integration of this rapidly developing generation source. Moreover, on March 23, 2016, wind served 48.2% of load (a new record).

4.1.4 Implications for Hawaii

There are several lessons from Texas' electricity market ISO experience.

- **The Hawaii PUC could take the lead to set up an ISO, as the state is not under FERC's jurisdiction.** Like the PUCT, the Hawaii PUC could lead the process of establishing an independent, not-for-profit entity. Also, like the PUCT, the Hawaii PUC can have oversight and enforcement authority over the ISO protocols, operating guides, and other binding documents.[32] Furthermore, the Hawaii PUC can approve the resource plans that the ISO puts together.

- **If the Hawaii PUC decided to set up an ISO, the control and dispatch center needs to be acquired.** As mentioned above, an ISO needs to own or lease the control center, dispatch, and monitoring facilities to manage the transmission and distribution system. Currently, utilities own and operate these facilities. If created in Hawaii, the new ISO would need to acquire the equipment from utilities and probably hire former utility employees who are skilled and experienced to perform the technical job. Also, the PUC should set up specific policies to address possible conflict of interests.

- **A state-wide ISO requires more supply-demand coordination among counties.** As illustrated in Task 1.1.3 (Existing generation, transmission, and distribution infrastructure in Hawaii), each county has its generation resource characteristics. A state-wide ISO could continue to operate the dispatching and monitoring of each county's market separately or merge the control centers into one. If the ISO plans to have one control center, inter-island transmission connection would be required. Based on ERCOT's experience, expanding interconnection within the State could benefit the system as it brings additional supply to meet demand in populated areas. For instance, ERCOT constructed more than 3,600 miles of transmission lines to move its wind generation from the West Texas and Panhandle regions to more populated regions of the ERCOT grid.[33] With the transmission

---

[30] Ibid.

[31] Ibid.

[32] ERCOT. *Compliance in ERCOT*. Website. <http://www.ercot.com/mktrules/compliance>. Access Date: June 28, 2018.

[33] ERCOT. Company Profile - History. Web. <http://www.ercot.com/about/profile/history>. Access Date: May 4, 2018.

construction, wind served more than 48% of the load, which was a record in 2016. Nevertheless, an interconnection of the different islands is unlikely to happen due to cost and environmental concerns. As mentioned in Task 1.1.5, the HECO Companies evaluated the interconnection between Oahu and Maui island, but found that the gross benefits were "*substantially less than the estimated cost of a cable.*"[34]

- **It takes time to go through a stakeholder process to develop ISO's rules and standards.** It took ERCOT almost two years to go through the stakeholder collaboration to set up the rules and standards for its markets.

4.2 Distribution focused regulatory model: New York

4.2.1 Overview of the New York market

The New York electricity market is competitive and very dynamic, with significant regulatory changes underway. As shown in Figure 6, installed capacity in New York ISO ("NYISO") totaled 44,513 MW in 2016.[35] This is more than 15 times of Hawaii's total installed capacity combined. New York's existing generation portfolio is dominated by gas and oil-fueled generating resources, representing approximately 64% of the state's total installed capacity and 44% of total energy generation.[36] These generating assets are required by state regulators to be ready to switch to fuel oil if the natural gas supply is constrained.[37] Nuclear facilities and hydro facilities (both conventional run-of-river and pumped storage) respectively account for 14% and 11% of total capacity.[38]

[34] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-53.

[35] S&P Global Market Intelligence. Regional Summary Statistics. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/summaryStatistics> Access Date: April 17, 2018.

[36] NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

[37] "New York State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/?sid=NY>

[38] NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

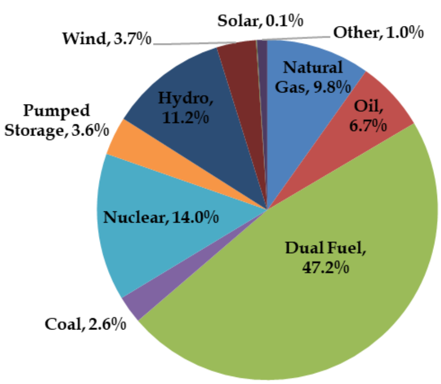
Figure 6. New York electricity market snapshot

New York

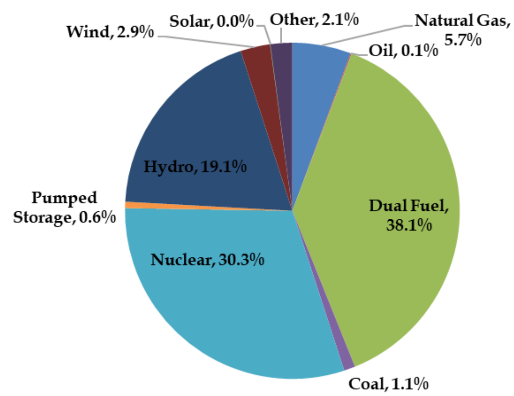
Key facts

Population (2016)	19.8 million
GDP growth (2016)	3.6%
Installed capacity (2016)	44.5 GW
Peak demand (2016)	32.1 GW
Load growth (2012-2016)	-0.3%
Generation (2016)	141 TWh
No. of utilities	6

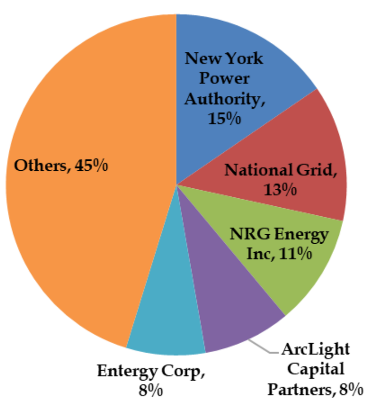
Installed capacity by fuel type (2016)



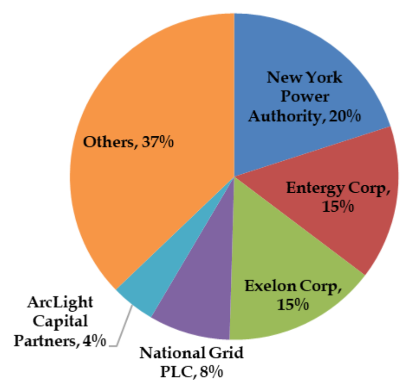
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: The number of utilities refers to the total number of T&D utilities.
Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; S&P Global Market Intelligence; NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017. Department of Public Service. *Electric Utilities Listing.* <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/03627EFC626529EE85257687006F39CD?OpenDocument>

New York electricity generators include both regulated electric utilities and independent power producers with diverse energy sources of generation.[39] The largest five generation owners in the NYISO market account for approximately 55% of total capacity.[40] The New York Power Authority ("NYPA"), a municipally owned generator and transmission owners, is the largest player in the market, accounting for 15% of the state's installed capacity. Other top generation market players include National Grid, NRG Energy, ArcLight Capital Partners, and Entergy.

Transmission assets are owned by eight (8) transmission owners ("TOs"), including six (6) investor-owned utilities ("IOUs") – Central Hudson Gas & Electric Corporation, Con Edison, Orange & Rockland, National Grid, NYSEG, and Rochester G&E – and two (2) power authorities – NYPA, which operates approximately one-third of the major transmission lines in the State,[41] and PSEG Long Island, which operates the Long Island Power Authority's transmission and distribution system.[42,43] The NYISO is the sole authority responsible for directing the operation of the New York State Power System, and coordinates with each TO's control center to maintain system reliability.[44]

In terms of distribution, New York State's IOUs, which are regulated by the NY Public Service Commission ("PSC"), are responsible for: (i) distributing electricity throughout the state; (ii) operating and maintaining their respective electric service distribution systems; (iii) responding to customer requests for service and maintenance; and (iii) serving as the electric service billing agent.[45] The only jurisdiction where electricity distribution does not fall under the responsibility of an IOU is in Long Island, where the Long Island Power Authority operates and maintains the electric distribution system through PSEG Long Island.[46]

There are some similarities between the New York and Hawaii markets. Both markets are operated in a single state. Both markets have increasing renewables in their energy mixes because of ambitious renewables goals, such as the RPS in Hawaii and the Clean Energy Standard ("CES")

---

[39] EIA. *New York State Profile and Energy Estimates*. Web. <https://www.eia.gov/state/analysis.php?sid=NY>. Access Date: April 20, 2018.

[40] NYISO. *2017 Load & Capacity Data Report ("Gold Book")*. April 2017.

[41] "Transmission Overview." *NYPA.* <https://www.nypa.gov/power/transmission/transmission-overview> Access Date: April 23, 2018.

[42] "Local Transmission Owner Planning Process." *NYISO.* <http://www.nyiso.com/public/markets_operations/services/planning/process/ltpp/index.jsp> Access Date: April 23, 2018.

[43] New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

[44] NYISO. *Transmission and Dispatching Operations Manual 2016.* December 1, 2016.

[45] New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

[46] "About Us." *PSEG Long Island.* <https://www.psegliny.com/page.cfm/AboutUs> Access Date: April 23, 2018.

in New York. According to the CES, 50% of New York's electricity should be generated from carbon-free renewable energy sources such as solar, wind, hydropower, and biomass by 2030 ("50 by 30 goal").[47] Both states support further growth of distributed energy resources ("DER"). Utilities' new role as "Distribution System Platform Providers" was designed to coordinate and facilitate deployment of various DERs on the grid.

However, the New York market and the Hawaii market are different in terms of market size and market structure. New York's electricity market is much larger than Hawaii's, as Hawaii's annual sales were only 6% of the annual sales in New York in 2016. Also, as mentioned above, New York's market is already a robust competitive wholesale and retail market, while the dominant utilities in Hawaii are vertically integrated and responsible for planning and dispatch. Moreover, the New York market is interconnected with numerous neighbors while Hawaii is isolated from the mainland and each island has its electric grid that is not connected with one another. However, we an assessment of the key components of Reforming the Energy Vision ("REV," as discussed below in Section 4.2.2 and 4.2.3) is merited and would still be valuable as part of this process.

4.2.2 Overview of New York's regulatory framework

In 1996, the New York NY PSC, which oversees the electric, gas, water, and telecommunication industries for the state, embarked on a restructuring of New York's electricity industry.[48] In doing so, the NY PSC sought to *"identify regulatory and ratemaking practices that [would] assist in the transition to a more competitive electric industry designed to increase efficiency in the provision of electricity, while maintaining safety, environmental, affordability, and service quality goals."*[49] Since then, the NY PSC has overseen the divestiture by the state's electric utilities of their generating facilities, the establishment of an independent system operator ("NYISO"), and the creation of competitive retail markets, which permit end-user customers to purchase electricity from energy service companies ("ESCOs").[50]

The NYISO was authorized to be established by FERC in 1998 and launched on December 1, 1999.[51] Its principal responsibilities include: ensuring the reliable operation of the bulk electricity grid of New York State, designing and implementing open and competitive wholesale electricity markets, and planning for New York's energy future.[52] Currently, the NYISO runs four markets:

---

47 2015 New York State Energy Plan Frequently Asked Questions. Web. <http://energyplan.ny.gov/-/media/nysenergyplan/2015-faqs.pdf>

48 The Association of the Bar of the City of New York. *Electric Regulation in the State of New York.* February 9, 2007.

49 New York Public Service Commission. *Competitive Opportunities Regarding Electric Service, No. 94-E-0952.* March 6, 1996.

50 The Association of the Bar of the City of New York. *Electric Regulation in the State of New York.* February 9, 2007.

51 FERC. *Electric Power Markets: New York (NYISO).* Web. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 20, 2018.

52 LEI. *LEI Semi-annual Regional Market Update and 10-year Energy and Capacity Price Forecast: New York.* 3rd Quarter 2017.

(i) energy market (both day-ahead and real-time); (ii) capacity market; (iii) ancillary services market (for regulation and reserve services); and (iv)Transmission Congestion Contracts market.[53] Since the NYISO was established in late 1999, the NYISO has taken operational control of the bulk power transmission system and the dispatch of generation in the State of New York.

Over the last 15 years, New York has strived to increase its renewable generation. In June 2002, the New York State Energy Planning Board released its 2002 State Energy Plan, which aimed to improve the State's use of renewable energy from 10% in 2000 to 15% in 2020.[54] In 2009, Governor Paterson announced the "45 by 15" Clean Energy Policy that proposed to reduce electricity end-use in 2015 by 15% below forecasted levels while simultaneously meeting 30% of the State's electricity supply needs through renewable resources.[55] Then, in April 2014, the NY PSC initiated a public proceeding to evaluate regulatory reforms. The objective was to "align electric utility practices and our regulatory paradigm with technological advances in information management and power generation and distribution."[56] In September 2014, New York City committed to 80 x 50, reducing greenhouse gas emissions by at least 80% by 2050.

Furthermore, Governor Andrew M. Cuomo laid out the REV strategy, *"to build a clean, resilient, and affordable energy system for all New Yorkers"* in 2015[57] He also directed the State Department of Public Service to design and enact a new Clean Energy Standard mandating that 50% of all electricity consumed in New York resulting from clean energy resources by 2030.[58] Currently, utilities in New York are transforming to become Distributed System Platform Providers ("DSPP"). Furthermore, under REV, market-based platform earnings and outcome-based earning opportunities will be added to the standard cost of service ratemaking approach.

4.2.3 History of transition and recent development

As described in the scope of work, the distribution-focused regulatory model is similar to the REV model that the electricity sector in New York State is transitioning into. This model targets are increasing the use of distributed energy resources ("DER") and improving customer participation in the electricity sector. Also, it is fundamentally shifting the role of the utility from an entity that develops and maintains transmission and distribution assets (utilities in New York

---

53 Ibid.

54 New York State. *2002 New York State Energy Plan. Executive Summary*. Page S-3.

55 Governor David A. Paterson. *2009 State Energy Plan Volume I*. December 2009. page 6.

56 NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*. Order Instituting Proceeding. Issued and effective April 25, 2015.

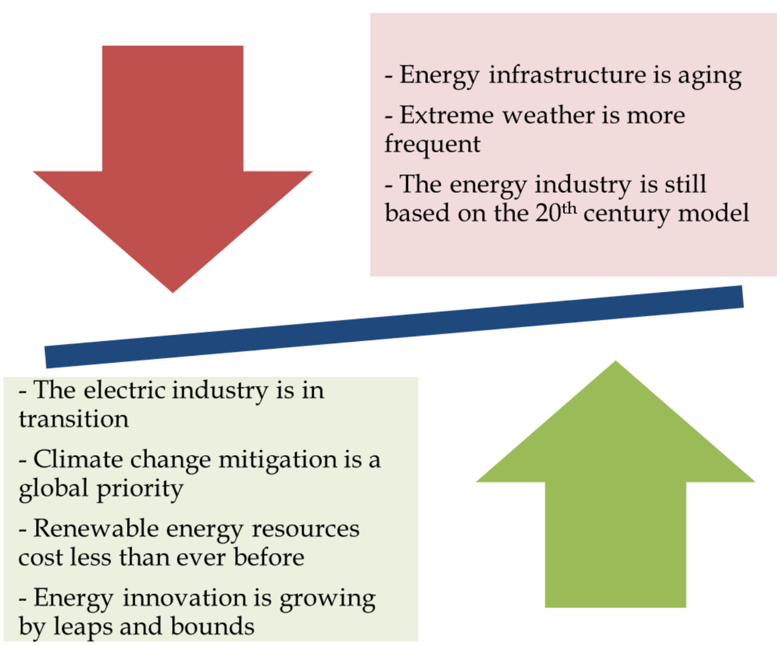
57 Department of Public Service. New York State. *Reforming the Energy Vision*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: April 20, 2018.

58 New York State. *Governor Cuomo Directs Department of Public Service to Begin Process to Enact Clean Energy Standard.* Website. <https://www.governor.ny.gov/news/governor-cuomo-directs-department-public-service-begin-process-enact-clean-energy-standard>

generally are not allowed to own generation assets) to an entity that enables the localized management of electricity supply and demand.

As shown in Figure 7, REV was launched in part to help address concerns about aging energy infrastructure/regulatory model and the need to transition technologies and increase innovation. Similarly, Hawaii is facing the same challenges in its electricity sector. As discussed in Task 1.1.3, almost a third of the oil-fired generation capacity in Hawaii is from plants that are 40 – 49 years old, and more than a quarter of the plants are 50 years or older. Furthermore, as mentioned in its Order, the Hawaii PUC acknowledged that "*Hawaii's electric power industry is in the midst of a significant transition from predominantly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems.*"[59] The Hawaii PUC also noted that "*Hawaii's regulatory framework must also continue to evolve to enable the State's electric utilities to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and result in affordable rates.*"[60]

Figure 7. Reasons for regulatory reforms in New York



Source: New York State. About REV.

In April 2014, the NY PSC initiated a public proceeding to examine and evaluate regulatory reforms including two tracks:

---

[59] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation*. (Order No. 35411). (Docket No. 2018-0088). page 1.

[60] Ibid, page 3.

- Track One focuses on the DSPP issues; and,
- Track Two focuses on regulatory changes and ratemaking issues.[61]

According to the NY PSC, utilities should take on the new role of DSPP and be responsible for "*planning and designing its respective distribution system in a manner that integrates DER as a primary means of meeting system needs.*"[62] This will require the DSPP to "*use localized, automated systems to balance production and load in real time while integrating a variety of DER, such as intermittent generation resources and energy storage technologies*."[63] Moreover, DSPPs are required to "*take steps to ensure that distribution systems continue to be modernized through the use of 'smart grid' technologies*" and "*coordinate its planning functions with the implementation by customers of customer-sited DER*."[64] Also, the Track One Order requires each utility, as a DSPP, to file a Distributed System Implementation Plan ("DSIP").[65] On June 30, 2017, New York's investor-owned utilities filed their first DSIPs, which include both a self-assessment of abilities to integrate distributed resources and a five-year roadmap. This will be updated every two years.[66]

It should be noted that the PSC received more than a thousand comments on its initial REV proposal and it was a lengthy process (April 2014 to February 2015) to determine the definition of DSPPs and their responsibilities.[67] Regarding implementation, the PSC initially proposed a phased approach to implementation, distinguishing among "near-term no-regrets" actions, traditional steps, and the planning and design of mature REV markets.[68] Stakeholders "overwhelmingly" supported a phased approach, but expressed their concerns including focus, timing, and resources required of the implementation process.[69]

---

[61] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014). Page 6.

[62] Ibid, page 12.

[63] Ibid, page 13.

[64] Ibid, page 14 - 15.

[65] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order). Page 32 and 129 - 130.

[66] Ibid, page 2.

[67] The PSC's initial proposal was released in April 2014 and the framework/implementation plan was adopted in February 2015.

[68] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued and effective February 26, 2015). Page 125.

[69] Ibid, page 126.

The PSC emphasized that "the pace of the REV initiatives reflects the challenges and circumstances"[70] that they face. Also, the PSC admitted that "a convergence of problems is clearly foreseeable, and the solution will be years in the making," but it is their responsibility to start right away.[71] Moreover, their approach is to "view the issues as comprehensive as possible, then to sequence the implementation in a manner that allows further progress to be informed by lessons learned."[72]

However, the NY PSC noted that possible effects the utility's involvement could be addressed not only through market rules but also through incentives to ratemaking that provides opportunities to utilities to use DER without regard to ownership.[73] The corresponding ratemaking and revenue model, as described in the Track Two Order, is based on the conventional COS ratemaking approach adding a combination of market-based platform earnings and outcome-based earning opportunities.[74] Utilities will have four ways of achieving earnings, including 1) traditional cost-of-service earnings, 2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit, 3) earnings from market-facing platform activities; and 4) transitional outcome-based performance measures.[75] The Track Two Order initiated the following actions:[76]

1. Earning opportunities:

    - platform service revenues: revenues associated with the operation and facilitation of distribution-level markets;

    - earning adjustment mechanisms: incentives for system efficiency, energy efficiency, customer engagement, interconnection, affordability, etc.; and,

    - greenhouse gas reductions.

2. Competitive market-based earnings: unregulated utility subsidiaries are authorized to engage in competitive value-added services.

---

[70] Ibid, page 127.

[71] Ibid, page 127.

[72] Ibid, page 128.

[73] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014). Page 28.

[74] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order). Page 2.

[75] Ibid, page 2.

[76] Ibid, page 24 - 27.

3. Data access: utilities may charge a fee for the provision of more refined data or analysis.

4. Clawback reform: utilities are encouraged to displace capital expenditures with third-party DER investment where cost-effective.

5. Standby service: utilities begin a process to modernize the calculation of standby tariffs.

6. Opt-in rate design: utilities can voluntarily participate in advanced rate design including opt-in time of use rates and Smart Home rates.

7. Large customer demand charges: demand charges of commercial and industrial customers will be examined to see if they can be made more time-sensitive.

8. Scorecard metrics: a non-exclusive list of ten scorecard measures are adopted.

9. Mass-market rate design: an analytic approach to examine bill impacts.

As for customer data, the PSC believed that "utilities may not charge for basic levels of customer usage data shared with the customer or with vendors authorized by the customer," as this will "*reduce barriers to consumer use and is consistent with the objective to facilitate market development*."[77] However, for information beyond basic customer data, utilities may assess the charges and utilities may "*continue to charge energy service companies and other vendors for providing monthly customer data for a period in excess of 24 months*."[78]

4.2.4 Implications for Hawaii

For Hawaii, a transition similar to REV could be possible as it aligns with Hawaii's policy goals. However, Hawaii should also be realistic about what such a shift entails in terms of the timing, costs involved in the transformation, and additional or change in roles of the utilities and the PUC. Similarly, ratemaking initiatives need to be adapted to support such a regulatory transition.

The following lessons from New York's REV would be relevant to Hawaii:

- **The process of transitioning to the distribution-focused regulation model would be lengthy and complex.** As mentioned above, it will take years for a jurisdiction to transition to this relatively new model. Hawaii has similar active stakeholders' involvement in critical regulatory debates as New York, so a similarly long and complicated stakeholder process is likely if the PUC proposes to adopt a similar distribution-focused regulation model.

- **If the utilities take the role of DSPP, they should be restricted from owning DERs.** As discussed in REV's Track One Order, "ownership of generation by an affiliate of a utility

[77] Ibid, page 140.

[78] Ibid, page 140.

would unacceptably exacerbate the potential for vertical market power."[79] The NY PSC emphasized that this rationale also applies to "utility ownership of generation at the distribution level, where utilities are also operating distribution systems and retail-level markets for DER products.[80] This challenge exists in Hawaii as well. Currently, utilities own and manage the generation, transmission, and distribution, which results in vertical market power. If utilities take the role of a DSPP and they also continue to own DERs, it would result in even greater vertical market power and create more barriers for competitors to enter the market. Admittedly, this requirement is likely to be contentious and raise the thorny issue of what to do about existing assets owned by HECO Companies and thereby create stranded assets.

- **New ratemaking incentives should be created to attract utilities to optimize the use of DER without regard to ownership.** The utilities need to be paid for serving as DSPP. As discussed earlier, there are additional incentives provided to the NY utilities to perform this role.

4.3 Performance-based regulation model: United Kingdom

4.3.1 Overview of the UK market

The UK[81] electricity market is a mature, competitive market. It was among the first movers in power sector restructuring, and its market reform has generally been considered a success. Except for some old nuclear reactors, the entire sector is privately owned and fully unbundled, with privatization and unbundling beginning in the early 1990s. The current market design is structured around a bilateral market with a centralized balancing market. The retail electricity market is also fully liberalized, and consolidation between generators and retailers have created several large energy companies in the country. There are 149 licensed generators in the UK, led by Électricité de France ("EDF"), RWE Npower, Centrica, Drax, Scottish and Southern Energy ("SSE"), Uniper, InterGen, and ScottishPower.[82]

[79] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order). Page 27.

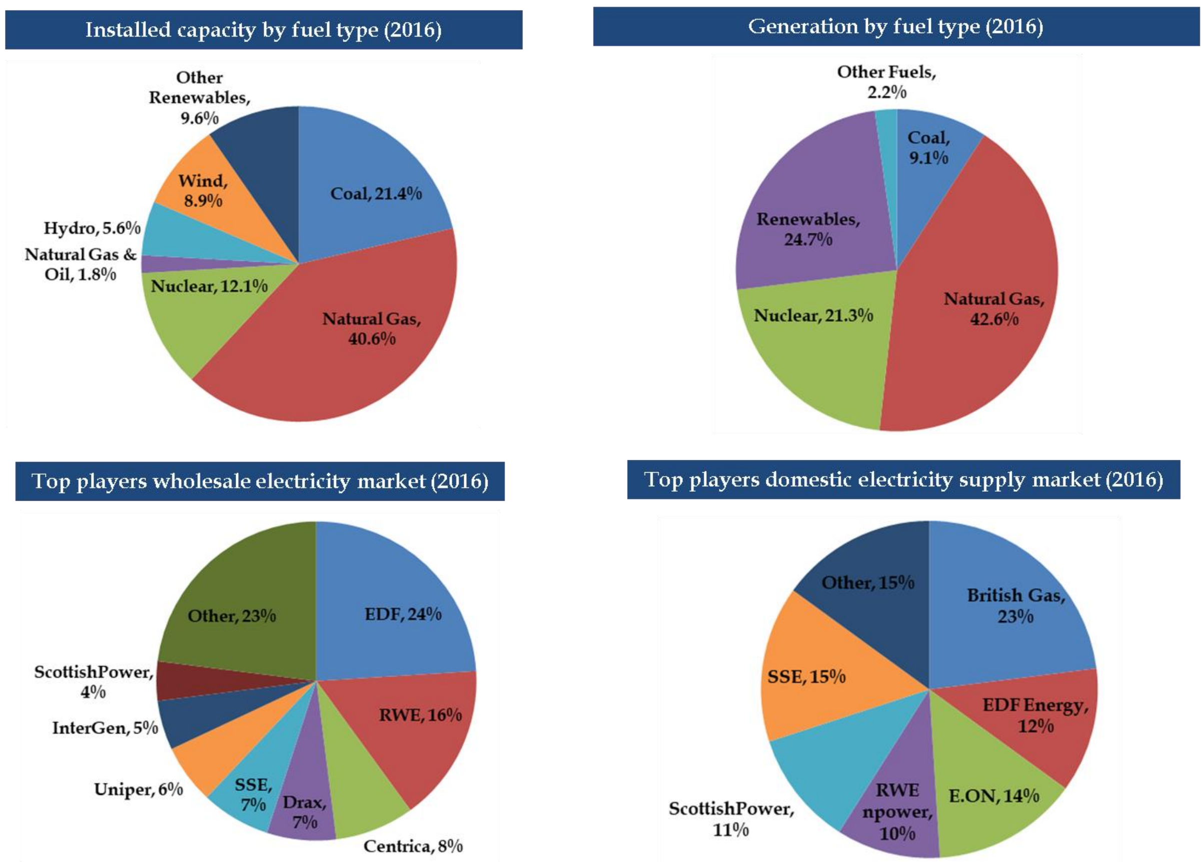
[80] Ibid, page 27.

[81] In this report, we refer to the electricity market in the UK, excluding Northern Ireland, which runs on a separate network.

[82] Ofgem. *State of the Market Report.* October 31, 2017. P. 46.

Figure 8. UK electricity market snapshot

Key facts	
Population (2016)	65.6 million
GDP growth (2012-2016, annual average)	2.2%
Installed capacity (2016)	78.3 GW
Peak demand (2016)	52.9 GW
Load growth (2012-2016)	-1.7%
Generation (2016)	336 TWh
No. of electric distribution companies	14
No. of electric transmission companies	3



Sources: "United Kingdom." *The World Bank.* <https://data.worldbank.org/country/united-kingdom>; UK Department for Business, Energy & Industrial Strategy. *Digest of United Kingdom Energy Statistics (DUKES) 5.1, 5.5, 5.7, 5.10.* July 27, 2017; Ofgem. *State of the Market Report.* October 31, 2017.

The UK has a wholesale electricity market where generators sell electricity to suppliers through bilateral contracts, over-the-counter trades, and spot markets. It has been open to competition since 1990 with the creation of the Electricity Pool ("Pool"). The Pool was replaced with the New

Electricity Trading Arrangements ("NETA") in England and Wales and subsequently by the British Electricity Trading Transmission Arrangements ("BETTA") in April 2005, which extended the previous arrangements to Scotland and thus introduced a single wholesale electricity market for Great Britain.[83] In 2014, the government established the capacity market as part of its Electricity Market Reform policy, which is intended to help secure electricity supplies for the future.[84]

The transmission assets are owned and maintained by three regional monopoly transmission owners ("TOs"), namely: National Grid Electricity Transmission ("NGET") for England and Wales, Scottish Power Transmission Limited ("SPTL") for southern Scotland, and Scottish Hydro-Electric Transmission Limited ("SHETL") for northern Scotland and the Scottish islands groups.[85] These three TOs must ensure that sufficient transmission capacity is available to the UK transmission network. NGET is the sole system operator of the electricity transmission network and has the responsibility of ensuring that electricity supply and demand are balanced and the system remains within safe technical and operating limits. They are regulated by the Office of Gas and Electricity Markets ("Ofgem") through license conditions and price controls.

Currently, there are fourteen (14) licensed distribution network operators ("DNOs")[86] in the UK, and each is responsible for a distribution service area. These DNOs are owned by six different groups.[87] Similar to the TOs, the DNOs are also regulated by the Ofgem through license conditions and price controls. Most DNOs are part of a holding company, which is also involved in the generation and/or supply businesses.

---

[83] "Glossary." *Elexon.* <https://www.elexon.co.uk/glossary/british-electricity-trading-and-transmission-arrangements/>

[84] Ofgem. *Capacity Market Rules*. Website. <https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-market-reform/capacity-market-cm-rules>

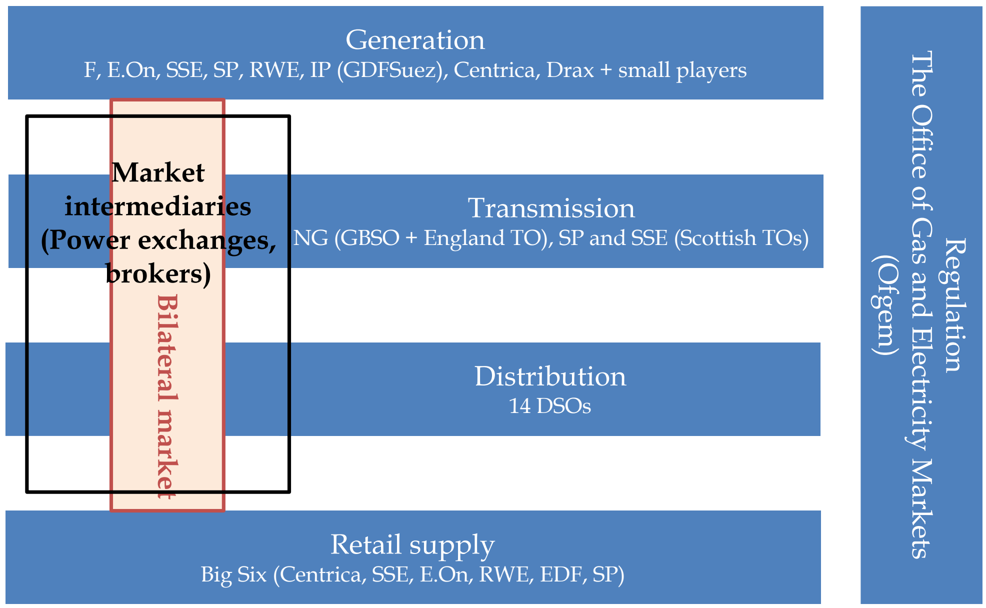
[85] These are the three onshore transmission owners ("TOs"). There are also offshore TOs. Source: "The GB Electricity Transmission Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network>

[86] These DNOs include: Northern Powergrid (Northeast) Limited, Northern Powergrid (Yorkshire) plc, London Power Networks plc, South Eastern Power Networks plc, Eastern Power Networks plc, Electricity North West Ltd, Scottish Hydro Electric Power Distribution plc, Southern Electric Power Distribution plc, SP Distribution Ltd, SP Manweb plc, Western Power Distribution (East Midlands) plc, Western Power Distribution (West Midlands) plc, Western Power Distribution (South West) plc, and Western Power Distribution (South Wales) plc. Source: "The GB Electricity Distribution Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network>

[87] These six (6) groups are composed of: (i) Electricity North West Limited, (ii) Northern Powergrid (owns Northern Powergrid (Northeast) Limited and Northern Powergird (Yorkshire) plc), (iii) SSE (owns Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc), (iv) ScottishPower Energy Networks (owns SP Distribution Ltd and SP Manweb plc), (v) UK Power Networks (owns London Power Networks plc, South Eastern Power Networks plc, and Eastern Power Networks plc), (vi) Western Power Distribution (owns Western Power Distribution (East Midlands, West Midlands, South West, and South Wales) plc. Source: Ibid.

Electricity retail supply is legally separated from distribution. The major electricity suppliers—comprising six large vertically integrated suppliers[88] with a total combined market share of 82%—include British Gas, SSE,[89] E.ON, EDF Energy, Scottish Power, and RWE Npower (also known as the 'Big Six').[90] Competition among suppliers was introduced to improve quality of service to consumers, encourage consumer switching, and create pressure for lower and more innovative tariffs.

Figure 9. Relationship of the different sectors in the UK electricity market



Source: National Grid

There are some similarities between the UK and Hawaii markets. Both markets have increasing renewables in their energy mixes because of the introduction of environmental policies, such as the RPS in Hawaii and the renewable obligation ("RO"), which came into effect in 2002 in the UK.[91] The RO encourages investment of large-scale renewable electricity generating stations by setting an obligation on licensed electricity suppliers to source a portion of their supply from

[88] Integrated generation and supply businesses.

[89] Formed in 1998 with the merger of Scottish Hydro and Southern Electric.

[90] Ofgem. *State of the Market Report.* October 31, 2017. P. 20-21.

[91] "About the RO." *Ofgem.* <https://www.ofgem.gov.uk/environmental-programmes/ro/about-ro>

renewable sources.[92] Also, like Hawaii, over recent years the UK has witnessed *"a dramatic growth in the number of distributed generators seeking to connect to the distribution network*."[93]

Nevertheless, there are also stark differences between the two. For one, the UK has a larger electricity market than Hawaii. Hawaii's annual sales in 2016 represented 3% of the UK's yearly sales. Likewise, Hawaii's peak demand[94] represented 3% of the UK's peak demand[95] in 2016. Also, the UK has fully competitive markets in the generation and supply sectors, while Hawaii has a vertically integrated utility that dominates the generation sector in each county. Finally, the UK is a mature market in terms of restructuring, unbundling privatization, and market reforms, after having gone through several iterations of the market design. Hawaii, on the other hand, has undergone limited restructuring.

4.3.2 Overview of UK regulatory framework

The energy sector in the UK is governed by the Department of Energy and Climate Change ("DECC"), a ministerial department. The Gas and Electricity Markets Authority ("GEMA"), which operates through Ofgem, regulates the electricity and gas markets. This section provides a summary of the regulatory bodies in the UK energy market and their responsibilities.

DECC sets the electricity policies in the UK. It is responsible for ensuring that the market has a secure supply of energy by promoting policies that encourage investments in the UK's energy infrastructure. It also provides the delivery of low-carbon energy at the least cost to consumers.

Ofgem is the executive arm and the independent economic, regulatory body of the gas and electricity markets in the UK.[96] It is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derived its regulatory powers from the Gas Act 1986, the Electricity Act 1989, and the Utilities Act 2000.[97] Ofgem's functions include administering a price control regime for network operators, monitoring the quality of services by setting guaranteed standards of performance and deciding upon proposed industry code changes. Ofgem operates under the guidance and governance of GEMA, which makes all major

[92] Ofgem. *Renewables Obligation: Annual Report 2016-17.* March 21, 2018.

[93] Ofgem. *Distributed generation.* Website. <https://www.ofgem.gov.uk/electricity/distribution-networks/connections-and-competition/distributed-generation>. Access Date: June 28, 2018.

[94] 1,784 MW in 2016, source: DBEDT. *2016 State of Hawaii Data Book. Section 17 - Energy and Science*. 17.10 Electric Utilities, by island. 2016.

[95] 52,909 MW in 2016, source: UK Department for Business, Energy and Industrial Strategy. *Plant loads, demand and efficiency*. 2016.

[96] The Utility Regulator regulates the electricity, gas, and water sectors in Northern Ireland.

[97] Australia Competition and Consumer Commission. *Regulatory Practices in Other Countries Benchmarking opex and capex in energy networks.* May 2012.

decisions and sets policy priorities for Ofgem.[98] Ofgem also has the powers to investigate suspected anti-competitive behavior.

4.3.3 History of transition and recent developments

The UK uses a PBR regime in setting the electricity price[99] for the natural monopoly networks. Introduced in the early 1990s, the PBR used by the UK was in the form of an RPI-X cap mechanism where the RPI was the inflation in the Retail Price Index, and X was an efficiency factor. This meant that rates were allowed to increase by inflation minus an efficiency factor. Until 2010, the RPI-X values for P_0 and X were predetermined, and revenues were forced to conform to these annual changes.

The RPI-X regime was replaced by the current RIIO[100] model, which builds on its predecessor's success, but better meets investment and innovation challenges by emphasizing incentives to drive the innovation needed to deliver a sustainable energy network.[101] The DPCR5 was replaced by the RIIO-ED1 price control on April 1, 2015 and is set to extend until March 31, 2023. RIIO-ED1 sets the outputs that the 14 DNOs need to deliver for their consumers, as well as the associated revenues they are allowed to collect over the eight-year period.[102]

The UK's PBR has employed a "building blocks" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated utility over the term of the price controls. In particular, revenue requirements are set based on estimates of the likely capital and operating costs and return of and return on an efficient asset base. Actual allowed revenues for each utility vary depending on how well it performs against some incentives. Figure 10 shows the components of revenue requirements under the UK's building blocks approach.

---

98 GEMA consists of non-executive and executive members. It determines the strategies, sets policies, and takes decisions on various matters such as price controls and implementation. Its powers are provided for under the Gas Act 1986, Electricity Act 1989, Utilities Act 2000, Competition Act 1998, and the Enterprise Act 2002.

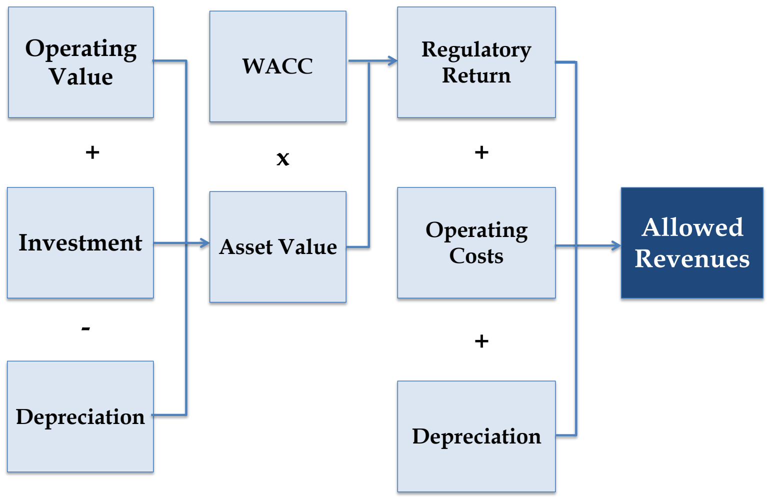
99 Which they call "price control."

100 Revenue = Incentives + Innovation + Outputs

101 "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls>

102 "RIIO-ED1 Network Price Control." *Ofgem.* <https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-ed1-network-price-control>

Figure 10. Components of the allowed revenues



Source: Ofgem ("History of Energy Network Regulation")

In the UK, Ofgem uses the Information Quality Incentive ("IQI")[103, 104] scheme to further encourage TOs and DNOs to reveal their efficient costs and discourage inflated capital expenditure forecasts through a reward and penalty framework.[105] It provides incentives for a TO or DNO to not only propose efficient and prudent costs as part of its regulatory review but also to realize timely investment when needed (rather than to game the system to time investment with PBR terms). The IQI provides incentives by giving additional income to TOs or DNOs whose forecasts are close to Ofgem's assessment. This incentive is realized by providing TOs and DNOs with a higher incentive rate than those distributors with higher capex forecasts, thereby increasing their reward for outperformance.

The IQI, which has become a vital feature of the UK's approach, specifically addresses the information asymmetries problem that regulators have historically been concerned with under cost of service and also, to some degree, under the building blocks approach.

4.3.3.1 Transmission sector

Under the RIIO model, transmission operators are expected to deliver outputs that are set during the transmission price control review (i.e., RIIO-T1, which covers the period from April 1, 2013,

---

[103] Also referred to as the "sliding scale incentive" in previous regulatory periods.

[104] The IQI scheme was intended to mitigate the information asymmetry between Ofgem, the regulator, and the distributors in capex forecasting and provide incentives to distributors to provide the most efficient level of capex for the requirements of the network over the regulatory period. It aims to reduce the risk of under-investment, reduce the opportunity for distributors with high capex allowances to make high returns for underspend and reward distributors with low capex allowances for delivering against this.

[105] The Information Quality Incentive Mechanism is determined by the following formula:

(Allowed Expenditure – Actual Expenditure) * Efficiency Incentive + Additional Income to March 31, 2021).[106] A list of these outputs is shown in Figure 11 below. Several of the incentives are linked to the percentage of allowed revenue.

Ofgem generally considers a TO's performance against its outputs on an annual basis. The productivity factor ("X-factor") in the UK is not the same as the X-factor in North American markets. The X-factor in the UK's RPI-X is not the productivity target, but instead the glide path in rates that allows the regulated utilities to recover reasonable return if – and only if – efficient costs are achieved. This glide path also allows for smoothing of rates for customers.

Figure 11. NGET's outputs and incentive parameters under RIIO-T1

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive ("HSE")	Statutory requirements. No financial incentive A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs
Reliability	Primary output based on Energy Not Supplied ("ENS")	Incentive rate of £16, 000/MWH which is based on an estimate of the value of lost load ("VoLL"). A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues
Availability	Prepare and maintain a Network Access ("NAP")	Reputational incentive. Potential financial incentives if relevant during development and update of NAP
Customer Satisfaction	Develop customer/stakeholder satisfaction survey	Up to +/-1% of allowed revenue
	Effective stakeholder engagement	Up to 0.5% of allowed revenue via a discretionary reward scheme
Connections	To meet existing legal requirements	General enforcement policy
Environmental	SF_6 – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses	Reputational incentive
	Business Carbon Footprint ("BCF") – publish BCF accounts at business level annually over RIIO-T1	Reputational incentive
	Environmental Discretionary Reward Scheme ("EDR") scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentive	Positive reward available if achievement leadership performance across different scorecard activities.
	Visual amenity – to efficiently meet planning requirements for new infrastructure and deliver visual amenity outputs by mitigating impacts of existing infrastructure when it is located in designated areas	Reputational incentive in the context of its performance in the utilization of two mechanisms: (1) Baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent (2) Initial expenditure cap of £500m to reduce the impact of existing infrastructure in designated areas

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

[106] "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/electricity/transmission-networks/network-price-controls>

Ofgem reviews the TOs' capex forecasts to ensure that projected investments are adequate to maintain the operation of the network and to ensure that customers do not carry the costs of unnecessary investment or any operational inefficiency. Prior to the start of the regulatory period, TOs (as well as DNOs) are required to submit business plans that include, among other data, the utilities' forecasts for network replacement and capacity additions for the next five years. For the forecasted network replacement, Ofgem evaluates each utility's forecasts against its asset replacement policies in the past and the expenditure forecasts of other distributors taking into account the age profile of assets on the individual networks.

Financial models are also used by Ofgem and its consultants to evaluate whether the proposed projects are financeable under the regulatory term. According to Ofgem, financeability is evaluated via different financial ratios (like those used by rating agencies to determine the credit rating). If there are concerns, adjustments can be made to ensure that the utility can fund its operations.

Figure 12. Key components of PBR for the TOs

PBR components for UK for the RIIO-T1	
Form	Revenue cap
Approach	Building blocks approach
Term	8 years
Inflation factor (I factor)	UK Retail Price Index
Productivity factor (X factor)	Expected productivity improvements are embedded in the revenue requirements
Capex (K factor)	Embedded into the revenue requirements. Capital additions are included in the Regulatory Asset Value in the year of purchase of the assets. There is no distinction between new capex and opex when added into the RAV
Service Quality Standards (Q factor)	Rewards/penalties for specific performance targets (see table on NGET's outputs and incentive parameters under RIIO-T1)
Off-ramps	Reopeners are available for costs related to delivering EMR measures or for enhancement of physical security
Exogenous factor (Z factor)	Deviations in generation capacity connections from annual baseline profile and deviations in from baseline profile of investment (due to unanticipated demand connections)

Source: Ofgem. ("RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas")

4.3.3.2 Distribution sector

In 2015, Ofgem moved from the Distribution Price Control Review 5 ("DPCR5") approach to the RIIO-ED1 price control, the first electricity distribution price control to reflect the newly implemented RIIO model. RIIO-ED1, which covers the period from April 1, 2015, to March 31, 2023, requires DNOs to deliver on six (6) outputs: reliability and availability, connections, environment, customer service and social obligations, safety, and innovation.[107,108] DNOs are also incentivized to manage their carbon footprints and report on how their actions have contributed to broader environmental objectives. A list of these outputs and incentives is shown in Figure 13 below.

Although the RPI-X framework worked well in the UK, Ofgem acknowledged that this framework was designed under a different context and may not work well in the future. Electricity networks were intended originally to deliver power from large, centrally-located power stations to homes and businesses around the UK. Electricity networks now need to be set up in such a way that electricity can flow to accommodate a higher number of smaller renewable plants that will connect to the networks. An Ofgem document also listed some of the challenges that distributors are likely to face: connecting more home-based micro generators, linking more small-scale renewables and combined heat and power ("CHP") to the low voltage distribution network, adapting to the impacts of climate change, and coping with active demand management.[109]

In the UK, there are several mechanisms in place to ensure that DNOs do not focus on cost-cutting measures at the expense of customer service. Some of the performance standards that are currently in place include: customer interruptions, customer minutes lost through interruptions each year, customer satisfaction, speed of providing quotes, speed of completing work to connect existing or new customers to their networks, percentage of units that are lost in distributing electricity to customers, and efficiency of connection of distributed generation. Distributors are rewarded or penalized if the targets set for these standards are not met. In designing the rewards and penalties for the target results, Ofgem uses the return on regulatory equity ("RORE")[110] as a measure of the DNOs' performance.[111] For the current period, Ofgem has also placed caps on the DNOs' exposure to each incentive, but it did not impose a cap on the extent to which DNOs can outperform the targets by being more efficient.[112]

---

[107] "Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-ed1-network-price-control>

[108] Ofgem. *RIIO-ED1 Annual Report: 2016-17.* December 19, 2017.

[109] Ofgem, *Regulating Networks for the Future RPI-X 20 Emerging Thinking,* (London: 2010), p. 36 and Ofgem, *RIIO – A New Way to Regulate Energy Networks*, (London: Ofgem, 2010), p. 1.

[110] The RORE is also used to determine the cost of capital.

[111] For instance (and as discussed in the *Ofgem Electricity Price Control Review Final Proposal*),[111] if all companies match the customer minutes lost performance currently achieved by the most efficient distributor, and were able to achieve their own best customer interruptions performance from the previous regulatory period in every year of the current regulatory period and earn the cap on losses and customer satisfaction, then they would be able to earn around another 110 to 220 basis points over the period. Given the WACC for the current regulatory period is at 4.7%, this would mean that shareholder returns at over 10% for all DNOs.

[112] *Ibid.* p. 56.

contact:
Tianying Lan/Shrutika Sainani
(617) 933-7229
tianying@londoneconomics.com

There are also re-openers or "logging up mechanisms" for distributors during special circumstances to ensure that both the distributors and consumers are protected from differences between the actual and assumptions underpinning the price control.[113] The PBR also has flow-through mechanisms to ensure that costs beyond the DNOs' control are covered and passed through to customers. There are also incentives to invest in technological improvements.

Figure 13. DNO's outputs and incentive parameters under RIIO-ED1

Category	Output	Incentive
Reliability and availability	Improvements in network reliability measured through the number of customer interruptions and the duration of these interruptions	Interruptions Incentive Scheme ("IIS") incentivizes DNOs to reduce the frequency and duration of interruptions experienced by customers
Connections	Sets targets related to time required to quote connections to customers and the time taken to actually connect customers	Time to Connect Incentive ("TTC") incentivizes DNOs to connect customers in a timely and efficient manner; Incentive on Connections Engagement ("ICE") incentivizes DNOs to meet the needs of larger connection customers, i.e. unmetered, generation and higher-voltage demand customers
Environment	Includes reducing BCF, SF_6 emissions and oil leakage from fluid-filled cables	Reputational incentives such as the Losses Discretionary Reward ("LDR") scheme
Customer service and social obligations	DNOs are to engage proactively with stakeholders in order to anticipate their needs and to deliver a consumer-focused, socially responsible and sustainable electricity service	Broad Measure of Customer Service ("BMCS"), which is comprised of the Customer Satisfaction Survey, Complaints Metric, and Stakeholder Engagement and Consumer Vulnerability ("SECV")
Safety	DNOs must be compliant with standards set by the Health and Safety Executive ("HSE")	
Innovation	DNOs are to achieve Ofgem's vision of innovation being central to the transition to a low carbon economy	Network Innovation Allowance ("NIA"), which funds smaller scale research, development and demonstration projects; Network Innovation Competition ("NIC"), an annual competition which provides funding to a small number of large-scale innovation projects; Innovation Roll Out Mechanism ("IRM"), which facilitates the roll out of proven innovations

Source: Ofgem. *RIIO-ED1 Annual Report: 2016-17.* December 19, 2017.

4.3.4 Implications for Hawaii

Clearly, the long history of reforms in the UK energy sector points to the crucial role that policy plays in pursuing the market's objectives. Policy reforms have been borne out of deeper market appreciation, more profound dialogue and consensus-building, and a stronger call for low-carbon development. The UK example presents a credible case for the merits of PBR. However, this requires an independent and transparent regulatory environment and the strong commitment and co-operation of system operators, utilities, and consumers. Hawaii can learn from the UK's experience in effectively implementing the PBR approach. Below are useful insights and lessons learned, from the UK experience:

- **Provide clear objectives for electricity reforms or any other regulatory changes upfront**. The UK was transparent with its goals in its 1990 restructuring. Providing a clear path

[113] Ofgem. *Electricity Distribution Price Control Review Final Proposals – Cost Assessment.* London: Ofgem, 2009, p. 6.

allows industry players to prepare for the changes in the marketplace. Also, these reforms and transitions require a gradual process which will take a few years.

- **Establish performance standards and quality of service**. The UK's use of performance targets combined with a penalty and reward incentive system has improved the quality of service of DNOs. HI currently has some performance incentive mechanisms where rewards and sanctions are imposed if targets are not achieved.

- **Adapt to the changing environment.** The framework for the electricity transmission and distribution price controls has changed significantly when compared with the regime that was put in place at privatization. Ofgem routinely makes modifications to the PBR regulations after each regulatory period to adapt to changes in the environment or improve a particular mechanism that did not work as anticipated. However, some would argue that the changes have been too frequent without corresponding benefits.

- **Recognize what works and what does not work**. In the original provision of the price controls implemented at privatization, revenues for distributors were allowed to increase in line with the number of units distributed. However, Ofgem recognized that this arrangement had the unintended effect of incentivizing distributors to increase the volume of units distributed. To address this, changes to the revenue driver mechanism were implemented in the next regulatory period under which the influence of units distributed was reduced to a weight of 50%, with the other 50% linked to customer numbers.

- **Provide incentives to encourage cost efficiency and quality service in its PBR.** Ofgem has put in place incentives for TOs and DNOs, so they can continue to innovate, deliver services efficiently, and provide an appropriate level of network capacity, security, reliability, and quality of service. Some of these incentives include a low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, innovative funding incentive, and the IQI. TOs and DNOs are also able to keep some of the benefits if the business can operate at a lower cost or exceed target levels—of performance standards or customer service—at the same cost.[114] Hawaii's PUC, in Order 35411, stated some of these items namely greater cost control and reduced rate volatility, efficient investment and allocation of resources, fair distribution of risks between utilities and customers, and fulfillment of State policy goals as the targeted results of the PBR design in the State.

4.4 Lighter regulation for co-op: Alaska

As stated in Task 2.1.1, the Project Team evaluated a separate regulatory model for KIUC – one with lighter PUC oversight compared to the status quo. Correspondingly, the Project Team

[114] In fact, the Ofgem reported that for the 2010-2015 period, well performing distributors could earn up to 13% equity returns within the regulatory period.

reviewed Alaska as a case study for this model as Alaska is mostly served by co-ops[115] and it has some similarities with Hawaii as discussed below.

4.4.1 Overview of the Alaska market

Alaska's electricity market is regulated, and the Regulatory Commission of Alaska ("RCA") oversees the state's electric utilities. The electric infrastructure in Alaska differs from that of the other jurisdictions outlined in this report, as well as that of most of the conterminous United States. While Alaska does have an interconnected grid, the Railbelt, which serves the most densely populated area of the state (approximately 75% of the population) from Fairbanks to south Anchorage, the grid is not linked to large, interconnected grids in the Lower 48 states or Canada through transmission and distribution lines.[116] Rather, the network in Alaska is a "*patchwork of unconnected grids,*" attributable to Alaska's overall low population density as well as distances between population centers.[117] This is somewhat similar to Hawaii, as each of Hawaii's islands has its own electrical grid, not connected to any other island. Furthermore, as depicted in Figure 14, the installed capacity in Alaska totaled 2,742 MW in 2016, similar to that of Hawaii.[118] The existing generation portfolio is largely dominated by natural gas, which accounted for approximately 48% of utility-scale generation in 2016. This is followed by 26% from conventional hydro, 13% from petroleum liquids, and 9% from coal, and 7% from other renewables, including wind and biomass.[119]cooperatives

Alaska's electricity utilities include investor-owned utilities ("IOUs"), municipally-owned/publicly-owned utilities, and member-owned electric cooperatives. Over 90% of Alaska's electricity supply is provided by vertically-integrated utilities. Collectively, Anchorage Municipal Light & Power, Chugach Electric Association (cooperative), Matanuska Electric Association (cooperative), Golden Valley Electric Association (cooperative) own 1,610 MW or approximately half of the state's total installed capacity. The four utilities also provide generation, transmission, and distribution electricity services in Alaska (Figure 15).

115 More than 74% of retail customers are served by co-ops in Alaska. (Source: S&P Global Market Intelligence Database.)

116 "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

117 Rábago, K.R., Feiler, T., and Damron, F. *Report to: The Alaska Public Utilities Commission and the Alaska State Legislature – Study of Electric Utility Restructuring in Alaska.* CHM2HILL and Econergy International Corporation.

118 "State Electricity Profiles – Alaska Electricity Profile 2016." *US Energy Information Administration.* <https://www.eia.gov/electricity/state/alaska/index.php> Access Date: July 4, 2018.

119 U.S. Energy Information Administration. *Electric Power Annual 2016.* Tables 3.7-3.22. <https://www.eia.gov/electricity/annual/pdf/epa.pdf>

Moreover, two of the five largest plants by capacity (i.e., 300 MW and 170 MW) are owned by Chugach Electric Association.[120] Of the five largest plants, four are natural gas-fired, with the fifth being petroleum-fired plant.

Furthermore, Alaska has limited electric transmission infrastructure. There are approximately 2,045 miles of transmission lines with the majority being less than 230 kV. Major transmission owners include Anchorage Municipal Light & Power, Golden Valley Electric Association, Copper Valley Electric Association, and Matanuska Electric Association. Together, the four vertically-integrated utilities serve approximately 217,000 customers or over 30% of Alaska's population.

There are some similarities between the Alaska and Hawaii markets. First, both states have dispersed grids that are not interconnected with that of neighboring markets due to the states' remote location. With regards to the use of petroleum liquids, a majority of Alaska's rural communities do not have access to the Railbelt[121] and thus, rely on consumer-owned electric cooperatives, many of whom produce some or all of their electricity from diesel.[122] This places Alaska second to Hawaii in terms of per capita generation of electric power from petroleum liquids in the US.[123,124]As such, the Hawaii and Alaska electricity markets rank as the nation's top two markets in terms of electricity generation per capita from petroleum liquids, with Alaska ranking second after Hawaii.[125] Similar to Hawaii, the dominant players in Alaska are vertically integrated utilities. Lastly, both markets are exempted from the Federal Power Act and do not have electric reliability organizations affiliated with the NERC, and also do not fall under the jurisdiction of the FERC.[126]

---

120 U.S. Energy Information Administration. *Annual Electric Generator Report.* Form EIA-860

121 The Railbelt is an interconnected grid that serves the densely populated areas from Fairbanks to the south of Anchorage. The Railbelt utilities are comprised of six utilities, namely Chugach Electric Association, Anchorage Municipal Light & Power, the City of Seward, Homer Electric Association, Matanuska Electric Association, and Golden Valley Electric Association. (Source: "ISO Update." *Renewable Energy Alaska Project (REAP).* September 29, 2017. Web. August 10, 2018. < https://alaskarenewableenergy.org/index.php/2017/09/29/iso/>

122 "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

123 U.S. Energy Information Administration. *Electric Power Annual 2016.* Tables 3.7-3.22. <https://www.eia.gov/electricity/annual/pdf/epa.pdf>

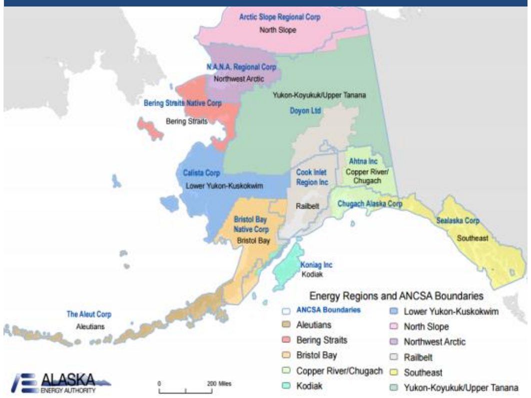
124 "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/analysis.php?sid=AK> Access Date: July 4, 2018.

125 "Alaska State Profile and Energy Estimates." *US Energy Information Administration.* Web. Access date: July 5, 2018. <https://www.eia.gov/state/analysis.php?sid=AK>

126 NERC. *H.R. 6 – 348.* <https://www.nerc.com/AboutNERC/keyplayers/Documents/HR6_Electricity_Title.pdf>

Figure 14. Alaska electricity market snapshot

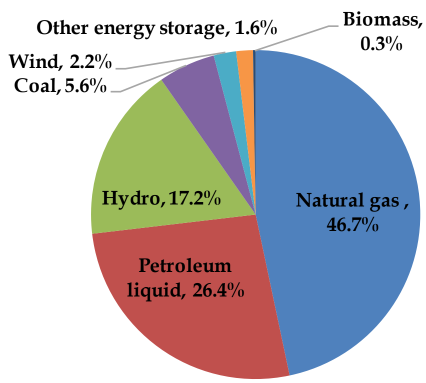
Alaska



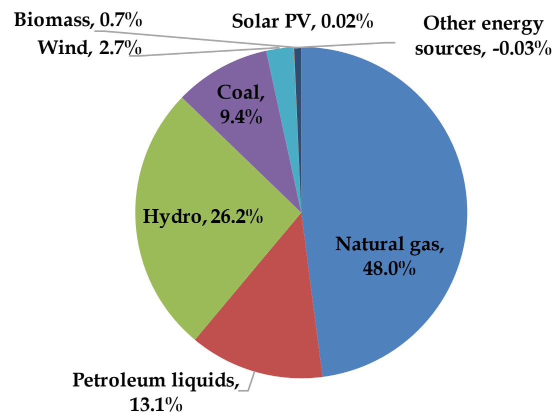
Key facts

Population (2016)	0.7 million
GDP growth (2016)	-4.5%
Installed capacity (2016)	2.7 GW
Peak demand (2016)	1.2 GW*
Load growth (2012-2016)	-0.9%
Generation (2016)	6.34 TWh
No. of utilities	8

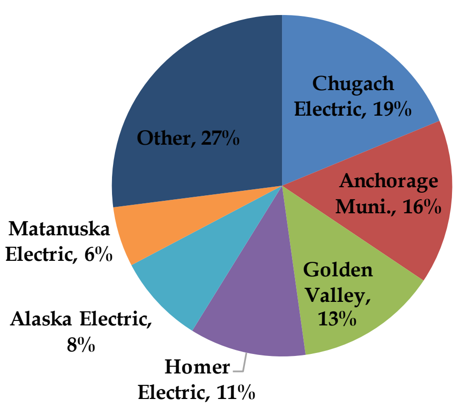
Installed capacity by fuel type (2016)



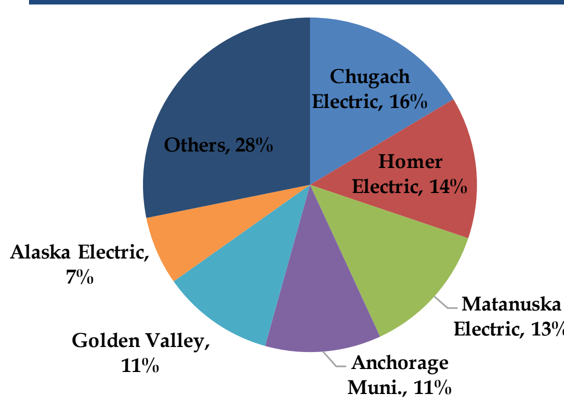
Generation by fuel type (2016)



Top players by installed capacity (2016)



Top players by generation (2016)



Note: *Peak demand listed is non-coincident peak demand. The number of utilities refers to the total number of T&D utilities.

Sources: US Census Bureau. *State Population Totals and Components of Change: 2010-2017.* January 18, 2018; "Regional Data." *US Department of Commerce.* <https://www.bea.gov/iTable/index_regional.cfm>; US Energy Information Administration.

Figure 15. Utilities providing generation, transmission, and distribution electricity services in Alaska

	Anchorage Municipal Light & Power	Golden Valley Electric Association (Co-op)	Chugach Electric Association Inc. (Co-op)	Matanuska Electric Association (Co-op)
Service territories	Anchorage	Fairbanks, Delta Junction, Nenana, Healy and Cantwell	Area extending from Anchorage to the northern Kenai Peninsula, and from Whittier on Prince William Sound to Tyonek on the west side of Cook Inlet	South of Cantwell down to Eagle River and over to the Matanuska Glacier
Miles of transmission lines owned	N/A – 371 circuit miles of distribution lines	N/A; 3,229 miles of power lines (T&D)	434; 2,153 miles of power lines (T&D)	N/A; 4,200 miles of power lines (T&D)
Numbers of customers served	30,751	44,374	83,855	58,000
Customer profile	15% residential, 85% commercial	29% residential, 71% commercial	Mainly residential	67% residential, 33% commercial
Approved rate of return	4.88%	N/A	N/A	N/A
Regulatory framework used to determine transmission rate	Cost of service	Cost of service	Cost of service	Cost of service
Major ongoing infrastructure projects	N/A	N/A	Full Advanced Metering Infrastructure (AMI) meter deployment by Spring 2017	Wasilla Transmission 115 kV Line

Source: Chugach Electric Association Inc. *Chugach 2016 Annual Report;* Golden Valley Electric Association. *At a Glance.* 2016; Matanuska Electric Association. *2015 MEA Annual Report.*

Nonetheless, unlike Hawaii where most of the customers are served by an IOU (i.e., HECO Companies, except the County of Kauai), over 74% of retail customers in Alaska are served by co-ops. Moreover, the two markets differ significantly with regards to renewable goals. Unlike Hawaii, Alaska has no formal policy targets for emissions reduction or renewables expansion. More specifically, Alaska has no established RPS or other forms of renewables target policy, as well as no established Greenhouse Gas ("GHG") reduction policy objectives.

4.4.2 Overview of the regulatory framework in Alaska

Like Hawaii, Alaska is outside of FERC's jurisdiction. As mentioned in Section 4.4.1, the RCA oversees the operations of the electric utilities in Alaska. As per Alaska Statute ("AS") 42.05.141, the responsibilities of the RCA include, but are not limited to, the following:[127]

- regulate public utilities that conduct utility business in the state;

[127] AS 42.05.141. *General Powers and Duties of the Commission.* Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/statutes/title42/chapter05/section141.htm>

- investigate matters concerning rates, regulations, practices, and services, for instance, of public utilities and hold hearings, as necessary;
- establish or govern rates, regulations, methods, and services, for example, such that they are fair and reasonable;
- regulate the service and safety of operations of public utilities;
- require public utilities to file reports; and
- perform duties as per AS 42.45.100 – 42.45.190.

This is similar to the responsibilities of the Commission in Hawaii, which oversees the operations of electric utilities in the State. Like the RCA, the PUC partakes in activities such as rate regulation, monitoring availability, service quality, and reliability.

4.4.2.1 Regulated cooperatives

For cooperatives formed under AS 10.25 that are regulated by the RCA, cooperative utilities are subject to simplified rate filing ("SRF") procedures. SRF allows both the cooperatives and the RCA to avoid the costs and time associated with traditional general rate cases.[128] Under Article 6 of the Alaska Admin Code ("AAC"), *Simplified Rate Filing Procedures for Electric Cooperatives*, a cooperative may adjust its rates not more than four times a year (i.e., on a quarterly basis). Under the SRF procedure, the board of directors holds a major responsibility in rate adjustments rather than the RCA; that being said, the cooperative must first submit filings to the RCA before implementing any rate changes.[129] As per AAC 48.710(b), a cooperative must file on a quarterly or semi-annual basis (whichever period is opted for) with the RCA information including, but not limited to: RCA Form 201[130]; a schedule and explanation of amortized expenses, pro forma and normalizing adjustments, and of each line on RCA Form 201 which has increased or decreased over 10% from the previous 12-month period"; "*calculation of the cooperative's Times Interested Earned Ratio ("TIER") [as per] 3 AAC 48.750*"; "*the ratio of residential class kilowatt-hour sales to total kilowatt-hour sales for the current 12-month period and the ratio that existed when the cooperative last filed a [COS] study*"; if appropriate, "*the ratio of retail kilowatt-hour sales as a percentage*

[128] "Simplified Rate Filing." *Chugach.* Web. July 5, 2017. <https://www.chugachelectric.com/about-us/regulatory-affairs/simplified-rate-filing>

[129] Ibid.

[130] RCA Form 201 is a modified version of the Rural Electrification Administration ("REA") Form 7, or the Rural Utilities Service ("RUS") Form 7 (the RUS absorbed REA and its responsibilities in 1994). While a version of the RCA Form 201 is not available, the RUS Form 7 is a Financial and Statistical Report that includes, but is not limited to, the following: statement of operations, data on transmission and distribution plant, balance sheet, notes to financial statement, changes in utility plant, materials and supplies, service interruptions, employee hours and payroll statistics, patronage capital, due from consumers for electric service, kWh purchased and total cost, long-term leases, annual meeting and board data, long-term debt and debt service requirements, annual summary of power requirements data base, investments, and loan guarantees. (Source: AAC 48.710; United States Department of Agriculture Rural Utilities Service. *Financial and Statistical Report.* Web. July 24, 2018. <http://www.nmprc.state.nm.us/utilities/docs/form7-2006.pdf>)

of total retail and wholesale kilowatt-hour sales, and the ratio that existed when the cooperative filed its last [COS] study"; and a "*copy of the cooperative's annual certified audit, including any adjusting journal entries*".[131]

These filings may result in an increase in rates, a decrease in rates, or in unchanged rates. While the decrease in rates is not limited, the increase is capped. More specifically, cooperatives "*may not exceed a cumulative [20%] increase in any three-year period, or a cumulative [8%] in any 12-month period, excluding purchased power and fuel costs rate adjustments.*"[132]

4.4.2.2 Deregulated cooperatives

In Alaska, cooperatives may be exempt from the regulation of RCA or deregulated. As per AS 42.05.712, *Deregulation Ballot*, an election may be called upon by the board of directors of a cooperative upon a valid petition from members; the petition must not be signed by less than "*the number of [members] equal to [10%] of the first 5,000 [members] and [3%] of the [members] in excess of 5,000.*"[133]

A majority vote with at least 15% of eligible members voting is required for a co-op to be deregulated (i.e., exempt from the regulations of the RCA).[134] Each member of the co-op must receive a notice with the regular bill for service a minimum of 60 days before the date of the election, which must contain information regarding the election on the option of deregulation or regulation from under the RCA and that each member is entitled to vote. The notice also includes any announcements regarding public meetings where members would have the opportunity to discuss the matter; said meetings would not be held more than 30 days before the ballots are mailed. This vote must be submitted within 30 days from receipt of the information and results are certified within the 60 days after the ballots are sent to members.[135]

While cooperatives may be re-regulated (if members vote in favor of regulation), it must be noted that an election may be only held every two years. There have been seven electric co-ops that voted for re-regulation. Most recently, Egegik Light and Power voted to be reregulated in 2002.[136]

---

[131] "Article 6 Simplified Rate Filing Procedures for Electric Cooperatives." *Alaska State Legislature.* Access date: July 4, 2018. <http://www.legis.state.ak.us/basis/folioproxy.asp?url=http://wwwjnu01.legis.state.ak.us/cgi-bin/folioisa.dll/aac/query=[jump!3A!27title3chap48!2C+a!2E+6!27]/doc/{@10154}?next>

[132] 3 AAC 48.770. *Limitations on use of simplified procedure.*

[133] AS 42.05.712. Deregulation Ballot. Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section712.htm>

[134] Ibid.

[135] Ibid.

[136] "Deregulation/Reregulation Elections." *Regulatory Commission of Alaska.* Web. Access date: July 6, 2018. <http://rca.alaska.gov/RCAWeb/RCALibrary/DeregulationElections.aspx>

Once deregulated, cooperatives are no longer regulated by the RCA except AS 42.05.221 to AS 42.05.281.[137] Instead, co-ops are governed by the board of directors. Conversely, in the case of KIUC in Hawaii, all rates, schedules, rules and practices made or charged by public utilities are required to be filed with the PUC.[138]

AS 42.05.712, *Deregulation Ballot* became effective on August 14, 1980, which was initially in the AS. Information about the history and transition is not publicly available, but a detailed discussion on sample cooperatives that moved to deregulation will be discussed in Section 0.

4.4.3 Implications for Hawaii

Several lessons from Alaska's electricity market, particularly about cooperatives, can be considered for Hawaii. More specifically, the PUC could consider lighter regulation of cooperatives as done by the RCA in Alaska, either via means of voluntary deregulation and/or by the introduction of a simplified and expedited ratemaking process for cooperatives. Below are key insights from Alaska's experience that could be considered:

- **Deregulation does not need to be an "either-or" option; it can take place in different forms.** There are many options for KIUC, ranging from "simplified ratemaking/ investigation process" to complete deregulation. This means that some of the areas that are currently regulated by the PUC could be relinquished. These can include rate governance, ratemaking, and/or filing annual reports. Whether "lighter regulation" or "complete deregulation" would work depends on various factors, including but not limited to, political will, economic benefits, opinions from the community, etc. This would need to be separately considered and analyzed before Hawaii could make any serious decisions about opting for a lighter regulation for co-ops.

- **Should the Hawaii Legislature decide to introduce optional deregulation for cooperatives (or smaller utilities), it should do so with caution.** Prior to offering KIUC lighter regulation, the Legislature and PUC must ensure that appropriate safeguarding mechanisms are in place to protect customers of the electric cooperative. Moreover, as mentioned in Section 4.4.2.2, for an electric cooperative to be deregulated under the RCA in Alaska, a majority vote with a minimum of 15% eligible members voting most occur.[139] To ensure the representativeness of the decisions, the Legislature should set up appropriate rules and percentages for qualified voting. The option of "re-regulation" via voting is another way to protect the customers' interests. Also, other rules might need to

---

[137] AS 42.05.221 *Certificates Required;* AS 42.05.231 *Application;* AS 42.05.241 *Conditions of Issuance*; AS 42.05.251 *Use of Streets in Municipalities*; AS 42.05.254 *Public Utility Regulatory Cost Charge*; AS 42.05.261 *Discontinuance, Suspension, or Abandonment of Certificated Service*; AS 42.05.271 *Modification, Suspension, or Revocation of Certificates*; and AS 42.05.281 *Transfer of Certificate.* (Source: "Chapter 5. Alaska Public Utilities Regulatory Act." *Alaska Statutes.* Web. Access date: July 5, 2018. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05.htm>

[138] HRS § 269-16(a).

[139] Ibid.

be set up to protect customers of partial-deregulated or deregulated cooperatives. For instance, in Colorado (another case that will be analyzed in Section 0), the PUC may resolve complaints from individual customers of deregulated electric cooperatives for certain issues such as discrimination or preferential treatment of a group of customers.[140]

- **KIUC may consider proposing simplified regulatory processes to the Hawaii PUC if legal changes are challenging and time-consuming.** To minimize costs and time associated with lengthy regulatory procedures, KIUC may propose simplified regulatory processes on specific topics to the Hawaii PUC. Like in Alaska, cooperatives use simplified rate filing, enabling them to make reasonable adjustments to demand and energy rates without filing a formal rate case to the Commission.[141]

[140] Colorado PUC. *Deregulated Electric Cooperatives in Colorado*.

[141] "Simplified Rate Filing." *Chugach.* Web. July 5, 2017. < https://www.chugachelectric.com/about-us/regulatory-affairs/simplified-rate-filing>

5 Markets that have changed regulatory models in the past 20 years

This section provides an analysis of some of the jurisdictions that have changed regulatory models in the past twenty years. Since New York State, the only jurisdiction that is currently transitioning to the distribution focused regulatory model [142] was already discussed in Section 4.2; the Project Team will not discuss examples for the distribution focused regulatory model. Therefore, the focus of this section is on examples for the ISO model, PBR, and Lighter Regulation in this section.

To identify examples of the ISO model, the Project Team reviewed all the ISOs in North America, including their establishment year and jurisdictions (states or provinces coverage). Other than ERCOT, which was discussed in Section 4.1, the Project Team believes that California ISO ("CAISO"), Ontario's Independent Electricity System Operator ("IESO"), and Alberta Electric System Operator ("AESO") would be good points of comparison for Hawaii because they are markets that represent a single jurisdiction. Furthermore, some of them have similarly ambitious environmental policies.

Figure 16. Summary of selected markets that have changed regulatory models to ISOs, PBR, and lighter regulation for co-ops

Market	Regulatory model	Number of Utilities	Number of customers	Capacity (MW)	Annual sales (MWh)	Average retail rates (cents/kWh)
California	ISO	14	16,029,429	70,960	284,119,456	14.68
Alberta	ISO/ PBR	11	1,750,000	16,423	79,560,000	8.11
Ontario	ISO/ PBR	71	5,106,528	36,070	130,194,307	12.23
Australia	PBR	21	6,755,510	42,862	196,500,000	19.22
The Philippines	PBR	130	18,519,029	21,423	74,153,000	16.03
Malaysia	PBR	3	9,659,221	26,563	124,709,000	8.66
Colorado	Lighter regulation	6	2,643,315	16,078	54,802,037	9.83
Utah	Lighter regulation	1	1,175,934	8,976	30,179,534	8.72

Note: 2016 numbers. Average retail rates are in US dollars. The number of customers refers to the total number of customers (approximate), and the number of utilities refers to the total number of T&D utilities.
Source: S&P Global. IESO. AESO. Natural Resources Canada.

As for jurisdictions that have changed to PBR models, the Project Team included in the list Australia, the Philippines, and Malaysia. The Philippines and Malaysia were included in the list because these markets have some resemblances to Hawaii, namely being an archipelago and Australia was included in the list because, similar to Hawaii, it is an isolated market. It is worth

[142] We acknowledged that California is also looking into the distribution-focused initiatives. The California PUC published a "DER Action Plan" in November 2016. Its scope includes 1) rates and tariffs, 2) distribution grid infrastructure, planning, interconnection and procurement, and 3) wholesale DER market integration and interconnection. However, California's approach focuses on specific DER integration assessments and optimization of utility operations and planning, while New York called for an overhaul of the utility business model. Source: ScottMadden. *California and New York DER Demonstration Projects*. May 2017.

noting that IESO (Ontario) and AESO (Alberta) has transitioned its ratemaking method to PBR as well in the past several years.

Moreover, Colorado and Utah were selected as markets that have lighter regulation for co-ops but use a different approach from Alaska. Figure 16 summarizes basic information of each market under ISO model, PBR model, and lighter regulation for co-ops.

5.1 Markets that have established ISOs

As mentioned in Task 2.1.1, in the US and Canada, there are nine ISOs found in the late 1990s. Three of them, including ERCOT (1996),[143] PJM (1996),[144] and ISO New England ("ISO-NE") (1997),[145] were established more than 20 years ago. Six of them, including California ISO ("CAISO") (1998),[146] Independent Electricity System Operator ("IESO") (1998),[147] NYISO (1999),[148] Midcontinent ISO ("MISO") (2001),[149] Alberta Electric System Operator ("AESO") (2003),[150] and Southwest Power Pool (("SPP") (2004),[151] were established in the last 20 years (Figure 17). Since MISO and SPP are multi-state ISOs, and NYISO was discussed in Section 4.2, this section will focus on CAISO, IESO, and AESO as they are single-state ISOs with aggressive renewable policies and initiatives especially in CAISO and IESO (like Hawaii).

CAISO, IESO, and AESO are governed by a board of directors and support their operations through charges to market participants. The key tasks of these ISOs are almost the same, including providing open and competitive access to the transmission grids, planning resource adequacy, as well as managing market operations, etc. All of them have energy market and

143 ERCOT. *History*. Website. <http://www.ercot.com/about/profile/history>. Access Date: April 24, 2018.

144 FERC. *PJM market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/pjm.asp>. Access Date: April 24, 2018.

145 FERC. *ISO-NE – History*. Website. <https://www.iso-ne.com/about/what-we-do/history/>. Access Date: April 24, 2018.

146 FERC. *CAISO market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/california.asp>. Access Date: April 24, 2018.

147 IESO. *Corporate-IESO*. Website. <http://www.ieso.ca/en/corporate-ieso>. Access Date: April 24, 2018.

148 FERC. *New York market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 24, 2018.

149 FERC. *Midwest*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/midwest.asp>. Access Date: April 24, 2018.

150 Province of Alberta. *Electric Utilities Act (Statutes of Alberta, 2003, Chapter E-5.1)*. Website. <http://www.qp.alberta.ca/documents/Acts/E05P1.pdf>. Access Date: April 24, 2018.

151 FERC. SPP. Website. <https://www.ferc.gov/market-oversight/mkt-electric/spp.asp>. Access Date: April 24, 2018.

ancillary services, but only AESO has started to set up its capacity market.[152] The capacity in these ISOs ranges from 16,423 MW to 70,960, about 6 to 25 times of the total capacity in the State of Hawaii. Figure 18 summarizes the establishment, governance, and funding information for CAISO, IESO, and AESO.

Figure 17. Review of ISOs' establishment

ISOs	Year of establishment	Single-State ISO?
ERCOT	1996	Y
PJM	1996	N
ISO-NE	1997	N
CAISO	1998	Y
IESO	1998	Y
NYISO	1999	Y
MISO	2001	N
AESO	2003	Y
SPP	2004	N

Note: PJM: Pennsylvania-New Jersey-Maryland; ISO-NE: ISO New England; CAISO: California ISO; IESO: Independent Electricity System Operator (Ontario); NYISO: New York ISO; MISO: Midcontinent ISO; AESO: Alberta Electric System Operator; SPP: Southwest Power Pool

Source: FERC, ERCOT, IESO, AESO, etc.

Furthermore, all the three ISOs were established to encourage competition as part of the market restructuring process. As mentioned in California Assembly Bill 1890, the California ISO was set up to "increase reliability and provide new power producers equal opportunity and ability to deliver their supplies."[153] Similarly, IESO was formed to be in charge of maintaining a balance between electricity supply and demand when the electricity market was restructured and opened up to competition in Ontario.[154] AESO was also formed in the early days of deregulation in Alberta as roles and responsibilities of energy agencies were reviewed and realigned to support the new industry structure.[155]

---

152 California effectively has a bilateral spot market for capacity, where existing generators can sell their capacity on a month-ahead and year-ahead basis to load serving entities that must then show compliance with the California Public Utilities Commission's Resource Adequacy program.

153 EIA. *Provisions of AB 1890*. Website. <https://www.eia.gov/electricity/policies/legislation/california/assemblybill.html>. Access Date: June 28, 2018.

154 Legislative Assembly of Ontario. *Energy Competition Act 1998*.

155 AESO. *Guide to understanding Alberta's electricity market*. Website. <https://www.aeso.ca/aeso/training/guide-to-understanding-albertas-electricity-market/>. June 28, 2018.

Figure 18. Summary of CAISO, IESO, and AESO

Comparison	CAISO	IESO	AESO
Establishment year	1998	1998	2003
Establishment process	• September 1996: Following the federal Energy Policy Act of 1992, CAISO was created as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 • March 1998: CAISO began serving 80% of the State or 30 million people	• 1998: IESO was established by the Electricity Act of Ontario • January 2015: IESO merged with the Ontario Power Authority	• 2003: AESO was created by the Electric Utilities Act of 2003
Report to?	FERC	Ontario Energy Board	Alberta Energy and Utilities Board ("EUB") and the Market Surveillance Administrator under EUB
Governing structure	• CAISO has 5 governors on its Board which are recommended by a 36-member Board Nominee Review Committee, and appointed by the Governor of the State of California and subject to confirmation by the Senate of the State of California • CAISO Board members serve three-year staggered terms, as required by state law	• IESO is governed by an independent board of directors (eleven) including an appointed Chief Executive Officer and a Chair by majority vote • There are two committees of the board: the Audit Committee and the Human Resources and Governance Committee	• AESO is governed by a board of directors (eight members), whose members are appointed by Alberta's Minister of Energy • The Board comprises of four standing committees, including the Audit Committee, Human Resources Committee, Governance and Nominations Committee, and the Power System Committee
Funding	CAISO charges a Grid Management Charge ("GMC") to market participants; other revenues including, but not limited to: fees paid for participation in the Western Energy Imbalance Market ("EIM"), generator interconnection studies, and for operation of the California-Oregon Intertie Path	The IESO has two key sources of revenue: (i) system fees, which are based on approved rates for each megawatt of electricity withdrawn from the IESO-controlled grid (including scheduled exports) and embedded generation; (ii) the Smart Metering Charge that is based on a rate approved by the OEB for each installed smart meter in the province	The AESO's four revenue sources are from market participants for transmission, energy market and renewables, and from owners of electric distribution systems and wires service providers for load settlement; there is no government funding for the operations of the AESO
Markets?	Energy market (day-ahead/ real-time), ancillary services, congestion revenue rights	Energy market (real-time), ancillary services	Energy market (day-ahead/ real-time), ancillary services, capacity market (transitioning)

Source: FERC, CAISO, IESO, AESO, etc.

The California, Ontario, and Alberta markets' experiences underline the feasibility of establishing an ISO in a single state/province out of FERC's jurisdiction. However, considering the unique characteristics that Hawaii has, decision-makers should, most of all, have a full grasp of what exactly the market should be, agree on specific goals (both for the short and long terms), establish the appropriate policy environment, design the market based on unmet needs and best practices, involve stakeholders, and allow for gradual transition. The following summarizes the lessons learned from the ISOs from the jurisdictions reviewed:

- **Developing clear objectives and policies**: challenges in the California market between 2000 and 2001 ("California crisis") were headline news across much of the world, entering immediately into regional market reform dialogues. This is a good example of the importance of developing a deep understanding of what the actual needs are and connecting those with the appropriate policy responses. California created an over-complicated regulatory structure, which could have been caused by unclear (or disagreements on) policy goals. The disconnect (combined with the inability to hedge) led to increased uncertainties, higher risk premiums, and roadblocks for implementation of critical decisions. The prolonged design and passage of the initial restructuring bill led to tightness in the system, discouraging a new generation of investments by utilities (eventually triggering the crisis). Delay in permitting and siting for proposed new entrants did not help the process, and this is a problem that continues to plague California even today given its complex regulatory approval process.

- **Some problems cannot be solved by creating more entities**: in trying to put in renewable policies, both Ontario and CA seem to have developed lots of power related state organizations, which sometimes have overlapping responsibilities. While they are trying to resolve problems by creating these, it sometimes generates more bureaucratic hassle.

- **Creating competition in the generation sector**: the Alberta case presents an example where a market, which was previously dominated by a few vertically integrated utilities, moves gradually to welcome greater competition. While the concept applies to Hawaii, minimum efficient size also needs to be a consideration.

- **Changing market designs is always complex:** for instance, Alberta has been transitioning to from an energy market to a new framework that includes any energy market and a capacity market. The stakeholder engagement process was planned to take three years (2017 to 2019), and a capacity market is anticipated to be in place by 2021.[156] Designing a market for Hawaii from scratch would be even more complex and requires more time and efforts.

5.2 Markets that have set up the PBR model

As discussed in Task 2.1.1, PBR regimes exist in multiple jurisdictions throughout the world. Unlike the UK which started moving to PBR in the 1980s, Australia, the Philippines, and Malaysia transitioned to PBR in the past twenty years. However, similar to the UK, these markets have almost the same rationale for moving into PBR, i.e., to promote economic efficiency and protect the interests of electricity consumers. This rationale applies to Hawaii as well. The Hawaii PUC noted that it is interested in PBR mechanisms that result in:

- "greater cost control and reduced rate volatility;

[156] AESO. Capacity Market Transition. Website. <https://www.aeso.ca/market/capacity-market-transition/>

- efficient investment and allocation of resources regardless of classification as capital or operating expense;
- fair distribution of risks between utilities and customers; and,
- fulfillment of State policy goals."[157]

Several markets have been implementing the PBR for quite some time now. This is the case for Australia, the Philippines, and Malaysia, which is shown on Figure 19. Their PBR is also considered as a "comprehensive" form of PBR where they have the price cap or revenue cap with other components of the PBR such as earnings sharing mechanism, performance standards with rewards (and penalties for some), off-ramps, and exogenous factors.

Figure 19. Summary of PBR regimes in Australia, the Philippines, and Malaysia

	Australia	Philippines	Malaysia (TNB)
Name of regulator	Australian Energy Regulator ("AER") – (Eastern Australia and Economic Regulation Authority (Western Australia)	Energy Regulatory Commission ("ERC")	Suruhanjaya Tenaga ("ST")
No. of dist. and trans. utilities	Distribution: 13 Transmission: 8	Distribution: 20 private Transmission: 1	Distribution: 1 Transmission: 1
Term for incentive regulation	Incentive-based regulation	Performance-based regulation ("PBR")	Incentive-based regulation ("IBR")
Current PBR	Transmission: 3rd Distribution: 2nd (Under the AER)	Transmission: 3rd Distribution: 4th	Transmission and distribution: 1st
Form of PBR	• Distribution – Revenue Cap in Queensland, New South Wales, South Australia and Tasmania; Average Revenue Cap in the ACT; Weighted Average Price Caps in Victoria (will switch to Revenue Cap from January 1, 2016) • Transmission – Revenue Cap with CPI-X • Retail – Retail margins are set by the state regulator	• Transmission – Revenue cap • Distribution – Price cap	• Customer Services - Pure Price Cap • Transmission, System Operator, Single Buyer (Operational) - Revenue Cap • Single Buyer (generation) – actual costs
Year started the PBR	1997 in Victoria	Transmission: 2003 Distribution: 2004	2014
Rationale for doing PBR	To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect: • price, quality, safety, reliability and security of supply of electricity; and • the reliability, safety and security of the national electricity system"	• To promote economic efficiency • To share the benefits of efficiency gains between consumers and utilities • To prevent abuse of monopoly power • To encourage improved service levels • To allow utilities sufficient revenue to operate efficiently and attract investment • To provide transparency and stability	To strengthen: • Economic regulatory framework • Tariff setting mechanism and principles • Incentive mechanisms to promote efficiency • Process of tariff reviews • Creation of regulatory accounts and annual review process
Approach to setting the price	Building blocks	Building blocks	Building blocks

[157] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation*. Order No. 35411. Docket No. 2018-0088. April 18, 2018.

	Australia	Philippines	Malaysia (TNB)
Other components of PBR	• I factor – quarterly CPI index • X factor – specific for each year and utility • Capex – ex ante capex allowances • Q factor – Service target performance incentive scheme • ESM – symmetric ESM • Z factor – applies to specific events such as regulatory or tax change, disaster or terrorist event • Off-ramps – only for transmission utilities; re-opener is available for events significantly alerting the level of capex	• I factor – weighted index of the Philippine CPI • X factor – individually determined for each entity • Capex – ex ante capex allowances • Correction factor – correction for over- or under-recovery of revenues and/or taxes during the previous regulatory period • S factor – rewards or penalties should not exceed 3% of the allowed annual revenue for any regulatory year • Off ramps – increase in I factor • Flow through – cost of purchased power, transmission costs, force majeure, and tax change events	
Performance standards	The Service Target Performance Incentive Scheme has three components applied to TNSPs: • Service Component • Market Impact Component • Network Capability Component – except Directlink and Murraylink The Service Target Performance Incentive Scheme also has four components applied to DNSPs: • 'reliability of supply' component • 'quality of supply' component • 'customer service' component • 'guaranteed service level' component The AER sets the performance indicators and NSPs needed to submit annual compliance report	ERC specifies the indices of Network Performance and Service Performance Network performance measures: • System average interruption frequency index • Customer average interruption duration index • Planned system average interruption duration index • Voltage regulation • Service losses Service performance measures: • Time to process applications for Regulated Distribution Services • Time to connect premises to the Regulated Distribution System after compliance with all government and Regulated Entity requirement • Percentage of calls answered at the call center within a predetermined time Each indicator will be weighted when calculating the performance factor	TNB business entities recommend a list of 3 operational performance indicators and demonstrate that they comply with the criteria: • Relates closely to the business activities of the TNB business entities; • Highly valued by electricity customers; • Can be objectively measured; and • Can be independently audited Take into consideration performance standards set in other international jurisdictions, which have implemented incentive-based regulatory frameworks for electricity industries

Note: TNB is Tenaga Nasional Berhad, the only electric utility in Peninsular Malaysia.
Source: LEI, AER, ERC, ST Malaysia, etc.

Hawaii can learn from these jurisdictions that have extensive/ongoing PBR regimes from many perspectives:

- **General guidelines are needed for the PBR transition:** guidelines from the markets provide a brief background on the purpose of the PBR transition and how they relate to the energy regulations and the powers of the Commission. In Hawaii, the Ratepayer Protection Act 005 and the PUC Order 35411 provided some guidelines on the goals of the PBR.

- **Targets should be balanced:** targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control.

- **The relationship of capital expenditure ("capex") and operating expenditure ("opex") should be clarified:**

    - recognition of national policies and how these policies impact the utilities;

    - clear efficiency scheme; and

    - encouragement of innovative projects.

- **Risk management mechanisms are needed:** in successful PBR regimes, the regulator has provided appropriate tools to manage risks to customers and the utility for factors that are beyond the utility's control. The three jurisdictions have exogenous factors, offramps, and reopeners to mitigate the risks.

- **Utilities need an appeal process:** jurisdictions allow for an appeal process to provide the utilities the opportunity to review the Regulator's decision.

- **Finally, a PBR design needs to be customized to the specific environment and circumstances of the regulated utility**:

    - A regulatory framework from another jurisdiction or utility may not work as well in another utility because of numerous factors such as inherent economic and market differences, business practices, policy-driven obligations, and regulatory or institutional requirements.

    - The regulator needs to take the utility's unique characteristics, type of customers served, and underlying economy into account.

5.3 Co-ops that are under lighter regulation from PUC

There are over 834 distribution and 63 generation and transmission ("G&T") cooperatives in 47 states.[158] PUCs regulate their tariffs in only 16 of the 47 states that have electric cooperatives.[159] However, it is worth noting that KIUC is different from most of the co-ops, i.e., distribution cooperatives, as KIUC is a vertically-integrated utility that owns generation, transmission, and distribution. Thus, the Project Team reviewed states that have co-ops that own generation, and found that Alaska, Utah, and Colorado are the three states that have most co-ps that own

[158] NRECA. *2017 Fact Sheet*. January 31, 2017.

[159] NRECA International. *Guides for Electric Cooperative Development and Rural Electrification*. Page 8.

generation.[160] Figure 20 summarizes different regulation for G&T co-ops in Alaska, Colorado, and Utah.

Figure 20. Summary of lighter regulation for G&T co-ops in Alaska, Colorado, and Utah

Comparison	Alaska	Colorado	Utah
What is "lighter" for G&T coops	deregulation or reregulation if voted by the members	N/A*	G&T coops are exempted from regulation on "rates, fares, tolls, or charges"
What remains the same for G&T coops	certification and transfer of certification	regulated as public utilities by the PUC, under the same authority as are investor-owned utilities	any other regulation (except rates), including, but not limited to, investigations, safety, mergers and consolidations, etc.

*Note: In Colorado, distribution cooperatives could be exempted from public utilities law by a vote of their members, but G&T co-ops are explicitly not covered by this Article (See C.R.S. §§ 40-9.5-102; 40-1-103(2)(a) & (b)(I))

As analyzed above, Alaska Statutes allows cooperatives to be exempt from the regulation by the Regulatory Commission of Alaska. Unlike Alaska, Colorado Legislation allows distribution co-ops to be exempt from PUC regulation, but this does not apply to G&T electric cooperatives.[161] The Utah Public Service Commission has jurisdiction over cooperative owned public utilities,[162] but the Utah Legislation states that the PUC does not have rate regulation authority over wholesale electrical co-op, i.e., Deseret Generation & Transmission Cooperative.[163]

However, unlike Alaska, Utah Legislation only allows "lighter" regulation rather than "deregulation" for G&T co-op. As stated in Utah Legislation 54.4.1.1, the Utah Public Service Commission *"does not have the authority to regulate, fix, or otherwise approve or establish the rates, fares, tolls, or charges of"* a G&T cooperative.[164]

Nevertheless, G&T co-ops are "*not exempt from other areas of regulation including, but not limited to, regulation having an indirect effect on rates, fares, tolls, or charges but which does not constitute an*

[160] Data from S&P Global "Energy Companies by State" Screening. In terms of cooperatives with generation, Alaska has 12, Utah has 7, and Colorado has 7.

[161] Colorado Revised Statues. 40-9.5-102.

[162] Utah Department of Commerce. Division of Public Utilities. About the Division of Public Utilities. <https://publicutilities.utah.gov/about.html>.

[163] Utah Code. 54-4-1.1. <https://le.utah.gov/xcode/Title54/Chapter4/54-4-S1.1.html>

[164] Utah Legislature. 54.4.1.1 Wholesale electrical cooperative exempt from rate regulation – requirements for rate increase. < https://le.utah.gov/xcode/Title54/Chapter4/54-4-S1.1.html?v=C54-4-S1.1_1800010118000101>

approval or establishment of them."[165] Moreover, the G&T co-op must hold a public meeting for all its customers and members prior to the implementation of any rate increase, and any schedule of new rates or other change that results in new rates must be approved by the board of directors of the G&T co-op.[166]

Based on the publicly available data, the Project Team reviewed the G&T co-ops that moved to be under lighter regulation in these jurisdictions in the past 20 years and decided to use Kodiak Electric Association in Alaska as a case for further analysis.

Kodiak Electric Association ("KEA") is a rural electric cooperative that owns generation and distribution in Kodiak, Alaska. KEA serves approximately 4,000 members,[167] about 16% of the 24,745 members served by KIUC.[168] In November 2004, KEA conducted a deregulation election and received 1,178 returned ballots (about 29% of its total members). Since the 1,178 ballots were more than 15% of its members (required for a valid election), the staff of Regulatory Commission of Alaska proceeded and tabulated the ballots. As a result, KEA was exempt from PUC's regulation including an investigation of rates, rules, regulations, practices, services, and facilities, under Alaska Statues 42.05 *Alaska Public Regulatory Act*.[169] However, the certification and transfer of certificate are still subject to the approval of the RCA.[170] And correspondingly, instead of annual regulatory cost charge, as an exempt utility, KEA shall pay the actual cost of services provided to it by the RCA.[171] Furthermore, deregulated cooperatives may elect to terminate its exemption (i.e., start reregulation by the RCA) in the same election procedure.[172]

Several lessons learned might be helpful for Hawaii:

- **There is no single format of "lighter" regulation:** as illustrated above, different states have a different approach in regulating co-ops, especially co-ops with generation. G&T co-ops are under varying levels of regulation in Alaska, Colorado, and Utah.

---

[165] Ibid.

[166] Ibid.

[167] Kodiak Electric Association. *Distribution*. Access Date: July 5, 2018. Web. <http://www.kodiakelectric.com/distribution.html>

[168] KIUC. *About Us*. Access Date: July 5, 2018. Web. <http://website.kiuc.co-op/content/about-us>

[169] Alaska Statues. 42.05.141 General Powers and Duties of the Commission. <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section141.htm>

[170] Alaska Statues. 42.05.711 Exemptions. (h) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section711.htm>

[171] Alaska Statues. 42.05.254 Public Utility Regulatory Cost Charge. (a) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section254.htm>

[172] Alaska Statues. 42.05.712 Deregulation Ballot. (h) <http://www.touchngo.com/lglcntr/akstats/Statutes/Title42/Chapter05/Section712.htm>

- **The design of lighter regulation for KIUC should be suitable to KIUC's unique characteristics**: different from distribution co-ops or G&T co-ops, KIUC is a vertically-integrated utility. Regulation over a vertically-integrated co-op, like KIUC, might differ from regulation over distribution co-ops and/or G&T co-ops. Further analysis is required to determine where and when greater or lighter regulation is needed for a vertically-integrated co-op like KIUC.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.2.2 Assessment of current markets under each regulatory model, including a case study, analysis, and conclusions.

CONTRACTOR shall provide examples of current markets under each regulatory model and provide examples of markets that have changed regulatory model in the last 20 years. CONTRACTOR shall provide the outgoing and incoming regulatory and ownership models: 1) number of utilities serving the market; 2) number of customers served; 3) capacity; 4) annual sales; 5) average fixed and variable retail rates; and 6) utility credit rating of each utility in the market before regulatory change and each year after regulatory change as data is available.

DELIVERABLE FOR TASK 2.2.2. CONTRACTOR shall provide its conclusions and all work related to current markets under each regulatory model including a more detailed assessment of the regulatory models and a case study of one jurisdiction under each of the regulatory models that is currently under that regulatory model. CONTRACTOR shall include an analysis of six to ten jurisdictions that have changed regulatory models, focusing on identifying at least one example for each of this study's regulatory models. The CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Word and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.2 to the STATE for approval.

7 Appendix B: List of works consulted

"About the RO." *Ofgem.* <https://www.ofgem.gov.uk/environmental-programmes/ro/about-ro>

"About Us." *PSEG Long Island.* <https://www.psegliny.com/page.cfm/AboutUs> Access Date: April 23, 2018.

"Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/pgc/pgc.aspx> Access Date: April 23, 2018.

"Certification and Licensing." *PUCT.* <https://www.puc.texas.gov/industry/electric/business/rep/rep.aspx> Access Date: April 23, 2018.

"Distribution Price Control Review (DPCR) 5." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls/distribution-price-control-review-dpcr-5>

"Electric Power Markets: Texas (ERCOT)." *FERC.* <https://www.ferc.gov/market-oversight/mkt-electric/texas.asp> Access Date: April 23, 2018

"Glossary." *Elexon.* <https://www.elexon.co.uk/glossary/british-electricity-trading-and-transmission-arrangements/>

"Local Transmission Owner Planning Process." *NYISO.* <http://www.nyiso.com/public/markets_operations/services/planning/process/ltpp/index.jsp> Access Date: April 23, 2018.

"Network Price Controls." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls>

"New York State Profile and Energy Estimates." *US Energy Information Administration.* <https://www.eia.gov/state/?sid=NY>

"Regional Data." US Department of Commerce. <https://www.bea.gov/iTable/index_regional.cfm>

"RIIO-ED1 Network Price Control." *Ofgem.* <https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/riio-ed1-network-price-control>

"The GB Electricity Distribution Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network>

"The GB Electricity Transmission Network." *Ofgem.* <https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network>

"Transmission and Distribution Utilities in Competitive Retail Areas." *PUCT.* <http://www.puc.texas.gov/industry/maps/electricity.aspx> Access Date: April 23, 2018.

"Transmission Overview." *NYPA.* <https://www.nypa.gov/power/transmission/transmission-overview> Access Date: April 23, 2018.

"Transmission/Distribution Service Providers." *ERCOT.* <http://www.ercot.com/services/rq/tdsp> Access Date: April 23, 2018.

"United Kingdom." *The World Bank*. <https://data.worldbank.org/country/united-kingdom>

2015 New York State Energy Plan Frequently Asked Questions. Web. <http://energyplan.ny.gov/-/media/nysenergyplan/2015-faqs.pdf>

Association of Electric Companies of Texas Inc. *The Wholesale Electric Market in ERCOT.* 2017.

Australia Competition and Consumer Commission. *Regulatory Practices in Other Countries Benchmarking opex and capex in energy networks.* May 2012.

DBEDT. *2016 State of Hawaii Data Book. Section 17 - Energy and Science*. 17.10 Electric Utilities, by island. 2016.

Department of Public Service. New York State. *Reforming the Energy Vision*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: April 20, 2018.

EIA. *Electricity statistics*. Website. <https://www.eia.gov/electricity/state/>. Access Date: April 24, 2018.

EIA. *New York State Profile and Energy Estimates*. Web. <https://www.eia.gov/state/analysis.php?sid=NY>. Access Date: April 20, 2018.

ERCOT. *Company Profile - History*. Web. <http://www.ercot.com/about/profile/history>. Access Date: May 4, 2018.

FERC. *CAISO market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/california.asp>. Access Date: April 24, 2018.

FERC. *Electric Power Markets: New York (NYISO)*. Web. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 20, 2018.

FERC. *ISO-NE – History*. Website. <https://www.iso-ne.com/about/what-we-do/history/>. Access Date: April 24, 2018.

FERC. *Midwest*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/midwest.asp>. Access Date: April 24, 2018.

FERC. *New York market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>. Access Date: April 24, 2018.

FERC. *PJM market*. Website. <https://www.ferc.gov/market-oversight/mkt-electric/pjm.asp>. Access Date: April 24, 2018.

FERC. SPP. Website. <https://www.ferc.gov/market-oversight/mkt-electric/spp.asp>. Access Date: April 24, 2018.

Governor David A. Paterson. *2009 State Energy Plan Volume I*. December 2009. page 6.

Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

IESO. *Corporate-IESO*. Website. <http://www.ieso.ca/en/corporate-ieso>. Access Date: April 24, 2018.

LEI. *LEI Semi-annual Regional Market Update and 10-year Energy and Capacity Price Forecast: New York.* 3rd Quarter 2017.

LEI. *LEI Semi-annual Regional Market Update and 10-year Energy Forecast: ERCOT.* 3rd Quarter 2017.

New York Public Service Commission. *Competitive Opportunities Regarding Electric Service, No. 94-E-0952.* March 6, 1996.

New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

New York State Energy Planning Board. *Report on the Reliability of New York's Electric Transmission and Distribution Systems.* November 2000.

New York State. *2002 New York State Energy Plan. Executive Summary*. Page S-3.

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, (issued February 26, 2015) (Track One Order).

NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Instituting Proceeding, (issued and effective April 25, 2014).

NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

NYISO. *2017 Load & Capacity Data Report ("Gold Book").* April 2017.

NYISO. *Transmission and Dispatching Operations Manual 2016.* December 1, 2016.

Ofgem, *Regulating Networks for the Future RPI-X 20 Emerging Thinking,* (London: 2010)

Ofgem, RIIO – A New Way to Regulate Energy Networks, (London: Ofgem, 2010)

Ofgem. *Electricity Distribution Price Control Review Final Proposals – Cost Assessment.* London: Ofgem, 2009

Ofgem. *Renewables Obligation: Annual Report 2016-17.* March 21, 2018.

Ofgem. *RIIO-ED1 Annual Report: 2016-17.* December 19, 2017.

Ofgem. *State of the Market Report.* October 31, 2017.

Province of Alberta. *Electric Utilities Act (Statutes of Alberta, 2003, Chapter E-5.1).* Website. <http://www.qp.alberta.ca/documents/Acts/E05P1.pdf>. Access Date: April 24, 2018.

Public Utility Commission of Texas. *Power Generation Companies – Search.* Website. < https://www.puc.texas.gov/industry/electric/directories/pgc/search_pgc.aspx>. Access Date: April 24, 2018.

PUCT. "About the PUCT.". <https://www.puc.texas.gov/agency/about/mission.aspx> Access Date: April 23, 2018.

PUCT. *2017 Scope of Competition in Electric Markets in Texas.* January 2017.

PUCT. *Retail Electric Providers*. < https://www.puc.texas.gov/industry/electric/directories/rep/alpha_rep.aspx>. Access Date: May 10, 2018.

S&P Global Market Intelligence. Regional Summary Statistics. <https://platform.mi.spglobal.com/web/client?auth=inherit#industry/summaryStatistics> Access Date: April 17, 2018.

The Association of the Bar of the City of New York. *Electric Regulation in the State of New York.* February 9, 2007.

UK Department for Business, Energy & Industrial Strategy. Digest of United Kingdom Energy Statistics (DUKES) 5.1, 5.5, 5.7, 5.10. July 27, 2017.

US Census Bureau**.** *State Population Totals and Components of Change: 2010-2017.* January 18, 2018

Preliminary and High-Level Assessment of the Regulatory Models' Technical, Financial, and Legal Feasibility

A working paper prepared by London Economics International LLC for the State of Hawaii with support from Yamamoto Caliboso for the State of Hawaii

August 23, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group and Yamamoto Caliboso, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, responding to Task 2.2.3 in the project scope of work, is one of several working papers developed to support the study. Several regulatory models were reviewed, (1) status quo with increased oversight [the Hawaii Electricity Reliability Administrator ("HERA") model], (2) independent grid operator ("IGO") model, (3) distribution-focused regulatory model [the Distributed System Platform Provider ("DSPP") model], (4) three performance-based regulation ("PBR") models, and (5) Lighter Regulation for cooperatives model (the "Lighter Regulation" model). The current regulatory model, the status quo, is assessed in Task 2.1.2 (High-level and general assessment of the existing regulatory model in place in Hawaii).

Table of Contents

Table of Figures

List of acronyms

ADMS	Advanced Distribution Management System
BNMC	Buffalo Niagara Medical Campus Inc.
BPS	Bulk power system
Capex	Capital expenditure
Co-op	Cooperative
COS	Cost-of-service
DBEDT	Department of Business Economic Development and Tourism
DER	Distributed energy resource
DERMS	Distributed Energy Resource Management Systems
DSIP	Distributed System Implementation Plan
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESM	Earnings sharing mechanism
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries
HELCO	Hawaiian Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HRS	Hawaii Revised Statute
IGO	Independent Grid Operator
IOU	Investor-owned utility
IPP	Independent power producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners

NERC	North American Electric Reliability Corporation
Ofgem	Office of Gas and Electricity Markets
P2P	Peer-to-peer
PBR	Performance-based regulation
PIM	Performance incentive mechanism
POC	Points of control
PPA	Power purchase agreement
PSR	Platform Service Revenue
PUC	Public Utilities Commission
PUCT	Public Utilities Commission of Texas
PV	Photovoltaic
RE	Reliability Entity
REV	Reforming the Energy Vision
RTO	Regional transmission organization
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
UK	United Kingdom

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership and regulatory models, which can help facilitate the achievement of the State's energy goals. This working paper, which responds to Task 2.2.3 in the project scope of work, provides a high-level assessment of the technical, financial, and legal feasibility of various regulatory models.

Several utility regulatory structures were reviewed based on the scope of work provided and our evaluation of various additional potential arrangements. These models include (i) status quo with increased oversight [i.e., with Hawaii Electric Reliability Administrator ("HERA")], (ii) independent grid operator ("IGO") model, (iii) distribution-focused regulatory model (more specifically the distribution system platform provider or "DSPP" model), and (iv) performance-based regulation ("PBR"). A detailed assessment of the fifth and current regulatory model, the status quo, is provided in Task 2.1.2 (High-level and general evaluation of the existing regulatory model in place in Hawaii). Following this assessment, Task 2.2.6 (Recommendation for the three most beneficial models) will narrow down the evaluation of regulatory models to three recommended models through a ranking and weighting process.

Ultimately, the feasibility analysis (as presented in this paper) aims to assess the performance of the regulatory models with regards to the State's key criteria, namely the abilities of the models in achieving State energy goals, maximizing consumer cost savings, enabling a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs, and eliminating or reducing conflicts of interest in energy resource planning, delivery, and regulation. The high-level assessment will aid in understanding the long-term operational and financial costs and benefits of utility regulatory models that can serve each county of the State. It will also be useful in identifying processes to be undertaken in order to establish regulatory models successfully in the context of Hawaii's existing regulatory model.

In that regard, some of the key findings of the technical feasibility include:

- All the models should be able to comply with service, quality and reliability standards, with the presence of an independent monitor or the commission itself performing the role of enforcing standards.

- Three of the assessed models—HERA, IGO, and distribution models—entail the creation of new entities needed for their implementation. The Hawaii Public Utilities Commission ("PUC", or "the Commission") will play a pivotal role in the definition of mandate and scope during the creation of these new entities. These regulatory models—unlike the other models such as PBR and the status quo—face a significant implementation risk on how to design and create a new entity successfully.

- The models vary in their ability to achive the State's energy goals. Our high-level analysis suggests that the PBR model could be designed to incentivize achievement of the State goals directly while the IGO model may maximize efficiency gains at the expense of the State's broader policy goals. The HERA model is limited by the scope and mandate that remains at the discretion of the Commission while the DSPP model is promising but has a high level of implementation risks.

Below are some of the key findings on financial feasibility:

- For most of the models, the role of the utility in generation, transmission, and distribution will largely be unchanged, assuming that regulation remains unchanged. The IGO and the DSPP models—which require regulatory changes to allow for greater competition in generation—are exceptions to this issue.

- The financial requirements for the implementation of each model vary broadly across each model, with the IGO model likely to require the most significant implementation costs given the need for IGOs in each island. In comparison, the implementation costs for the PBR model will be less than that of the IGO because it does not require the creation of new entities; nonetheless, the PBR model would involve a far more intensive process for the PUC. The distribution-focused model could also require significant costs with the technical upgrades needed to facilitate the model. The HERA model has a legislated funding surcharge, but the scale of its implementation cost would depend on the ultimate scope of the entity's mandate. Should it be tasked with increased monitoring, the creation of new Hawaii-specific standards, and provision of standards training, costs would increase accordingly.

- The financial impact of each model on ratepayers also varies across each model, with the implementation costs driving the costs to customers. The efficiency gains in the market-based regulatory models (i.e., the IGO and DSPP models) could be offset by the implementation costs, market design, and commitment to transition by the Commission.

Below are some of the key findings on legal feasibility:

- A number of the models, particularly IGO and DSPP models, require relevant legal framework for successful implementation. Similarly, although a framework exists for the HERA and PBR models, an investigative docket or rulemaking proceeding is still likely required. In the case of the latter, a PBR proceeding is currently underway.

- The implementation of the proposed models requires addressing legal issues—including the status of existing power purchase agreements, fuel purchasing contracts, and the need to assure a reasonable return for prudently-made investments by utilities during previous regulatory regimes.

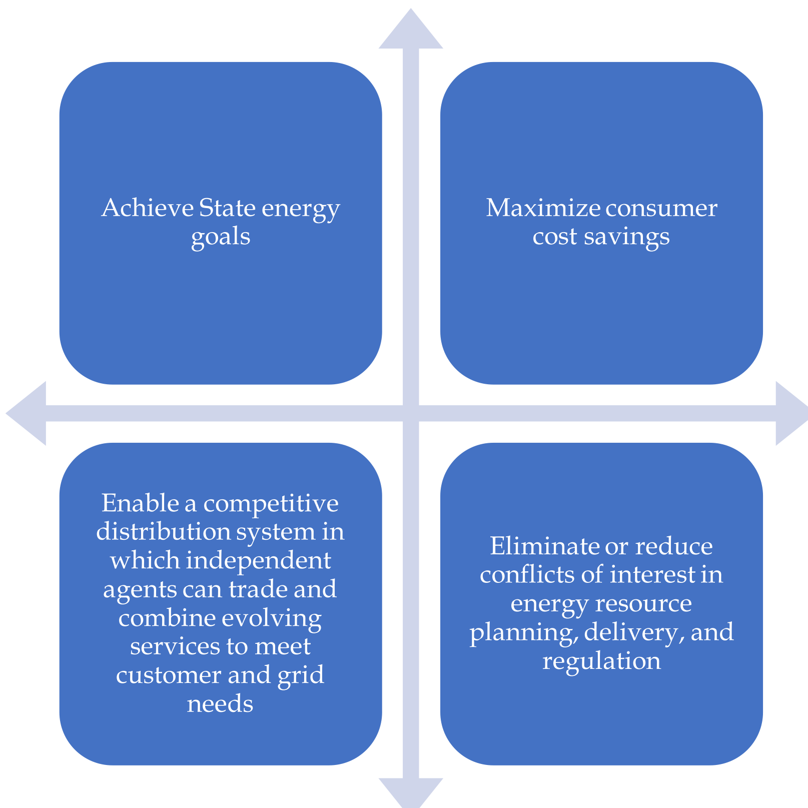
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State Legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models, which can support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement[1], was contracted to perform this study.[2]

The project aims to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] (Figure 1).

Figure 1. State's Key Criteria in Evaluating the Models



Source: Scope of Services under Contract No. 65595

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models that can best serve each county of the state. Moreover, it will also aid in identifying the process that must be followed in forming such ownership and regulatory models as well as determining whether such models would create synergies. Such synergies are beneficial in terms of increasing local control over energy sources serving each county, ability to diversify energy resources, economic development, reducing greenhouse gas emissions, increasing system reliability and power quality, and lowering costs to all consumers.[4]

2.2 Role of this deliverable relative to others in the project

This deliverable fulfills Task 2.2.3 in the project scope of work. It provides a broad analysis of the technical, financial, and legal feasibility of regulatory models proposed in previous tasks. It assesses these feasibilities in the context of Hawaii's existing regulatory model, providing the Project Team's assessment of the risks associated with their implementation.

Various aspects of the regulatory models will be further explored in subsequent deliverables. These include:

- summary analysis and conclusions related to estimating stranded costs for each regulatory model (Task 2.2.4);
- solicitation of public input on the results of Task 2.1.1 through 2.2.4 (Task 2.2.5) from each island currently served by an electric utility;
- identification of and recommendation for the three most beneficial regulatory models for further consideration (Task 2.2.6);
- identification of steps, costs, and projected timelines, if there will be a change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to help determine the required regulatory and legislative changes in the implementation of the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- assessment of how each recommended model impacts State agencies' staffing and stakeholders (Task 2.3.4);
- estimated potential of each model in increasing distributed energy resources (Task 2.4.1); and,
- evaluation of revenue requirements, system average retail rates, risks to utility valuations, and funding mechanisms of each regulatory model (Task 2.5).

[4] Hawaii Contract No. 65595. Scope of Services.

2.3 Future refinements

This deliverable is the Project Team's assessment of the feasibility of each of the proposed regulatory models, which may be subject to further improvement or change as the project moves forward and receives inputs from the stakeholder groups and results of the quantitative analysis and case studies become available.

The feasibility analysis is a high-level one—supplemented by case studies (included in Task 2.2.2)—allowing us to highlight the essential features of the different regulatory models and key issues and lessons from other jurisdictions or utilities.

The project will provide various opportunities for stakeholder inputs and participation. LEI will engage a wide range of stakeholders and perspectives across all islands through a series of facilitated dialogues, one-on-one meetings, and workshops.[5]

[5] A series of community meetings across the state was held in June 2018 in Hawaii. The workshops provided opportunities for the attendees as well as online participants to hear from key stakeholders in the energy policy discussion and provide inputs to the study through the small group discussions.

3 Key concepts

The Project Team conducted a high-level feasibility analysis of the technical, financial, and legal aspects of each regulatory model discussed in previous work papers. Feasibility, in the context of this study, attempts to determine the most effective, efficient, and viable regulatory model with which the State of Hawaii can achieve its energy goals.

"Inclinations" of the PUC on the Future of Hawaii's Electric Utilities

The PUC outlined key inclinations on the future of Hawaii's electric utilities to guide utility business strategy, energy resource planning, and project review. These guiding principles include:

- **Creating a 21st Century Generation System:** Hawaii currently relies heavily on oil-fired electricity generation, which is expensive compared to modern, clean energy technologies. Utilities should move urgently to capitalize on cost-saving opportunities by modernizing electricity generation with clean and efficient resources on all islands.

- **Creating Modern Transmission and Distribution Grids:** future electric grids must be designed as advanced networks that integrate greater quantities of customer-sited distributed energy resources ("DERs") and offer customers increased opportunities to manage their energy usage.

- **Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future:** the PUC noted that the HECO Companies[6] "*may not currently have the appropriate financial incentives*" to achieve Hawaii's policy goals. In particular, "*inherent financial conflicts*" related to utility ownership of generation and related compensation frameworks result in a "*lack [of] correct incentives to control power supply costs, aggressively pursue long-term contracts with IPPs for new renewable energy projects, and expeditiously retire old, inefficient generation units*." Utilities will need to transform their business models, such as by focusing on "*energy delivery*" and related grid modernization functions, rather than generation. Similarly, the PUC stated that it might need to transform regulatory frameworks, such as by setting up new financial incentive mechanisms, unbundling ancillary services from electricity pricing, and forbidding the ownership of new generation by utilities. These new business and regulatory models will enable utilities to meet rapidly changing customer, technical, and economic requirements.

Source: Hawaii Public Utilities Commission, "*Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities*," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.Hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf

---

[6] The term "HECO Companies" refers specifically to Hawaiian Electric Company ("HECO"), Maui Electric Company ("MECO"), and Hawaiian Electric Light Company ("HELCO"). The analysis within this report is not intended to apply to the American Savings Bank, which is a subsidiary of HEI. In some cases, the term "HEI" (for Hawaiian Electric Industries) is used to refer to the ownership entity of the HECO Companies.

In performing the high-level feasibility analysis, the Project Team drew heavily from available literature and guidelines of the PUC. More specifically, we looked at various statutes, PUC Decisions, and Orders. These include:

- The standards for electricity service as outlined in General Order No. 7 by the PUC;
- The performance metrics for electric utilities as outlined by the PUC;
- The responsibilities of the PUC as specified under Hawaii Revised Statute ("HRS"), particularly Title 15 "Transportation and Utilities," Chapter 269 "Public Utilities Commission;" and
- The "Inclinations" of the PUC for the clean energy vision of Hawaii as outlined in textbox.

3.1 Technical feasibility

Technical feasibility evaluates whether the regulatory model in question enhances or diminishes the utility's ability to carry out its roles and responsibilities. The PUC has identified the functions of an electric utility through various regulations and laws. These include provision of adequate and reliable energy supply, avoidance of interruption of services, compliance with standards set by the PUC, and maintainance of service quality (Box 2).

Moreover, the State has set explicit energy goals, some of which are listed below:

- to source 100% of electricity from renewable energy by 2045[7];
- to have a diversified energy portfolio that makes the best use of land and resources;
- to have integrated and modernized grids;
- to balance technical, economic, environmental, and cultural considerations;
- to leverage Hawaii's position as an innovation test bed; and
- to have an efficient marketplace that is beneficial to producers and consumers.[8]

Recognizing the said goals, this technical feasibility analysis considers whether the new regulatory model could help ensure that electric utilities can perform their responsibilities as directed by the PUC.

Major Responsibilities of an Electric Utility (non-exhaustive list)

PUC General Order No. 7 outlines the key standards for Electric Utility Service in the State of Hawaii. Moreover, the PUC has further outlined performance metrics that should accompany

[7] HRS § 269-92.

[8] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf.

such standards. The following summarizes some of the key responsibilities of an electric utility as well as the metrics for those responsibilities:

1. Provide an adequate and reliable electricity supply

Rule 5.3.a of General Order No. 7 states that the generation capacity of the utility's plants, supplemented by electric power regularly available from other sources, must be sufficiently large to meet all reasonably expectable demands for service and provide a reasonable reserve for emergencies. The performance metrics for this include Equivalent Availability Factor, Equivalent Forced Outage Rate-Demand, Equivalent Forced Outage Factor, and ratio of IPP Energy/Net to System Energy. These are performance indices, which are broadly used for availability of generation resources that provide power.

2. Avoid interruptions of service

Rule 7.5 of General Order No. 7 establishes that each utility shall make reasonable efforts to avoid interruptions of service but when interruption occurs, service shall be re-established within the shortest time practicable, consistent with safety. The performance metrics for this include the System Average Interruption Duration Index ("SAIDI"), which measures the average interruption time for all customers served during a given period of time, and the System Average Interruption Frequency Index ("SAIFI") which measures the average number of interruptions experienced by all customers served during a given time period.

3. Meet quality of service standards

The Hawaii PUC requires regulated utilities to continually achieve high quality of service standards. Quality of service includes aspects of customer service and technical services, involving both interactions and engagements between customers and HECO Companies. The performance metrics for this include the percentage of customer calls answered within 30 seconds and consumer transaction survey results.

Sources: Hawaii Public Utilities Commission, "*Hawaii General Order No. 7*," available at: https://puc.Hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf; Hawaii Public Utilities Commission, "*Approving the Release of Performance Metrics, Directing that the Approved Performance Metrics be Posted to the Websites, and Directing the Parties to Develop Additional Performance Metrics*," Order No. 32701, available at: http://dms.puc.Hawaii.gov/dms/DocumentViewer?pid=A1001001A15C12A92431G90153

3.2 Financial feasibility

Financial feasibility evaluates the reasonableness of the proposed regulatory model in financial and economic terms. Since "financial feasibility" can encompass many factors, this analysis is limited to the financial viability of the regulatory model and the financial impact on the ratepayers. The following are key questions that are considered in assessing the financial feasibility:

- How does the proposed regulatory model affect the financial viability of power sector participants?

- Are the utilities able to earn a fair rate of return with the change of the regulatory model?
- Are ratepayers likely to be better or worse off as a result of the implementation of the regulatory model?

3.3 Legal feasibility

Legal feasibility assesses whether the transition to another regulatory model is legally possible given the laws, statutes, and regulations currently in effect. This analysis considers legal requirements—whether new ones or revisions of existing ones—of the regulatory model under consideration. Policy interventions will likely vary depending on the requirements of the chosen regulatory model. Our analysis seeks to identify any significant legal challenges to the transition to another regulatory model. In doing so, our analysis draws heavily upon the regulatory frameworks established by the State Legislature and the PUC.

The key questions that inform the legal feasibility are listed below:

- Is there an existing legal framework for this regulatory model?
- Is the PUC authorized under the current legal and regulatory framework to implement the regulatory model under consideration?
- What statutory changes or laws, if any, are required to be enacted by the State Legislature to implement this regulatory model?
- What administrative actions must be undertaken by the PUC to implement this regulatory model?
- Are there any additional legal issues that could substantially affect the viability of this regulatory model?

4 Status quo with increased oversight

As discussed in previous working papers, the utility would continue to operate the transmission and distribution network under the status quo with increased oversight model. As in the status quo model, the utility would continue to be responsible for systems operations, system planning, and dispatch. Nonetheless, in this case, increased oversight would be leveraged through HERA, established by the Hawaii State Legislation (Act 166) in 2012.

While Hawaii State Legislature passed legislation allowing for the establishment of a HERA in 2012, no action has been taken yet toward its establishment. In 2012, the Hawaii PUC was authorized to "*contract for the services of a Hawaii electricity reliability administrator to support the commission in carrying out [critical functions] throughout the State.*"[9] As such, the Hawaii PUC may contract with a person, business, or organization (except a public utility) for the performance of HERA's functions.[10]

4.1 Technical feasibility

4.1.1 Requirements for establishment

The formation of an entity such as HERA is a voluntary process that must be initiated by the Commission. As such, the PUC would be required to commence stakeholdering, which can help decide upon various facets of HERA such as the entity's mission, responsibilities, budget, and staffing requirements. Once the PUC has gathered inputs from the stakeholders, the Commission staff would issue a draft proposal reflecting the purpose and characteristics of such an entity. The proposal would serve as a foundation for further stakeholdering, from which the Hawaii PUC would be able to establish final qualification requirements, for example, the issuance of the rule or order creating HERA.

The Hawaii PUC would then select the HERA via a competitive procurement mechanism. The contract to act as HERA could be awarded through a competitive bid, scored request for proposal, or sole source procurement in certain situations, as per HRS 103D.[11] Based on the budget established via the final PUC order, the Commission would establish an electricity reliability surcharge, which would be collected to support the operations of the newly established HERA.

---

[9] Hawaii House Bill No. 2525 (2012).

[10] HRS 269-147.

[11] Mayor's Office of Economic Development, Energy Commissioner, DKK, and SES. *Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui.* August 25, 2017. Page 63.

Furthermore, the Hawaii PUC would need to hire an Executive Director for HERA, who would then appoint the staff of the organization. Staff members would be required to have appropriate skills and levels of independence, which can enable them to develop and review reliability standards and interconnection requirements. While the HECO Companies' staff members would serve as the obvious choice, their hiring for the newly established HERA would raise some red flags. As such, the PUC would also need to create rules surrounding conflict of interest. More specifically, the PUC would need to study rules that ISOs or PUCs implement regarding hiring from regulated entities.

Once established, HERA would review matters pertaining to reliability and interconnection and thereby report on its operational and financial status to the Hawaii PUC on an annual basis.[12] Textbox gives more details on the role of HERA.

The Role of HERA

The entity acting as HERA would be required, under existing statute, to meet certain requirements such as (1) satisfying any qualifications established by the PUC by rule or order; (2) maintaining reasonable and necessary staffing of individuals who have skills and expertise to offer recommendations on the development of reliability standards and interconnection requirements, and appropriate level of independence to fairly and impartially review matters concerning interconnection to the Hawaii electric system.[1] HERA would be funded by funds collected through the Hawaii electricity reliability surcharge and it will be required to report to the PUC annually on the status of its operations, financial position, and projected operation budget for the following fiscal year.

Sources: HRS § 269-148; HRS § 269-149 (a) (b).

As discussed in Task 2.1.1, an alternative to HERA is the "Light" HERA, which could be designed as an ombudsman, an appeals body focused on hosting capacity and interconnection. The technical requirements and processes in the establishment of Light HERA would be the same as the "regular" HERA; the difference would largely be on responsibilities and tasks.

4.1.2 Impact on the roles and responsibilities of the Commission

When forming this new entity, the Hawaii PUC will seek to define HERA's mandate because the definition provided by the legislation offers a broad scope for its functions, i.e., to ensure necessary electric system reliability and grid access oversight functions. Currently, the PUC is responsible for several regulatory functions—including monitoring reliability and service quality—in the Hawaii power sector. In this role, the PUC is responsible in ensuring that the Hawaii electric system complies with all adopted reliability standards including those for interconnection.[13] The creation of HERA would require the PUC to hand over at least some of these responsibilities to the new entity as well as create new roles for the functions it would be required to perform. Insofar as the role of HERA requires greater visibility of the power system

[12] Ibid.

[13] HRS Chapter 269-144. *Compliance and enforcement.* HI Rev Stat § 269-144 (2017)

contact:
Mugwe Kiragu/Shrutika Sainani
617-643-6626
mugwe@londoneconomics.com

than the Commission currently does, its creation may warrant more technical and human resource capability.

4.1.3 Impact on the roles and responsibilities of utilities

Under this new regulatory model, the utilities would be required to improve and increase their reliability reporting frequency and visibility. The utilities may also be directed to provide availability and outage data, as is required by Reliability Entities ("REs") that function under the North American Electric Reliability Corporation ("NERC") jurisdiction. Typically, this is done through a portal managed by Open Access Technology International, where regional RE bodies provide coordination, analysis, user training, and support for the collection of performance data that are required for analysis of open access.[14] Utilities would require increased investment in IT and staffing in order to comply with the requirements of the PUC, such as toward increased reliability reporting frequency and visibility.

4.1.4 Compliance with reliability, adequacy, and quality of service standards

The HERA model would strengthen the utilities' compliance further with reliability and adequacy. Under the HRS Chapter 269 statutes, the PUC may "*make provisions for the Hawaii electric reliability administrator to recommend penalties and enforcement to the commission.*"[15] This provision would allow the HERA entity to be more effective in its monitoring role as it supports the Commission in the oversight of reliability and service quality standards. An empowered monitoring and compliance entity would assist the Commission in its assessment of supply adequacy in light of the State's 100% renewable energy goals. Furthermore, an independent entity constituted to focus on service quality standards is likely to take a long-term approach to ensure utilities and other suppliers maintain standards as prescribed by the Commission.

4.1.5 Ability to achieve State energy goals

HERA is expected to support the Commission in its oversight of reliability and interconnection access, through which it should enforce the State's goal of fair and transparent grid access. Among the most significant challenges for greater DER penetration is ensuring fair access to the utility grid because utilities are inclined to favor their own systems ahead of third-party access to their networks. Ensuring reliable supply, as Hawaii pursues its 100% renewable goal, is also of paramount importance as the State seeks to ensure that the increased penetration of renewable energy does not lead to a decline in the quality of supply for customers. Currently, only two reliability metrics are measured by the utilities, which have penalties. Transferring the responsibility of enforcing and monitoring reliability to HERA could ensure that reliability will not be an issue as the state tries to achieve its renewable energy goals. In addition to implementing reliability standards across the electric value chain, HERA's mandate also includes providing fair

---

[14] Texas Reliability Entity. *Reliability Data Systems.* Accessed at https://www.texasre.org/Pages/reliability.aspx

[15] HRS Chapter 269-144. *Compliance and enforcement.* HI Rev Stat § 269-144 (2017)

grid access to generators.[16] This could open more opportunities for more renewable generators and DER providers. Further details regarding the regulatory model's ability in facilitating the State's energy goals can be found in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to the state goals).

4.2 Financial feasibility

4.2.1 Financial requirements for implementation

Under the provisions of the implementation law, "*this Act allows for the creation of a surcharge affecting users and operators of the Hawaii electric system to be collected for the purpose of maintaining system reliability.*" Furthermore, under the implementation statutes, HRS Chapter 269-146, the Commission is empowered to use the surcharge such that "*amounts collected through the Hawaii electricity reliability surcharge shall be transferred in whole or in part to any entity contracted by the commission to act as the Hawaii electricity reliability administrator provided for under this part.*"[17] Therefore, users' surcharge in the Hawaii electric system would be one of the sources of funding for the establishment and operations of HERA.

An example can be drawn from the Texas RE, which serves as the Electric Reliability Organization ("ERO") for the State of Texas. The Texas RE is responsible for monitoring reliability standards in the State and its experiences and as Texas does not lie within FERC jurisdiction, could provide lessons for the adoption of the HERA model particularly that Texas does not lie within FERC jurisdiction. Similar to HERA, the Texas RE receives its funding from a surcharge on the net load; this funding model is described further in the textbox below.

Texas Reliability Entity

Texas RE is responsible for reliability coordination in the Electricity Reliability Council of Texas ("ERCOT") ISO footprint. Within this region, which covers 75% of the Texas area and accounts for ~80% of the load in the State, Texas RE is responsible for monitoring and reporting on reliability standards in the bulk power system ("BPS").

Entities participating in the power sector in the State of Texas are regulated by the Public Utilities Commission of Texas ("PUCT"). Primarily, Texas RE is responsible for developing, monitoring, assessing, and enforcing compliance with reliability standards; developing regional standards; and evaluating and periodically reporting on the reliability and adequacy of the BPS. Texas RE also serves as the reliability monitor for the PUCT of the ERCOT region—which means that it monitors both NERC and State reliability standards.

[16] Hawaii Senate Bill 2787 (2012).

[17] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

Texas RE is a voluntary participation organization and there is no cost to join the entity, i.e., it charges no membership fee to any qualifying entity, which is defined as any entity that is a user, owner, or operator in the ERCOT region BPS.

Texas RE obtains its funding from a number of different sources. Its primary source—known as ERO funding—is from NERC. This is derived from NERC Assessments and Penalty Sanction fees. The NERC Assessment funding is obtained from end-users, allocated based on net energy for load, and approved by the FERC. In 2016, NERC indicated that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.0000389 per kWh, based on the aggregate net energy for load of the United States in 2015. For the year 2016, the Texas RE's total budget was approximately $11.8 billion.

Texas RE also obtains funding for state obligations, i.e., serving as reliability monitor for the PUCT. For this, it is funded through ERCOT ISO's system administration fee, which is sanctioned by the PUCT. This comprised approximately 10% of its total funding budget in 2017.

Sources*:* Texas RE. *2017 Annual Report;* Texas RE. *2017 Business Plan and Budget;* FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

4.2.1 Financial impact on the Commission, utilities, and ratepayers

With the implementation of HERA, ratepayers would likely see an increase in their monthly bills. As mentioned earlier, the statutes allow the Commission to impose a surcharge to help cover the operations of HERA.

The Project Team assumes that HECO Companies' costs related to regulatory affairs would most likely increase, too, because they would need to increase reliability reporting frequency and visibility. This would mean a potential increase in investment in IT and staffing in order to comply with the requirements of HERA.

The statutes indicate that utilities would be allowed to recover "*appropriate and reasonable*" costs from ratepayers under the reliability surcharge to finance several activities related to reliability and open access. These activities including interconnection to the Hawaii electric system, relevant interconnection studies, and other analysis required in understanding the impact of necessary infrastructure and operational systems to interconnection reliability.[18]

4.3 Legal feasibility

4.3.1 Existing legal framework for the regulatory model

Under the Status Quo with HERA, Part IX, Electric Reliability, of Chapter 269, HRS ("HERA Law"), including the retention by the contract of a HERA by the PUC is assumed to be

[18] Ibid.

implemented.[19] Under the consideration that authorization has passed, the existing legal framework should not present challenges in accommodating the HERA regulatory model.

4.3.2 PUC authority under current legal and regulatory framework

As briefly discussed earlier, the Legislature authorized the PUC to adopt reliability standards and interconnection requirements,[20] so it can monitor the reliability and operation of the Hawaii electric system,[21] enforce compliance with reliability standards and interconnection requirements, including imposing reasonable penalties,[22] oversee requested interconnections with the Hawaii electric system, and make determinations in any disputes.[23] The PUC is required to "*consider the value of improving electrical generation, transmission, and distribution systems and infrastructure within the State through the use of advanced grid modernization technology in order to improve the overall reliability and operational efficiency of the Hawaii electric system*."[24] The PUC is also authorized to require a surcharge for connecting to the Hawaii electric system.[25]

Under the current statutory framework (HERA Law), the PUC is authorized to contract the performance of the PUC's functions to a third party (and serve as HERA) through a solicitation process.[26] However, a public utility is prohibited to serve as HERA and the PUC may not contract such for the performance of its functions, which include the (1) adoption of reliability standards and interconnection requirements under HRS § 269-142(a) and (b); or (2) creation of the Hawaii electric reliability surcharge.[27]

Pending contracting with a third party to act as HERA, the PUC has explained that it would continue to perform its functions under the HERA Law and effectively serve as HERA until such a body is formally established:

---

[19] *See* HRS Chapter 269, Part IX (Electric Reliability); HRS § 269-147.

[20] HRS § 269-142.

[21] HRS § 269-143; HRS § 269-141 provides that, "'Hawaii electric system' means all electric elements located within the State together with all interconnections located within the State that collectively provide for the generation, transmission, distribution, storage, regulation, or physical control of electricity over a geographic area; provided that this term shall not include any electric element operating without any interconnection to any other electric element located within the State."

[22] HRS § 269-144.

[23] HRS § 269-145.

[24] HRS § 269-145.5.

[25] HRS § 269-146.

[26] HRS Chapter 269, Part IX (Electric Reliability); HRS § 269-147.

[27] HRS § 269-147.

"*The commission recognizes that the development of HERA will require time to conduct the aforementioned HERA proceeding, to retain a potential contractor to perform HERA functions and secure a source of funding for HERA. In the interim, the commission will continue to effectively serve as HERA, until formally established. The commission's consultant for the RSWG process will continue to support the commission on reliability, interconnection, and system operational issues*."[28]

Currently, it does not appear that the PUC has already contracted the performance of its functions (to act as HERA) with any third party nor does it appear that a solicitation for bids has been issued under HRS Chapter 103D.

4.3.3 Statutory changes or laws required for implementation

There is no additional statutory change or law that needs to be enacted by the State Legislature to implement the HERA model assuming the PUC exercises its authority under the HERA Law, which provides the PUC with authority (but does not generally require it to implement the Law).

4.3.4 Administrative actions required by the PUC

To implement the HERA model (to the extent not already adopted or determined), the PUC would be required to adopt reliability standards and interconnection requirements by rule or order[29] and rules for the issuance of penalties,[30] establish procedures for interconnection with the Hawaii electric system by rule or order,[31] and set a surcharge for connecting to the Hawaii electric system by rule or order based on stakeholdering, as described in Section 4.1.1.[32] The PUC would also have to contract with a third party, which would serve as HERA as discussed above.[33]

If the PUC were to undertake any of the matters described immediately above, stakeholder input could be provided through the process that the PUC would utilize to take such actions, i.e., by "rule" or "order." If the PUC were to adopt rules, it the PUC would do so under the rulemaking process described in the Hawaii Administrative Procedures Act, HRS Chapter 91,[34] which requires public hearings.[35] If the PUC were to take an action by "order," it would do so under its

---

[28] *See* Order No. 32054 Ruling on RSWG Work Product, issued in Docket 2011-0206, on April 28, 2014, at 111-113.

[29] HRS § 269-142(a).

[30] HRS § 269-144(c).

[31] HRS § 269-145(a).

[32] HRS § 269-146(a).

[33] HRS § 269-147.

[34] HRS § 269-6(a) ("Included among the general powers of the commission is the authority to adopt rules pursuant to Chapter 91 necessary for the purposes of this chapter.")

[35] HRS § 91-3.

standard docket process under HRS Chapter 269. In this procedure, stakeholders can could provide input either as intervenors/participants or by more informal public comments or additional informal stakeholder processes that could be implemented by the PUC in such dockets. In contracting with a third party that can serve as HERA, the PUC would be required to utilize a competitive procurement process under the Hawaii Public Procurement Code and HRS Chapter 103D, which does not inherently include a stakeholder or public hearing process. However, the PUC can possibly, but is not required, to seek stakeholder feedback if it chose to do so while it is undertaking the contracting of the third party under the Hawaii Public Procurement Code so long as such actions would not violate the Hawaii Public Procurement Code.

4.3.5 Additional legal issues

The current statute generally authorizes but does not mandate the performance of the PUC's functions (including contracting with a third party to serve as HERA) under the HERA Law.[36] If the HERA model is deemed to be needed, the Legislature may amend the law to mandate the performance by PUC of its functions under the HERA Law, with appropriate deadlines.

4.4 Conclusion

The feasibility of this model is dependent in part to the scope and scale of the mandate that is given to the HERA entity by the Commission. This discretion would allow the Commission to define how narrow or broad its mandate would be. This would, in turn, determine the scale of the surcharge needed to fund the new entity. However, as described above, similar entities exist on the mainland. An example is Texas RE, which illustrates the possible interactions the HERA entity would have with other power sector entities and a working framework that exists outside the jurisdiction of FERC.

Possible uncertainties include the lack of clear scope definition that lies with the Commission and questions over enforcement. Therefore, it ranks as *neutral to low risk* in terms of overall feasibility. A summary of the feasibility criteria considered is given in Figure 2.

---

[36] HRS § 269-147.

Figure 2. HERA Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+/-) Depends on scope of mandate of HERA
	Compliance with service standards	(+) Increased reporting frequency and visibility
	Achievement of State clean energy goals	(+) Promote DER integration and penetration
Financial Feasibility	Implementation requirements	(+) Surcharge already defined in legislation
	Impact on ratepayers	(+) Costs are expected to be borne by ratepayers
	Impact on utilities	(+) Increased reporting requirements and facilitation of open access requests
Legal Feasibility	Existence of supporting legal framework	(+) No additional statutory changes or laws needed
	Governance requirements	(+) No additional statutory changes or laws needed
	Additional legal factors	(-) Existing statute does not mandate PUC performance

Source: LEI analysis

5 Independent grid operator

An independent system operator ("ISO") or a regional transmission organization ("RTO") is an independent, membership-based, nonprofit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[37] The concept of an ISO came from Order Nos. 888/889, followed by the introduction of the concept of an RTO in Order No. 2000 by the Federal Energy Regulatory Commission ("FERC").

As per Order No. 2000, the minimum characteristics of an RTO include independence, scope, regional configuration, operational authority, and short-term reliability.[38] FERC's minimum functions as an RTO include tariff administration and design; congestion management; parallel path flow; ancillary services; establishment of or participation in a transparent system for data access; monitoring, computing, and managing of transmission capacity; market monitoring; planning and expansion; and interregional coordination.[39]

Hawaii is not part of FERC so the scope of work of the ISO could be tailored to the needs of the state, taking its size and unique features into account. For the purpose of the Study, the Project Team assumes that the responsibilities of the ISO in Hawaii, as discussed in previous working papers, include dispatch and resource planning. Moreover, the ISO under the Hawaii context would cover both the transmission and distribution sectors, thus, will be called the independent grid operator ("IGO").

5.1 Technical feasibility

5.1.1 Requirements for establishment

While the State of Hawaii does not lie within FERC and NERC jurisdictions, an IGO can also be formed for the purposes of system planning and dispatch in each island without participating in interstate commerce. Nonetheless, the State of Texas provides an example of how a state can still achieve the objectives outlined in FERC Order 888. ERCOT is an ISO that operates the transmission system within the boundaries of the state, representing 90% of Texas load, and is only interconnected to other grids by way of DC Ties and Block Load Transfers, thereby making it an "electrical island."[40]

To establish an IGO, the Legislature would first need to enact legislation to ensure open access for wholesale electricity market participants, the functional unbundling of transmission service,

---

[37] "Today in Energy." *EIA*. Website. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=790. Access Date: April 19, 2018.

[38] FERC. *Regional Transmission Organizations* (Issued December 20, 1999). (Docket No. RM99-2-000; Order No. 2000), page 151.

[39] Ibid., page 323.

[40] "ERCOT Nodal 101." *ERCOT.* Training. Website. Accessed at http://www.ercot.com/services/training/course/109518. Access Date: May 19, 2018.

and the establishment of open access transmission tariffs, thereby opening doors to competitive wholesale generators and ensuring open access to the transmission system. With sufficient and appropriate legislative authority, the PUC would subsequently direct the establishment of an IGO—a non-profit third-party organization that will oversee equal access to the power grid—for each county. As such, for each county, a Board of Directors must be set up to oversee the IGO's operations, budget approval, staffing, establishing market rules, and approving subsequent changes. The IGO would then acquire existing dispatch, monitoring, and control equipment from the incumbent utilities in order to manage the transmission/distribution system. Market protocols would be developed by the IGO through stakeholder collaboration.

5.1.2 Impact on the roles and responsibilities of the Commission and utilities

Under the IGO model, utilities would continue to own and maintain the transmission and distribution system. However, utilities would need to yield their functions of system planning, dispatch, and day-to-day operations to the IGO. Under an IGO model, the incumbent utility could either retain its generation assets or divest them. Unlike the status quo model, this change would allow independent power producers ("IPPs") to compete with the HECO Companies on price (assuming a level playing field) over long-term contracts.

When it comes to roles, the PUC would continue to do most of its current responsibilities. These include the approval of resource planning, power purchase agreements ("PPAs"), financial transactions, large capital expenditures, service quality, and the regulation of rates. However, functions such as the coordination of movement of electricity, reliability, and long-term resource planning however, would be under the IGO's purview.

5.1.3 Compliance with reliability, adequacy, and quality of service standards

An IGO regulatory structure aims primarily to ensure that reliability standards are met. This would not only require collaboration on the part of the IGO itself but also amongst transmission owners and generators. In general, IGOs ensure that adequacy and reliability requirements are met by matching generation with demand with a least-cost combination of resources.

An IGO model would help utilities comply with reliability, adequacy, and quality of service standards established by the PUC. would contribute to maintenance and improvement of grid reliability by way of coordinating short-term grid operations. More specifically, the IGO would be responsible for functions such as:

- operational control of the transmission system within the region, security coordination, administration of the IGO tariff,
- operations of the transparent data access system, allocation of available transfer capability,
- provision or coordination of ancillary services, participation in transmission planning,
- implementation of congestion management procedures,

- coordination of generation and transmission, and maintenance scheduling.[41]

To ensure efficiency, an IGO must also identify constraints in the system and take necessary actions to alleviate the constraints within the trading rules established by the PUC.[42]

On the other hand, the transmission owners hold a set of different responsibilities. They may be responsible for functions such as maintenance of ownership of transmission facilities, physical operations and maintenance of transmission facilities, power systems analysis, transmission planning studies, and construction of new transmission facilities.

5.1.4 Ability to achieve State energy goals

The IGO model would be able to facilitate the achievement of some of the State energy goals such as in allowing improved market performance through the mitigation and/or elimination of market power as well as for increased competition within the marketplace (protecting consumers from monopoly power). More specifically, the IGO model would be able to facilitate the development of large renewable projects by increasing competition among utility-scale projects. As an independent body, system planning conducted by an IGO would also allow renewables to compete based on cost and value to the grid. However, without new initiatives, an IGO model at a distribution level would not substantially expand opportunities for DERs to participate (as opposed to a distribution-focused regulatory model that specifically addresses this issue). Finally, an IGO may be designed in such a way that most of the State energy goals are addressed in its mandate.

5.2 Financial feasibility

As a not-for-profit, non-taxed entity, an ISO, such as the ones that are currently operating (PJM, New York ISO, and ISO-New England) funds the services it provides through the collection of fees from market participants and customers that use regional transmission services. Service rates are set at a level that allows the ISO to recover its operational costs and the amount is determined annually through a budget process, which includes a robust external stakeholder review process. For these ISOs, the budgets should be filed with the FERC after the approval of the Board of Directors.[43] Hawaii does not fall under FERC jurisdiction so the IGO would report to the Commission, similar to that in Texas where ERCOT reports to the PUCT.

5.2.1 Financial requirements for implementation

Implementation costs of an IGO model vary, driven by a number of factors including the size of the market, market design, complexity of the auction and settlement processes, and extent of stakeholder and outreach levels. Each of these factors is a significant hurdle that must be overcome by any jurisdiction and carries a risk for cost overruns if not carefully managed and

[41] FERC. *Order No. 2000 – Regional Transmission Organizations.* Docket No. RM99-2-000. December 20, 1999. Page 323.

[42] Ibid.

[43] Ibid.

designed. Annual operating budgets vary across regional ISOs in North America. Samples of 2017 costs—showing a range of $2.1/kW in Texas to $5.2/kW in Ontario—are in Figure 3. The Project Team has assessed the key cost factors for implementation of the IGO model based on regional ISO budgets.

Figure 3. Regional ISO Budgets

Market	Annual ISO Budget ($ '000)	Installed Capacity (MW)	Net Generation (GWh)	$ per kW	$ per kWh
California (CAISO)	$195,300	70,848	146,597	$2.76	$0.0013
New York (NYISO)	$148,200	44,570	116,082	$3.33	$0.0013
Ontario (IESO)	$191,400	36,945	144,300	$5.18	$0.0013
Texas (ERCOT)	$223,100	107,535	323,655	$2.07	$0.0007
Average				$3.33	$0.0012

Source: SNL; ISO Annual Reports and Business Plans

The Project Team notes that ERCOT, unlike the other markets, has a relatively simpler market structure (as it operates an energy-only market), as opposed to an administratively complex energy and capacity market as in California, New York, and Ontario. California and Ontario have centralized structures as well as wholesale markets, thereby, further increasing the complexity of those markets.

5.2.1.1 Market size and lack of interconnection

Hawaii's installed capacity of 3,427 MW is distributed across the different counties and islands, from 2,329 MW in Honolulu County (comprising the largest share) and 200 MW in Kauai County (the smallest).[44] The lack of an interconnection among the islands suggests that a wholesale market would be required in each of the islands and although the existing dispatch, monitoring, and control equipment (that manage the transmission/distribution system) already exists, market monitoring and settlement technology would be needed in each island to ensure data transparency.

Across North America, the smallest wholesale market is the one operated by the Alberta Electricity System Operator, with an installed capacity of approximately 16 GW. Within the context of islanded markets, in Mexico, the power grid of the state of Baja California is islanded from the rest of the Mexican grid. As a result, three markets operate in parallel, i.e., the National Interconnected System (*Sistema Interconectado Nacional*), Baja California Interconnected System, and Baja California Sur Electric System.[45] Similarly, in the Philippines—a country with more than 7,000 islands (which are mostly not interconnected)—there are three (3) wholesale markets

---

[44] HECO Companies' Power Supply Improvement Plans; KIUC website

[45] SENER; IEA, *Mexico Energy Outlook.* World Energy Outlook 2016

namely Luzon, Visayas, and Mindanao.[46] Effectively, there is one market operator overseeing three separate systems – the Luzon and Visayas grids have a high voltage direct current connection with limited inter-system trade. The Visayas system does include interconnections between some large islands, each with several hundred MWs of installed capacity. However, having one system operator across multiple systems helps to standardize market rules and achieve cost efficiencies. The Mindanao wholesale electricity market will also be under the same market operator once it becomes operational. Therefore, factors such as market size and lack of interconnection are important drivers of cost.

5.2.1.2 Market design and implementation

The costs of implementation of an IGO are not insignificant and include costs of acquisition of the utility's existing control room infrastructure, i.e., specific software and equipment used by the current utilities for system planning, dispatch, and day-to-day operations. Setting up an IGO also includes procurement of software and IT hardware and recruitment of personnel from the utility and outside, to name a few. In its assessment of start-up and operating costs for ISOs in the US upon inception by the end of 2004, FERC staff placed them between $50 and $70 million.[47] FERC's estimates involved a survey of four ISOs, namely, Midcontinent ISO, ERCOT, PJM, and Southwest Power Pool. A review of the cost categories suggests that not all costs—such as software procurement and IT system development—may need to be duplicated for a Hawaii-wide adoption of the ISO model. Others such as personnel recruitment and building costs would need to be replicated in each market.

5.2.2 Financial impact on the Commission, utilities, and ratepayers

From the perspective of ratepayers, the setup and operating costs of an IGO would fall on ratepayers. However, this would be balanced by likely market efficiencies from competition, that would ultimately benefiting customers.

The implementation of the IGO would likely result to additional costs for the Commission. More specifically, the Commission would need to create mechanisms for market monitoring, competition assessment, and dispute resolution, whether these would be assessed by the IGO, Commission itself or delegated to an independent third party.

The utilities would not be impacted financially by the implementation of an IGO model. Ultimately, the financial impact of the transition to an IGO regulatory model depends on the design of the transition and commitment of regulators toward full implementation. Regulatory uncertainty could be financially costly for both the utility and ratepayers and has been

---

[46] Although the Mindanao wholesale market was originally scheduled to be launched in June 2017, the commercial operations have been pushed back to the first half of 2019, according to a press release on October 2nd, 2018 by the Philippines Department of Energy.

[47] FERC Staff. *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization*. Docket No. PL04-16-000. October 2004.

demonstrated to lead to adverse outcomes for all parties.[48] The textbox below shares the experience of New Brunswick as it dealt with challenges and barriers in the implementation of the ISO model.

New Brunswick: A Cautionary Tale

New Brunswick's electricity market is serviced almost entirely by New Brunswick Power Corporation ("NB Power"), a vertically integrated and provincially-owned Crown utility company responsible for most of the province's generation, transmission, and distribution. While NB Power has mostly served as a bundled utility since its inception, the Government of New Brunswick has also experimented with competitive electricity markets, beginning by unbundling the company's generation, transmission, and distribution assets in 2004.

In 2004, New Brunswick implemented the *Electricity Act*, which was passed one year earlier, whereby NB Power was divided into five separate companies, providing a legal and financial structure to support a decentralized organization. The benefits envisioned before restructuring did not materialize the way that the government intended. From 2003 to 2009, NB Power had the second-fastest increase in industrial electricity costs of any province in Canada, owing to various internal and external factors, such as rising fuel and debt servicing costs.

In October 2013, after nine years of limited competition in the generation sector, the Government of New Brunswick decided to amalgamate NB Power back into a single Crown company that services most of New Brunswick's generation, transmission, and distribution needs. The decision to revert to vertical integration was mainly because a competitive electricity market failed to develop, contrary to what policy makers had anticipated.

In October 2011, the government released a 10-year "Energy Blueprint" with the goal of reintegrating NB Power into a fully regulated and vertically integrated utility, citing the failure of a competitive market to develop and the need for cost reductions as the leading causes. In October 2013, the *Electricity Act* was amended, and all the companies separated in 2004 became amalgamated in NB Power once again. NB Power's de facto dominance of the separate businesses quickly became a significant barrier to entry for new market participants in terms of costs and grid access.

New Brunswick's experience from 2004 to 2013 illustrated potential challenges and barriers that could arise from the implementation of the ISO model. Furthermore, the *de facto* structure of the market hardly changed because NB Power remained as the holding company. Potential competitors had trouble gaining access to transmission and ancillary services, which are required to offer a complete supply package.

Sources: New Brunswick Department of Energy. *The New Brunswick Energy Blueprint*. New Brunswick: October 2011; Adams, Thomas. Borealis Energy Research Association. "New Brunswick's Power Failure: Choosing a Competitive Alternative." *Atlantic Institute for Market Studies*. October 2006.

---

[48] Joskow, P. *Lessons Learned from Electricity Market Liberalization.* The Energy Journal. 2008

5.3 Legal feasibility

This section assesses the capacity of the current legal and regulatory framework, significant legal and regulatory changes necessary, as well as any additional legal considerations in implementing the IGO regulatory model. Overall, there are at least two significant elements that must be considered in analyzing the legal feasibility of the IGO model: (i) functional unbundling of transmission service and establishment of open access transmission tariffs and related administrative and operational requirements for the existing utilities; and (ii) establishment, funding, and empowerment of an IGO entity.

5.3.1 Existing legal framework for the regulatory model

Currently, there is no existing legal framework for the IGO regulatory model in Hawaii. However, as discussed above, Hawaii law does provide broad supervisory and investigative powers. These powers have been used by the PUC to initiate proceedings regarding related issues including the need for an ISO-like entity as part of industry restructuring and intergovernmental wheeling. However, after several years of a lack of consensus among stakeholders on any significant issue raised in the docket, the PUC has not taken any action on these issues.[49] Moreover, some of the reliability functions that are expected to be performed by the IGO entity under the IGO regulatory model are governed by the HERA Law, as discussed above.[50]

5.3.2 PUC authority under current legal and regulatory framework

Hawaii's current legal and regulatory framework has no expressed authorization for the PUC to implement the IGO regulatory model. Depending on the specific structure and functions of the IGO entity, the PUC is likely authorized to implement some components of the IGO regulatory model through one or more administrative proceedings under its current general supervision, investigation, and ratemaking authority (through HRS Chapter 269). However, legislation may be needed to clarify the PUC's authority over the IGO entity and, as a practical matter, to incentivize the PUC to proceed with this particular course.

With respect to the functional unbundling of transmission service and the establishment of open access transmission tariffs and related administrative and operational requirements for the existing utilities, HRS Chapter 269 grants the PUC broad supervisory and investigatory powers over public utilities, administrative rulemaking authority pursuant to HRS Chapter 91, and authority over utility ratemaking. This which would likely enable the PUC to require the utilities to establish open access transmission tariffs, adjust accounting procedures, and enact and enforce

[49] PUC. Docket No. 96-0493, Order No. 15285, issued December 30, 1996 (electric restructuring for retail competition); PUC. Docket No. 96-0493, Decision & Order No. 20584, issued October 21, 2003 (closing the docket without taking action); PUC. Docket No. 2007-0176, Order No. 23530, issued June 29, 2007 (intergovernmental wheeling).

[50] HRS Chapter 269, Part IX. Electric Reliability.

other administrative and operational requirements required to implement the functional unbundling component of the IGO regulatory model.[51]

The PUC's general supervisory authority extends to the supervision of "public utilities" (as the term is defined under HRS § 269-1) as well as certain matters where non-utilities interact with public utilities.[52] The specific functions that the IGO entity performs, how it is constituted, and specific customers it serves would determine whether it may be subject to the PUC's broad direct supervisory authority as a public utility or not.[53] As such, the PUC may or may not have broad direct supervisory authority (including over the ability to establish rates for its services and the rule with which it must comply) over the IGO entity as a public utility. Moreover, under the HERA Law, the PUC is authorized to delegate certain functions to a third party, including the function of acting as HERA. [54] However, as state earlier, the PUC is not permitted to contract a public utility that can serve as HERA.[55] As such, under the current Hawaii law, it may be possible for an IGO entity to function as HERA as long as it is not a public utility under HRS Chapter 269. If an ISO or IGO would otherwise be deemed to be a public utility under HRS Chapter 269, legislation would be required to add an exemption for IGOs in the definition of public utility.[56]

5.3.3 Statutory changes or laws required for implementation

At the minimum, legislation should be introduced to clarify the PUC's oversight of the IGO entity and permit any funding mechanism. This could include clarifying the PUC's authority to regulate the IGO entity as a public utility and modifying the HERA Law to permit a public utility to serve as an IGO that would perform the HERA role. Alternatively, this could be achieved by excluding the IGO entity from the definition of public utility (similar to that for independent organizations

[51] HRS §§ 269-6, 269-7.

[52] HRS §§ 269-6(a), 269-7, 269-15.

[53] As defined under HRS § 269-1, the term "public utility" includes:

> every person who may own, control, operate, or manage as owner, lessee, trustee, receiver, or otherwise, whether under a franchise, charter, license, articles of association, or otherwise, any plant or equipment, or any part thereof, <u>directly or indirectly for public use</u> . . . for the production, conveyance, transmission, delivery, or furnishing of . . . power [.]

HRS § 269-1 (emphasis added). Under Hawaii law, a person that does not "hold himself out, expressly or impliedly, as engaged in the business of supplying his product or service to the public, as a class, or to any limited portion of it, as contradistinguished from holding himself out as serving or ready to serve only particular individuals" is not a "public utility". *Application of Wind Power Pac. Inv'rs-III*, 686 P.2d 831, 834 (Haw. 1984).

[54] HRS § 269-147(a).

[55] HRS § 269-147.

[56] See, HRS § 269-1.

as used by ERCOT)[57] and drafting a new statutory framework or modifications (e.g., that provide for oversight and funding) to the existing HERA Law.

Legislation is not required to initiate the functional unbundling of transmission or establishment of open access non-discriminatory transmission tariffs. However, a law that mandates the functional unbundling of transmission and establishment of an IGO entity may increase certainty about the intended outcome of the associated PUC proceedings, reduce objections to a PUC initiated process, and ensure follow through by the PUC, which may prioritize its resources toward issues and objectives that are required by the legislature.

5.3.4 Administrative actions required by the PUC

Significant regulatory changes are necessary to implement the IGO model. The precise nature of the changes would depend on whether the IGO entity is treated as a public utility in the way FERC regulates ISOs (i.e., as a unique independent organization similar to how PUCT currently regulates ERCOT) or as a PUC contractor consistent with the current HERA Law.[58]

Whether as a result of legislative requirements or the PUC's own initiative, the PUC would need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings. These include proceedings to: (i) develop open access non-discriminatory transmission tariffs for the incumbent utilities; (ii) determine administrative and operational requirements, such as a transparent data access system, for the IGO to function; (iii) issue a certificate of public convenience and necessity to the IGO entity, if regulated as a public utility; (iv) establish an IGO tariff, if regulated as a public utility; (v) provide for the division of roles and responsibilities between the ISO and the incumbent utility; and (vi) implement statutory requirements for fees and governance, if applicable.

5.3.5 Additional legal issues

Currently, in each island, Hawaii's electric utilities have various existing PUC-approved PPAs with various IPPs. To the extent that the IGO entity functions to procure and dispatch generation resources, the existing PPAs must be dealt with in a way that does not violate the Contract Clause of the United States Constitution (the "Contracts Clause").[59] Any laws or regulations that

---

[57] *See* Tex. Util. Code Ann. § 39.151.

[58] FERC generally regulates ISOs and RTOs as public utilities and they are funded pursuant to FERC approved tariffs. GAO, Electricity Restructuring, GAO-08-987, (Sept. 2008) ("Because RTOs charge for the use of transmission lines, for certain wholesale sales of electricity, and to recover their own expenses, they are subject to FERC oversight and regulation."), accessed at https://www.ferc.gov/industries/electric/indus-act/rto/gao-report.pdf. In contrast, ERCOT is regulated by PUCT as an "independent organization" under separate statutory authority and is funded pursuant to a PUCT approved budget. Tex. Util. Code Ann. § 39.151. Under the current HERA law, the HERA, if constituted, is a contractor. *See* HRS § 269-147.

[59] U.S. Const., art. I, § 10, cl. 1.

substantially impair an existing contractual relationship may be found unconstitutional if they are not drawn reasonably and narrowly to serve a significant and legitimate public purpose.[60]

5.4 Conclusion

The IGO model has demonstrable technical, financial, and legal feasibility challenges—with the need for multiple new entities in each county and acquisition of dispatch and control software, along with market design and implementation, among the key risks. The benefits of open access and lack of interconnection bias are ideal for achieving state energy goals and existing personnel and infrastructure may lower start-up costs. That being said, there are considerable risks to the implementation of this model with respect to its technical, financial, and legal feasibility, (Figure 4). Therefore, this model ranks under *medium risk* in its overall feasibility.

Figure 4. IGO Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+/-) Depends on scope of mandate of IGO
	Compliance with service standards	(+) IGO would be responsible for short term reliability
	Achievement of State clean energy goals	(+/-) Open access and lack of interconnection bias offset by lack of addressing incentives for DERS
Financial Feasibility	Implementation requirements	(+/-) Depends on the transition process
	Impact on ratepayers	(-) Potential for stranded costs falling on customers
		(-) Setup and operating costs of implementation
	Impact on utilities	(+/-) Depends on whether utilities are able to capture market efficiencies
Legal Feasibility	Existence of supporting legal framework	(-) Not currently an existing legal framework for the IGO regulatory model in Hawaii
	Governance requirements	(-) PUC will need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings
	Additional legal factors	(-) PUC-approved PPAs will need to be dealt with appropriately

Source: LEI analysis

[60] *Applications of Herrick*, 922 P.2d 942, 954 (Haw. 1996).

6 Distribution-focused regulatory model

The distribution-focused regulatory or Distributed System Platform Provider ("DSPP") model envisions that the utility serves as the DSPP. Currently, New York is the only state that has concrete plans of moving forward to a distribution-focused regulatory model. New York's Reforming the Energy Vision ("REV") model, which aims to increase the use of clean energy and increase customer participation in the electricity sector, has energy goals similar to Hawaii's. Under the DSPP model, the distribution system would be owned and operated by the utilities. Similar to NY's REV, the Project Team anticipates that the DSPP would be responsible for designing and planning the distribution system, which would help integrate DERs.

6.1 Technical feasibility

6.1.1 Requirements for establishment

The transition to DSPP could be lengthy and complex. More specifically, moving to a DSPP model necessitates piloting new and different ways to operate the electricity system and work with third-party DER providers. It also requires having a different business/ownership model for the utility as highlighted in Task 1.

As discussed in Task 2.1.1, Hawaii has high levels of DER adoption and state policy promotion but lagging in infrastructure investment. This is Stage 2 of the DER adoption curve. To be able to move to the DSPP model, Stage 2 requires enhanced functional capabilities for reliable distribution operations[61], thereby necessitating changes in grid planning and operations in order to accommodate DERs at their levels as well as provide system-wide benefits.

The HECO Companies launched the Grid Modernization Strategy, which would ultimately aid in infrastructure improvements. In combination with the implementation of the proposed DSPP model, this strategy would likely propel the State to move forward toward Stage 3 (Distributed Markets) of the DER adoption curve (possibly closer to California's stage). The highlights of the first phase of the strategy include deployment of advanced meters, launch of a meter data management system, and implementation of a telecommunications network. The first phase will be implemented from 2019 to 2023.[62]

To implement the DSPP model, the Hawaii PUC would first need to initiate discussions (particularly in defining the DSPP) amongst relevant stakeholders. This step may be a lengthy process as seen in New York's REV model (Task 2.1.1 and Task 2.2.2), which lasted approximately 11 months. In doing so, the PUC must also establish clear guidelines pertaining to the roles and responsibilities of the DSPP, based on the stakeholdering process and regulatory structure. For instance, as recommended in Task 2.2.2, the PUC may need to restrict utilities from owning local

---

[61] Martini, P. and Kristov, L. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation, and Oversight.* Lawrence Berkeley National Laboratory. Report No. 2. October 2015.

[62] "Hawaiian Electric Companies take steps to implement first phase of grid modernization strategy." *Maui Electric Hawaii Electric Light.* June 21, 2018. Web. July 30, 2018. <https://www.hawaiianelectric.com/hawaiian-electric-companies-take-steps-to-implement-first-phase-of-grid-modernization-strategy>

power generation to ensure fair competition. The Hawaii PUC would then order the utilities to take the new role of the DSPP on. The Hawaii PUC should also review the existing regulatory model and ratemaking approach and revise items so that they would be in line with the utilities' new role. Furthermore, the PUC must then develop a distribution use of system charge that would facilitate wheeling within the distribution system.

6.1.2 Impact on the roles and responsibilities of the Commission

To assess any additional infrastructure or capabilities the DSPP model may require of the Commission, the Commission must first consider the status of DER adoption in the State of Hawaii, how prepared utilities are in integrating DERs, and how the existing rate design affects DERs.[63] As mentioned, Hawaii falls under Stage 2 of the DER adoption curve, signifying that Hawaii currently has moderate to high levels of DER penetration in the State. Behind-the-meter generation resources or distributed generation in Hawaii predominantly consist of rooftop solar photovoltaic ("PV") panels. In combination with the Grid Modernization Strategy, the DSPP model would support the State's move towards Stage 3 by providing a platform for increased penetration of renewables and DERs. This growing presence of DERs would call for the regulator's focus on the system at a distribution level as this is where DERs predominantly affect the system. As such, under the distribution-focused regulatory model, the Commission may require increased "*visibility into and oversight of the planning of a utility's circuits and broader distribution system.*"[64]

Under the DSPP model, the PUC must ensure fair competition in the distribution marketplace along its current responsibilities (detailed in Task 2.1.2). The Commission would monitor open access and encourage the utilities to provide a platform for third-party DER providers—thereby creating value for both customers and the grid. This could be achieved either through explicit orders or incentives within existing ratemaking.

To accommodate the aforementioned additional capabilities, thus, achieve increased visibility and oversight of the distribution system, the Commission would require access to certain data (e.g., those essential in the analysis of the grid design and optimization as well as planned investments). This data includes, but is not limited to, grid needs by technical characteristics (e.g., capacity, reactive power, voltage, resiliency, spinning/non-spinning reserves etc.), geographic location, and installed DER capacity and forecasted growth by circuit.[65] The provision of this data may necessitate advanced technologies that could support the Commission in making informed decisions regarding rate design and DER compensation, responding to any changes in the pace of DER adoption, and identifying the level of adoption of DERs across a jurisdiction.

---

[63] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016.

[64] Ibid, page 146.

[65] Ibid, page 148.

Overall, the integration of DERs, particularly when exporting electricity to the grid, may introduce system planning complexities for the utility. The utility would remain responsible for maintaining and upgrading the system for reliability purposes, thus, this new regulatory model may necessitate new investments to allow two-way electricity flow.[66] Put differently, utilities may need to upgrade distribution equipment if circuits export to the grid and act as step-up facilities.[67]

Moreover, to further facilitate the adoption levels of DERs, utilities may opt for additional infrastructure and technologies that can help maintain reliability within the distribution grid as well as enhance resilience. As per the National Association of Regulatory Utility Commissioners ("NARUC"), utilities may consider two options: (i) Advanced Distribution Management System; ("ADMS") and (ii) Distributed Energy Resource Management Systems ("DERMS").[68] The implementation of ADMS would enable the distribution utility to examine real-time conditions readily across its service territory through increased communication and visibility of the distribution grid. More specifically, this tool would provide utilities with functions including, but not limited to: (i) fault location, isolation, and service restoration; (ii) conservation voltage reduction; and (iii) volt/VAR optimization.[69] DERMS, on the other hand, would enhance utilities' ability further by allowing utilities to "*dispatch resources, both on the utility side and the customer side; forecast supply and demand conditions up to 24-48 hours in advance; better integrate AMI data with other utility systems, such as ADMS, outage management, and weather systems; and communicate with third-party/aggregator systems.*"[70] DERMS could be used in islanding and microgrids.[71] All in all, technology solutions such as ADMS and DERMS would aid distribution utilities in planning and operating DERs as they continue to be adopted across their respective service territories, ultimately aiding the Commission in decisions regarding rate design, DER compensation, and identifying cross-jurisdictional DER adoption levels.

Moreover, in order to move closer towards Stage 3 of DER adoption (which results from high levels of DER adoption and policy decisions to create distribution-level energy markets for multi-party transactions), the Commission would also need to implement changes that enable retail energy transactions, including those "*within a local distribution area defined by a single [transmission-*

---

[66] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 16.

[67] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015

[68] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 52.

[69] Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems. Department of Energy*, Washington, D.C. February 2015. Web. Access date: June 6, 2018. <ttps://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf>

[70] Jeff St. John. *Inside SDG&E's Plan to Optimize the Distributed Grid of the Future*. Greentech Media. May 16, 2014. <http://www.greentechmedia.com/articles/read/sdge-and-spirae-break-new-ground-on-the-grid-edge>.

[71] National Association of Regulatory Utility Commissioners. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation.* November 2016. Page 53.

distribution] interface substation, thus not relying on transmission service."[72] In other words, the Commission would need to establish a peer-to-peer ("P2P") energy transaction platform as a "*next-generation energy management mechanism*", thereby allowing prosumers of the network to trade with one another as well as the grid also.[73] Similar to online platforms for retail goods, the P2P energy trading platform would serve as an online marketplace for electricity products and services. While such a platform has been adopted for microgrid systems[74], it is yet to be realized in other markets.

Finally, the success of this regulatory model hinges on the distribution utilities' capabilities, including on advanced grid platform technologies and operating procedures such as for cases when they need to call upon the DERs (as per need in real time) and in monitoring the latter's visibility so their performance may be tracked. It is also upon the utility to "*develop methods to identify needs of the system by location, determine hosting capacity, assess potential benefits of DERs on a particular feeder and distribute DERs optimally*" within the distribution service area.[75]

6.1.3 Impact on the roles and responsibilities of utilities

If utilities would take on the role of the DSPP, the PUC may restrict them from owning local power generation to avoid the occurrence of vertical market power. This challenge currently exists in Hawaii because utilities own and operate generation, transmission, and distribution. As such, with DSPPs owning DERs, the vertical market power may would be exacerbated even further.

6.1.4 Compliance with reliability, adequacy, and quality of service standards

The DSPP model would be able to ensure that influx of DERs may not pose a significant threat to the reliability of the power system. As discussed in Section 6.1.2, the DSPP model would be able to ensure that there is balance between reliability and potential increase of DERs in the system (through careful planning) as well as additional infrastructure and technologies, which may be adopted by utilities—all of these would likely contribute to the increased and improved visibility and oversight of the distribution system by the PUC.

---

[72] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015

[73] IEEE. *Transforming Energy Networks via Peer to Peer Energy Trading: Potential of Game Theoretic Approaches.* March 19, 2018. <https://arxiv.org/pdf/1804.00962.pdf>

[74] As an example, LO3 Energy and Siemens created a pilot microgrid in Brooklyn, New York. The system allows solar panel owners to trade energy with their neighbors using blockchain technology. (Source: "The Brooklyn microgrid: blockchain-enabled community power". *Power Technology.* April 11, 2017. Web. July 16, 2018. <https://www.power-technology.com/features/featurethe-brooklyn-microgrid-blockchain-enabled-community-power-5783564/>

[75] DeMartini & Kristov. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight.* Lawrence Berkeley National Lab. October 2015.

6.1.5 Ability to achieve State energy goals

A DSSP model would be able to support the growth of DERs by incorporating them in distribution-level planning, allowing them to provide grid services, and facilitating direct transactions with other customers.

The facilitation of DERs through the distribution-focused regulatory model would aid the State in diversifying its energy mix as well as in its pursuit of "*de-carbonization of electricity supply.*"[76] Moreover, DER products available in the market may optimize environmental benefits by way of, for instance, the incorporation of a range of electric vehicle purchase and charging incentives, including lifecycle assessment of emissions.

Moreover, the State of Hawaii aims to have an efficient marketplace that is beneficial to both producers and consumers.[77] As such, the DSPP model could lead to lower costs to consumers as they shift consumption away from the grid during peak hours through DERs as well as impact of efficiency gains from competition, which will likely result from behind-the-meter markets. Furthermore, the increased integration of DERs would likely reduce distribution grid costs, thereby further maximizing consumer cost savings.

6.2 Financial feasibility

6.2.1 Financial requirements for implementation

As discussed in Task 2.1.1, the DSPP model has not yet been implemented to completion in any jurisdiction. Therefore, only high-level estimates on the financial requirements of its implementation can be made and for the purposes of this analysis, we will focus on the financial requirements for open access.

The grid platform technologies that would help facilitate the transition of a utility into becoming a DSPP would require significant investment, which could ultimately be recovered from ratepayers. Section 6.1.2 identified some of the infrastructure needs toward transition to the DSPP.

In addition, this model would require significant outreach and customer education efforts as well as careful market design to promote competitive market participation. The example of New York is prescriptive in illustrating the financial requirements of this model. Currently, the implementation of the REV model has taken place through a step-wise manner, with more focused and targeted milestones in each step. To facilitate the transition, the utilities have been required to file Distributed System Implementation Plans ("DSIPs"), which outline near- to

---

[76] SolarCity Grid Engineering. *A Pathway to the Distributed Grid: Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value.* White paper. February 2016.

[77] Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf

medium-term investment plans that they need to execute in order to facilitate greater DER penetration in their networks.

In one example, ConEdison indicated in its DSIP that it will spend $214 million in capital investments to facilitate system expansion for DERs—a plan that includes a roadmap to integrate 800 MW of DERs by 2020.[78] ConEdison's DSIP also provides a hosting capacity map of its existing network of stakeholders; a step that may be considered as a foundation of its role as a DSPP.[79] As discussed in Task 1.1.4, estimates of the capital expenditure ("capex") costs in establishing this model ranged from between about $20 million to more than $250 million over five years, based in the experiences of New York.[80] Estimating the costs for Hawaii's utilities would require a thorough study of the existing infrastructure of the utilities and enabling technologies specific to each county along with assumptions of the distribution-focused regulatory framework.

6.2.2 Financial impact on the Commission, utilities, and ratepayers

As discussed in Section 6.1.2, additional infrastructure and technologies are needed to be able to implement the DSPP model. The Project Team assumes that these infrastructure and technologies would be included under the rate base of the utilities, thus, borne by the ratepayers.

Under the DSSP model, ratemaking would need to be modified, with different degrees of impact on the utility and ratepayers. The cost-of-service ("COS") approach would still be used in combination with market-based platform earnings and outcome-based earning opportunities (similar to what New York's REV is proposing).[81] More specifically, the REV provides a framework that illustrates how utility earnings could be achieved under the distribution-focused model, for example, through: (1) traditional COS earnings; (2) earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; (3) earnings from market-facing platform activities; and (4) transitional outcome-based performance measures.[82] . This conceptual framework of utility earning mechanisms from a DSPP model is applicable to the Hawaii context as it illustrates the potential impact of the financial framework to the utility. For Hawaii, this presents a pathway of options for how a DSPP model may restructure the financial paradigm of the sector. A practical example of how this framework could

---

[78] Con Edison. *Distributed System Implementation Plan (DSIP).* June 30, 2016.

[79] Ibid.

[80] In Task 1.1.4, the Project Team assessed the future needs for generation, transmission, and distribution infrastructure within each county, and within the context of each ownership model. A more detailed discussion of the needs that would arise from the move to an IDER ownership model is undertaken in this memo.

[81] NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order). Page 2.

[82] Ibid, Page 2.

be implemented is discussed in the textbox below, where a case example of a DSPP project in New York is discussed.

Potential Utility Earning Mechanisms from a DSPP Model Under REV

In their traditional COS earnings, the utilities will earn a return on their rate base following their existing ratemaking schedule and procedures. Under the second track, the utilities' earnings are tied to achievement of alternatives that reduce capital spending. The Brooklyn Queens Demand Management case study is a prescriptive example, whereby the regulator recognized the utility's forfeiture of capital investment and authorized a return on total program expenditures as well as offered performance incentives tied to achievement of goals that will lead to more customer savings.[1]

Under the third track, the utility will see potential earnings from market-facing platform activities particularly as designed in the value stack approach of valuing DER solutions. The New York Department of Public Service staff's assessment of this track of earnings envisions "Platform Service Revenues" ("PSRs") for the utility. PSRs will be earned by utilities through their provision of services (to market participants) as DSPPs. Examples of some of these revenues include customer origination via the online portal, data analysis, co-branding, transaction and/or platform access fees, optimization or scheduling services that add value to DER, advertising, energy services financing, engineering services for microgrids, and enhanced power quality services. Furthermore, it is envisioned that through this revenue stream, increased PSRs would encourage utilities to support access to their systems by DER providers and offset required base revenues derived from ratepayers.[1]

The fourth track of potential earnings are utility incentives that are tied to near-term measures undertaken by the utility to create customer savings and develop market-enabling tools. The incentive mechanisms are designed to align "*the utilities financial interests with the regulator's REV objectives*" with the goal that the incentives play a transitional role until other forms of market-based revenues are available at scale. Incentives recommended by the New York regulator relate to peak efficiency (aimed at near-term system savings and development of DERs), customer engagement (aimed at educating and engaging customers and providing access to data), affordability (aimed at low-income customer participation in DERs), and interconnection (aimed at increasing speed and affordability of interconnecting DERs).[1] Importantly, these incentives vary in their symmetry i.e., positive (no penalty if targets are not met), negative (no reward if targets are met), and bi-directional.

Source: NY PSC. *Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision,* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016)

Implementing a DSPP solution in New York State

Among the demonstration projects filed under the REV Distributed System Platform ("DSP") project was a solution involving Niagara Mohawk Power Corporation, a subsidiary of National Grid USA, the Buffalo Niagara Medical Campus Inc. ("BNMC"), and Opus One Solutions ("Opus One"). BNMC is a network of 13 institutions and nearly 100 public and private companies while Opus One is a software engineering company offering distribution grid solutions for the project. This project seeks to test a centralized DSP that would communicate with network-connected points of control ("POC") associated with BNMC's network of DERs, which are described further below.

National Grid's Elm Street substation provides power to the BNMC through local distribution stations (via underground 23 kV circuits) and is the central distribution point for most of the BNMC buildings. BNMC's current DER capacity is over 34 MW with about 28 MW consisting of diesel generators and approximately 1 MW from demand response. Furthermore, BNMC is currently evaluating increasing its DER capacity by adding 19 MW of natural gas generation, 1 MW of solar PV, and 150 kW of battery storage.

The proposed DSP would be designed to communicate system needs of the Elm Street substation and local feeders and send dynamic pricing signals to the POCs through the Opus One-designed platform. The control points would then communicate with the DSP as to the availability of BNMC's DERs that could respond to electric system needs and, crucially, their willingness-to-accept pricing signals. Within the BNMC "market", the project seeks to evaluate at what price points the BNMC DERs are willing to provide system services as well as what level of revenues would motivate further DER development.

Noteworthy is the cost estimates provided by National Grid for the project as well as the proposed revenue models for the utility. The project's total cost has been estimated at $6.8 million with $4 million attributed to software development capital expenditure and annual operating expenses of $230,000. By way of revenue models, National Grid has proposed a number of options to leverage the platform once development is complete. The first is provision of one-time data as a service about distribution optimization opportunities to help BNMC members make decisions on their potential investments in DER assets. The second is provision of access to the DSP through a monthly or annual fee or a license or contractual agreement with the ownership party.

Sources: New York Department of Public Service. *Staff Proposal: Distributed System Implementation Plan Guidance.* Case 14-M-0101. October 2015; National Grid. *Proposed REV Demonstration Project: Distributed System Platform*. June 2016.

6.3 Legal feasibility

Significant elements must be considered in analyzing the legal feasibility of the DSPP model. The DSPP model requires the following: (i) functional unbundling of distribution service and establishment of open access distribution tariffs and related obligations for the existing utilities; (ii) establishment of platform and outcome-based revenue mechanisms; and (iii) establishment of standards for utility participation in the DER marketplace. The model may also require the incumbent utilities' divesture of distribution utility assets and functions.

6.3.1 Existing legal framework for the regulatory model

There is currently no existing legal framework that expressly governs the regulatory model in Hawaii. However, as discussed above, Hawaii law does provide broad supervisory and investigative powers through HRS Chapter 269, which allow the PUC to develop policies, rules, standards, practices, and other requirements applicable to public utilities.

6.3.2 PUC authority under current legal and regulatory framework

Hawaii's current legal and regulatory framework has no expressed authorization for the PUC to implement the DSSP regulatory model. Nevertheless, the PUC is likely authorized to implement some components of this models through one or more administrative proceedings under its current general supervision, investigation, and ratemaking authority through HRS Chapter 269. However, while the DSPP (through its ownership and operation of facilities) may be regulated by the PUC as a public utility, additional legislation may be needed to allow the DSPP to take certain reliability oversight roles on.

When it comes to the functional unbundling (discussed in Section 5.3) of distribution service required for the DSPP regulatory model, HRS Chapter 269 grants the PUC broad supervisory and investigatory powers over public utilities, administrative rulemaking authority (pursuant to HRS Chapter 91), and authority over utility ratemaking.[83] This would likely enable the PUC to require the utilities to establish open access distribution tariffs, establish platform and outcome-based revenue mechanisms, adjust accounting procedures, and enact and enforce other administrative and operational requirements as required in implementing the functional unbundling of distribution service and establishment of open access distribution tariffs and related administrative and operational requirements. Moreover, this would allow the PUC to establish standards for third-party participation in the DER marketplace under the DSPP model.

The PUC's general supervisory authority extends to the supervision of "public utilities" as the term is defined under HRS § 269-1 as well as certain matters where non-utilities interact with public utilities.[84] Under the DSPP model, the PUC would almost certainly have broad direct supervisory authority over a DSPP as a public utility because the latter owns and operates distribution facilities, which interconnect with the general public.

---

[83] *See* HRS §§ 269-6, 269-7.

[84] *See* HRS §§ 269-6(a), 269-7, 269-15.

6.3.3 Statutory changes or laws required for implementation

When it comes to the functional unbundling of transmission (discussed in Section 5.3), no legislation is required to initiate the functional unbundling of distribution services, establishment of platform or outcome-based revenue mechanisms, or setting of open access non-discriminatory distribution tariffs.

6.3.4 Administrative actions required by the PUC

Significant regulatory changes are necessary to implement the DSSP model. Whether as a result of legislative requirements or the PUC's own initiative, the PUC would need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings. These may include proceedings to (i) develop open access non-discriminatory distribution tariffs for the incumbent utilities, (ii) establish platform and outcome-based revenue mechanisms, (iii) issue a certificate of public convenience and necessity to the DSPP entity, (iv) implement statutory requirements for fees and governance, if applicable, and (v) approve utility asset divestiture, if needed for the DSPP model.

6.3.5 Additional legal issues

As discussed in Section 5.3.5, any law or regulation that substantially impairs an existing contractual relationship may be found unconstitutional if it is not drawn reasonably and narrowly to serve a significant and legitimate public purpose.[85] Where a new distribution utility assumes a role that impacts contractual arrangements for grid access (e.g., for customer sited DER or for IPPs), existing interconnection agreements and related arrangements must be dealt with in a way that does not violate the Contract Clause.

6.4 Conclusion

The DSPP model has demonstrable technical implementation, financial feasibility, and legal feasibility risks particularly given the lack of global best practices to draw examples from. The roles and responsibilities of both the Commission and the utilities would change significantly as the regulator must design and implement a new ratemaking paradigm and the utilities transition to a power system that promotes greater DER penetration and open access of the distribution grid. While it presents potential benefits, there is significant implementation risk. As a result, the Project Team believes that the DSPP model has a high level of feasibility risk (Figure 5).

---

[85] *Applications of Herrick*, 922 P.2d 942, 954 (Haw. 1996).

Figure 5. DSPP Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	(+) Significant changes in roles for both commission and utilities, requiring careful transition
	Compliance with service standards	(+/-) Depends on enforcement of standards at various scales of DER penetration
	Achievement of State clean energy goals	(+) Increased DER growth and market participation from consumers
Financial Feasibility	Implementation requirements	(+/-) Requires careful market design
	Impact on ratepayers	(+/-) Increased benefits from consumer participation and DERs possible
	Impact on utilities	(+/-) Depends on effectiveness of transition to DER-focused system
Legal Feasibility	Existence of supporting legal framework	(-) Not currently an existing legal framework for this regulatory model in Hawaii
	Governance requirements	(-) PUC will need to undertake at least one or more investigative, ratemaking, and/or rulemaking proceedings
	Additional legal factors	(-) PUC-approved PPAs will need to be dealt with appropriately

Source: LEI analysis

7 Performance-based regulation model

PBR, as a regulatory approach to rate regulation, provides a wide range of mechanisms, which allow the link between a utility's rates and its unit costs to weaken, thus, improving efficiency. It is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime as discussed in Task 2.1.1.

The Project Team envisions three possible variants of the PBR model, building on current PBR components as well as the proposed PBR for Hawaii:

- Option 1: Light PBR employs an expanded list of performance incentive mechanisms ("PIMs") with the current earnings-sharing mechanism ("ESM");
- Option 2: Conventional PBR employs a revenue cap with an indexation formula;
- Option 3: Outcomes-based PBR approach.

This section considers the feasibility of the PBR model and details the technical, financial and legal implications should the model be implemented in each level of the PBR continuum.

7.1 Technical feasibility

7.1.1 Requirements for establishment of PBR

Moving from a traditional COS regime to any variant of PBR can be a challenging task, not only for the regulator but for the utilities as well, especially during the first generation/term. It involves extensive amount of regulatory work and requires lengthy stakeholder engagement efforts particularly in determining the appropriate PBR mechanism allowing more in-depth analysis of sectoral and technical issues—discussions of which are not always present or as thoroughly dissected during a COS deliberation.

The first 'formal' step in the PBR process is when the regulator expresses its intent to implement a shift. In this step, the regulator would be expected to explain the objectives clearly to all stakeholders as it embarks in the process. For example, in the case of Alberta, the Commission highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies toward improvement of efficiency while ensuring that benefits from the increase in efficiency will ultimately benefit customers.[86]

The following principles need to be assessed collectively so the goals of the move to PBR may be determined as the State decides upon a regulatory regime or a change in regime:

[86] Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237. September 12, 2012. Page 5. Accessed at: <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

- ***Incentives compatibility:*** Ratemaking should provide appropriate incentives to both companies and customers (although some natural conflicts may occur, and tradeoffs made).

- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and sufficient cash flow to support necessary investment.

- ***Administrative simplicity and transparency***: Rates should be straightforward for customers to understand; customers should be able to calculate their monthly bills themselves and understand why the rate is calculated in the prescribed fashion.

- ***Cost causation and avoidance of cross-subsidies***: To achieve the most efficient patterns of consumption, economic theory states that customers that cause a cost to be incurred should pay for that cost.

- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions.

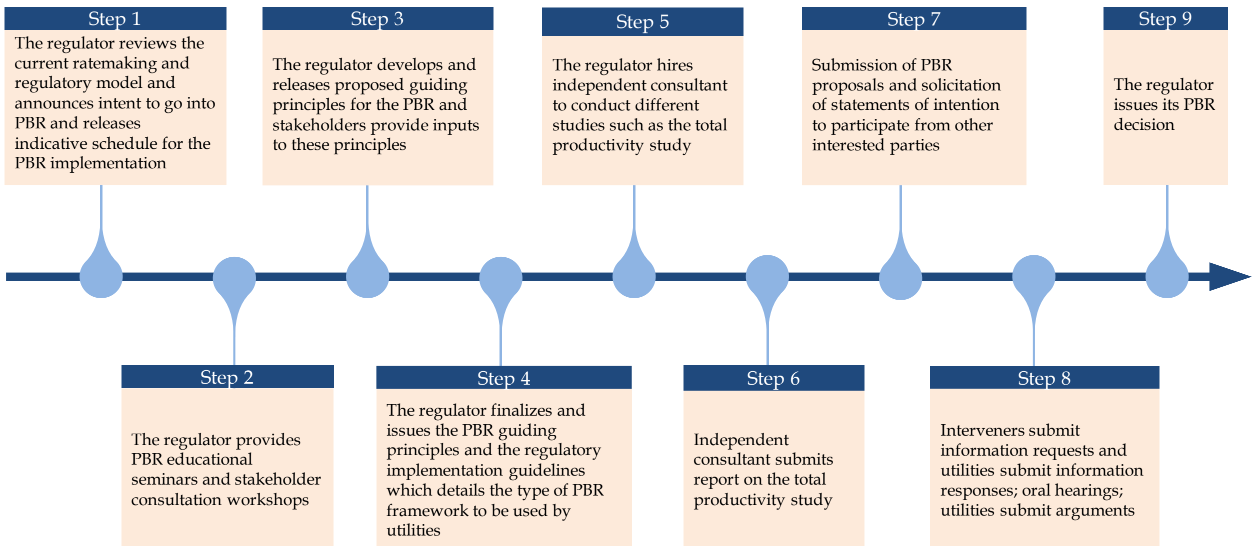
Experience and best practice dictate that the shift to a PBR mechanism requires the establishment of principles that should guide stakeholders (particularly the utilities) in the development and implementation process. The establishment of these principles assists the regulator in evaluating PBR proposals and guides the utilities in developing the most responsive and relevant proposals.

The move to PBR may also involve the hiring of an economic consultant who could assist in determining the appropriate PBR approach, identifying appropriate components (such as incentives and magnitude of rewards or penalties for the performance standards), reviewing what data is currently available, or providing a study of historical and forecasts of inflation and productivity trends. It is also crucial that the regulators and stakeholders be regularly communicating and on the same level of understanding. Workshops and technical conferences are generally conducted to familiarize stakeholders with the proposed PBR approach and solicit feedback.

The typical high-level steps involved in the transition to a PBR model are illustrated in Figure 6.

The feasibility of PBR requires two essential elements: data availability and forecasting. Data availability plays a vital role in the development of a PBR regime and would improve the functionality of PBR regulation over time. Data could often be inconsistent or unavailable because of differing or lack of clear reporting guidelines, varying cost allocation methods employed by each utility, changes and differences in accounting techniques, and mergers and amalgamations, among others. The need for good data cannot be understated; incentive design could be significantly weakened by poor data. "Comprehensive" forms of PBR require collating and employing multi-period information and data samples covering multiple utilities. Over time, the availability of reliable, comparable, and accurate data on the industry and the utilization of "best practice" forecasting tools would improve the ease of the PBR ratemaking process. By doing so, this facilitates analysis and negotiations of parameters for PBR factors as well as benchmarking actual productivity achieved against prior targets. Ensuring data consistency and credibility requires configuring systems and processes correctly. Utilities could review current systems and record-keeping practices and configure them to capture the data required for filing. Appointing a Chief Data Officer, who could ascertain data accuracy and consistency, would be useful to prevent errors.

Figure 6. High-level Steps in the Move to PBR



Source: LEI analysis

Furthermore, the preparation of PBR filings requires the ability to forecast additional elements that may have been less critical under a COS regime.[87] Forecasting plays a central role in the building blocks approach-based PBR. Poor forecasting by utilities may lead to additional costs and/or penalties affecting their bottom line. Realistically speaking, forecasts could significantly deviate from actual figures. Therefore, the PBR design must include mechanisms that would provide a degree of protection to both shareholders and ratepayers. Such mechanisms may include re-openers, ESM, true-ups, rebasing, and flow-throughs.[88] Benchmarking and trend analysis could also be used to compare differences in actual and proposed costs and guide regulatory decisions, for example, in increasing or reducing the utilities' forecast expenditures.

---

[87] Items to forecasts include load growth, energy growth, depreciation, number of customers, cost of capital, operating expenditure, capital expenditure, and tax expenditure, to name a few.

[88] In UK, Ofgem developed an innovative mechanism called the menu approach or the information quality incentive to address forecasting challenges in capex and opex. This mechanism provides an incentive to utilities to present reasonable estimates of their true investment needs and penalize them if the information is misleading. It allows utilities to choose an implicit "regulatory contract" that provides the best incentive to declare the most accurate investment plans. In addition, it rewards utilities with lower expenditure forecasts and provides for utilities with higher expenditure forecasts to beat the targets by spending less.

Overall, key success factors in PBR implementation in jurisdictions that have adopted this regime since the 1990s [such as the United Kingdom ("UK") and Australia] include:

- PBR design's adaptability to changing environment;
- provision of incentives to encourage cost efficiency and quality of service;
- presence of clearly defined and efficient planning process for network investments; and
- adoption of a clear framework that supports funding of capital expenditure through rates.

Further details regarding jurisdictions that have adopted PBR are in Tasks 2.1.1 (Introduction to the Regulatory Models) and 2.2.2 (Case Studies).

7.1.2 Impact on the roles and responsibilities of the Commission

Under this new regulatory model, the value chain would remain the same, where the incumbent vertically-integrated utilities would continue to own and operate generation, transmission, and distribution assets. However, the PUC would have additional oversight under the PBR model. More specifically, the Commission would be responsible for administering implementation of the PBR model. PBR oversight includes, but is not limited to, the following:

- identifying the performance indicators that would be used to measure the following: (i) cost control; (ii) efficient investment; (iii) "rapid" integration of renewables; and (iv) timely execution of competitive procurement;
- determining the targets that utilities need to achieve for each of the aforementioned metrics;
- in the case of the Outcomes-based PBR, determining the desired outcomes that the utilities are expected to achieve;
- setting up rewards and penalties for achieving or missing targets;
- if needed, designing necessary incentives that drive innovative approaches from the utility;
- reviewing the PBR plan that the utilities submit and ensuring that forecasted costs are reasonable; and
- reviewing utilities' performance (financial and operations) to ensure that they have achieved the outcomes and/or targets set and approved revenues were prudently spent.

Despite this increased responsibility, PBR regimes are typically expected to lead to an overall reduction in the regulatory burden in the long term, primarily due to a lower frequency of regulatory proceedings (when compared to markets under a COS approach) and a less fastidious review of costs.[89] As such, reduced regulatory costs under a PBR are a result of PBR's recognition of the information asymmetry between the regulator and the utility. Under the COS regime, regulators spend a considerable amount of time and expense to bridge the information gap. Conversely, PBR does not try to rectify this information gap. For example, under a PBR regime (that is designed correctly), the regulator does not need to know the costs for each O&M item but rather the range of possible costs from which the regulator could approve a PBR plan—particularly one that could elicit maximum efficiency from the utility.[90]

Moreover, the PBR also relieves regulators from the demanding task of micro-managing utilities' activities. For utilities, this means they could respond more quickly to technological and competitive challenges and, for customers, this leads to lower prices in the long term.

While these changes would not result in additional infrastructure for the Commission, the change in responsibilities may lead to a change in amount of work, thereby resulting to more staffing. Conversely, the changes in the Commission's role may simply alter the nature of the work itself.

7.1.3 Impact on the roles and responsibilities of utilities

As previously mentioned, the PBR model itself would not change the electric power value chain or structure (unless implemented together with other regulatory frameworks, as described in the hybrid models introduced in Task 2.2.1). However, incentives for utilities would certainly be changed under the PBR model. Vertically-integrated utilities such as the HECO Companies would need to address issues concerning all three functions (generation, transmission, and distribution), including but not limited to, the following:[91]

- Preventing plants from becoming stranded assets;
- Ensuring wires are used in the most efficient way (an issue with renewable generation because renewable sites are not typically located in proximity to major transmission wires); and
- Distributing power such that sales volume, thus, revenues, are growing despite increasing DER adoption levels.

Nonetheless, the PBR's overall stronger advantages lie in its ability to facilitate increasingly efficient operations and deeper attention to quality definition and performance standards. As such, the Commission would also require extensive reporting by the utilities based on performance metrics identified under the model. The Project Team notes that the above areas of

---

[89] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[90] Comnes, G.A. S. Stoft, Green, and L.J, Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. November 1995. P. 6.

[91] National Renewable Energy Laboratory. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation.* September 2017. Page 31.

concern are in line with the need to measure utility performance in the proposed PBR framework for the State of Hawaii. Meanwhile, Hawaii currently has PIMs in place, where rewards or penalties are imposed if targets are met/not met by the vertically-integrated utilities.

7.1.4 Compliance with the reliability, adequacy, and quality of service standards

PBR offers many potential benefits, one of which is its ability to help utilities comply with reliability, adequacy, and quality of service standards established by the PUC over the short- and long-term. Reliability and quality of service could be safeguarded under a PBR regime, especially for plans that have mandated PIMs. More specifically, the implementation of PBR could provide strong incentives for utilities to increase performance and improve productivity because it allows them to derive significant financial benefit from doing so.[92] This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers.

The experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements. For instance, in the case of FortisBC, the British Columbia Utilities Commission noted: "*the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements*."[93] Moreover, during the 2004-2009 period, FortisBC *"exceeded the O&M targets by an aggregate amount of $87 million over the six years. Customers received 50 percent of this or $43.5 million back via the ESM."*[94] The O&M savings during FortisBC's PBR period benefited customers in two ways: (i) reduced rates during the term of the PBR via the ESM; and (ii) rebasing of the savings into opening O&M as the starting point in the setting of rates after the PBR has ended.

Another example is in the UK, where the Office of Gas and Electricity Markets ("Ofgem") stated that the RPI-X regulatory framework has brought benefits to electricity customers over the last 20 years and has "*delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices."*[95] In fact, *"since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization."*[96] Ofgem also believed that the implementation of PBR "*led to significant improvements in quality of service.*

[92] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal*. October 2001.

[93] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision, page 22.

[94] Ibid.

[95] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

[96] Ibid.

Between 1990 and 2009, the number and duration of reported outages fell by around 30 percent."[97] With that in mind, the implementation of PBR in the State of Hawaii would likely improve the utilities' compliance with the standards set forth by the PUC as well as the quality of service delivered by the system.

7.1.5 Ability to achieve State energy goals

The PBR model is considered to be the most favorable in achieving the State's RPS targets. Under a PBR model, the PUC could set incentives and penalties based specifically on progress towards pre-established goals such as rapid integration of renewables (including third-party home solar and storage systems), affordable rates, electric reliability, and customer choice and satisfaction (Specific PBR metrics could be set for any and all of these criteria.) It enables a "carrot and stick" approach that could be designed to both encourage utilities achieve target performance and penalize them for underperformance. In addition, it provides the utility freedom in optimizing its resources given targets and objectives.

7.2 Financial feasibility

7.2.1 Financial requirements for implementation

Implementation of the PBR regulatory model requires a number of important steps, which have financial implications to the Commission and utilities. These include data collection, regulatory process and timing, stakeholder engagement, and certain changes to the utility's operations—particularly for those that can help ensure achievement of the performance standards. Moreover, utilities and the regulator may hire economic consultants who could advise them on putting together the PBR plan (on the side of utilities) and reviewing the filings (on the side of regulator). This means additional regulatory costs for both the utilities and the PUC.

While timing of the proceedings remains within the purview of the Commission, PBR proceedings tend to be longer than COS cases. This is because PBR proceedings involve additional discussion and analysis of technical issues such as those related to productivity trends, inflation factor, and rewards and/or penalties for performance standards.

Based on the experiences of jurisdictions such as Alberta, Ontario, Australia, and UK, the regulatory process has been observed to be longer under PBR, usually requiring 17 to 32 months, compared to the 12 to 18 months for a COS regulatory process. The experiences of these jurisdictions are illustrated in Figure 7. The PBR process and timing are usually shaped by the number of utilities and interveners that participate in the regulatory process, PBR framework that the jurisdiction is using (whether it is the indexing approach or building blocks approach), and the generation that the regulatory model is in. Proceedings may take longer in the first generation than in subsequent ones.

[97] Ibid.

Figure 7. Process and Timing in PBR (Selected Jurisdictions)

	Alberta	Ontario	Australia	UK
Framework	I-X approach	I-X approach	Building blocks approach	RIIO model
Generation of model	2nd	4th	4th	6th
Number of electric distribution utilities	4	70	13	14
Process	Involves information requests and responses, oral hearings, and rebuttal	Involves information requests and response, oral hearings, and rebuttal	"Propose-respond" model	"Propose-respond" model
Process name	PBR application	Incentive Rate Mechanism ("IRM")	Price determination	RIIO-ED1
Timing	33 months	17 months	19 months	32 months

Source: Alberta Utilities Commission, Ontario Energy Board, Australia Energy Regulator, and Ofgem

At the same time, there is no required investment in enabling technology or software or the creation of new regulatory institutions in implementing PBR. For the utility, it would be useful but not necessary to have a collaboration and document management systems that could help it track, manage, and store documents related to the PBR filings. As discussed earlier, data availability is important under PBR and having a system to do this would be useful to the utility in the long-run. Existing Commission staff and infrastructure could be sufficient to enable the transition to this regulatory model and could be supplemented by additional staff (or consultants) who could help facilitate the stakeholder engagement efforts.

7.2.2 Financial impact on the Commission, utilities, and ratepayers

A well-designed PBR offers many potential benefits to regulators, utilities, and customers. These benefits include superior performance incentives, improved rate predictability,[98]timely consumer benefits, lower administrative/regulatory costs (in the long run), and greater compatibility with a rapidly changing industry. For the utility and the ratepayers, the financial impact of the implementation of a PBR regulatory model is dependent largely on the design of the PBR regime.

When designing a PBR regime, careful consideration in deciding the individual components of the PBR formula is required. These components, which could include an inflation factor, productivity factor, earning sharing mechanism, performance standards, and "off-ramp" triggers, among others, need to be viewed as a whole rather than individually. Collectively, the

---

[98]Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal*: 20-29.

PBR formula needs to follow key principles in ratemaking—for example, the need to ensure financial stability of utilities and safeguard their ability to earn a commercially reasonable rate of return, administrative simplicity, ease of understanding for ratepayers, and alignment of incentives between shareholders and ratepayers. Nevertheless, COS ratemaking principles continue to be relevant under a PBR approach, including those that facilitate the determination of "going in rates."

Often, utilities are concerned that their financial viability may be undermined if there would be substantial capex requirements (which are not usually recognized in a timely manner in the PBR indexation formula) or if actual conditions depart from "test year" or historical conditions. Some regulators have addressed this issue by prescribing forward capital planning. Regulators are also dealing with such challenges through capex incentive mechanisms[99] although such mechanisms complicate the administration of the PBR regime. Other jurisdictions have incorporated adjustment factors within the PBR formula to address capital cost issues or have modified the PBR design, so the treatment of the capex becomes a cross between COS and "comprehensive" forms of PBR.

The targets set for efficiency and productivity need to be balanced against the financial viability of the utility and consideration of costs that are within management's control. This benefit is precisely the incentive that motivates utilities in competitive markets to control costs and deliver exceptional service to their customers. As detailed in Section 7.1.4, the experiences of some jurisdictions that have implemented PBR illustrate its beneficial role in encouraging productivity improvements.

7.3 Legal feasibility

7.3.1 Hawaii Ratepayer Protection Act

The Hawaii Ratepayer Protection Act, which essentially mandates a form of PBR in Hawaii, was signed into law on April 24, 2018 and took effect on July 1, 2018.[100] This new law seeks to address concerns that the traditional regulatory approach does not provide appropriate incentives to utilities, so they could meet the challenges of a renewable and distributed energy future.[101]

There is a need to update the regulatory framework, so the State can align the utilities' financial interests with public interest. The Legislature was "*concerned that the existing regulatory compact misaligns the interests of customers and utilities because it may result in a bias toward expending utility*

[99] An example of a capex incentive mechanism is the efficiency carryover scheme ("ECS") that is being implemented in Australia and the Philippines. An ECS encourages prudent and efficient capex spending and shares the benefits of capital efficiencies with the customers.

[100] Gov. Msg. No. 1105 (April 24, 2018); *see also* 2018 Haw. Sess. Laws Act 5.

[101] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by independent third parties."[102]

The Legislature explained that the purpose of the Ratepayer Protection Act is "*to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues.*"[103]

The law further directs the PUC to create "*performance incentives and penalty mechanisms that … break the direct link between allowed revenues and investment levels*" by January 1, 2020.[104] The performance incentives and penalty mechanisms are expected to be applied through the PUC's regulation of electric utility rates under HRS § 269-16.[105]

In developing performance incentives and penalty mechanisms, the Hawaii Ratepayer Protection Act requires the PUC to consider economic incentives, penalties, and cost-recovery rules that promote affordability of rates, electric reliability, customer choice and satisfaction, data transparency, rapid integration of renewables, and timely execution of competitive procurement and other business processes.[106] Note that the Ratepayer Protection Act specifically exempts member-owned cooperative electric utilities such as Kauai Island Utility Cooperative ("KIUC").[107]

7.3.2 PBR Docket 2018-0088

On April 18, 2018, the PUC issued Order No. 35411, *Instituting a Proceeding to Investigate Performance-Based Regulation*, on April 18, 2018, opening Docket No. 2018-0088 ("Order 35411"), a proceeding that would investigate the PBR for the HECO Companies ("PBR Docket").[108] The PUC intends for the PBR Docket to be "*a forum by which to evaluate the current regulatory environment; identify which elements, if any, may not adequately align with the public interest; and collaboratively develop modifications or new components to better align utility and customer interests.*"[109] The PUC seeks to "*(1) identify specific areas of utility performance that should be improved; (2) determine*

---

[102] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1.

[103] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 1. (Emphasis added.)

[104] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3. (Emphasis added.)

[105] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3. *See* § 269-16. Regulation of utility rates; ratemaking procedures.

[106] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5.

[107] *Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[108] Order No. 35411.

[109] Order No. 35411, at 51.

appropriate metrics for measuring successful outcomes in those areas; and (3) establish reasonable financial rewards and/or penalties that are sufficient to incent the utility to achieve those outcomes."[110]

The PUC explained that PBR includes a "*set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes as opposed to simply growth in capital investments or other determinants of utilities earnings*" under traditional COS rate regulation.[111] PBR offers regulators a way to restructure utility financial incentives to achieve broad objectives such as incentivizing cost reduction and achievement of policy goals, improving unsatisfactory performance, integrating technological advances, and supporting customer choice.[112]

The current regulatory framework implemented by the PUC under its existing authority already includes

> "*in at least some form, several of the fundamental components ordinarily associated with PBR, including [a Multi-Year Rate Plan] (fixed three-year cycle for general rate cases), an interim-period revenue adjustment mechanism subject to a revenue cap, a revenue decoupling mechanism, and an [Earnings Sharing Mechanism]. In addition, several [Performance Incentive Mechanisms] are already in place, and others are actively being contemplated, including [Performance Incentive Mechanisms] rewarding successful implementation of new renewable programs and procurement of utility-scale renewable generation*."[113]

In the PBR Docket, the PUC stated that it is particularly interested in PBR mechanisms that result in:

- "*Greater cost control and reduced rate volatility;*
- *Efficient investment and allocation of resources regardless of classification as capital or operating expenses;*
- *Fair distribution of risks between utilities and customers; and*
- *Fulfillment of state policy goals*." [114]

The PBR Docket proceeding will be implemented in two phases:

---

110 Order No. 35411, at 52.

111 Order No. 35411, at 13.

112 Order No. 35411, at 14.

113 Order No. 35411, at 40-41. (Footnotes omitted.)

114 Order No. 35411, at 5.

- In Phase 1, the current regulatory framework will be assessed and evaluated. Specific areas of utility performance that should be targeted for improvement and metrics for determining successful outcomes in those areas will be identified. [115]

- In Phase 2, the PUC will focus on refinements and modifications that can be made to the existing regulatory framework in order to incentivize the utility to achieve those outcomes. New PBR frameworks (including those for performance incentives and increasing the alignment between utilities' and customers' interests) will be developed. [116]

The Commission expects Phase 1 to conclude in "*approximately nine months*" while Phase 2 will take approximately 12 months.[117]

Under Order No. 35411, the PUC excused KIUC from involvement in Docket No. 2018-0088 because the method used by KIUC in determining rates, which is the Times Interest Earned Ratio approach discussed previously,[118] is "*unlikely to present the same potential risks to KIUC's customers as compared to those present for customers of for-profit*."[119]

7.3.3 Existing legal framework for the regulatory model

There is no comprehensive PBR legal framework yet. However, as described above, the legal framework for the establishment of the PBR model in Hawaii is currently under development pursuant to the requirements of the Ratepayer Protection Act and by the PUC in the PBR Docket. The Ratepayer Protection Act, as discussed above, requires the PUC to "*establish performance incentives and penalty mechanisms that directly tie an electric utility's revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels*" by January 1, 2020.[120] The PUC expects to conclude both phases of the PBR Docket in approximately 21 months.[121]

---

[115] Order No. 35411, at 53.

[116] Order No. 35411, at 55.

[117] Order No. 35411, at 55.

[118] *See* Task 2.1.2. – "High-level and general assessment of the existing regulatory model in place in Hawaii," Section 3.4.3.

[119] Order No. 35411, at 9-10.

[120] *See Hawaii Ratepayer Protection Act,* 2018 Haw. Sess. Laws Act 5, § 3.

[121] Order No. 35411, at 55. The PBR Proceeding was opened on April 18, 2018.

7.3.4 PUC authority under current legal and regulatory framework

As described above, the current regulatory framework already includes some form or components of PBR.[122] In addition, the PUC opened the PBR Docket proceeding under its existing general investigative authority and Legislative guidance on issues it may consider under HRS §§ 269-6, & -7, even prior to the enactment and effective date of the Ratepayer Protection Act.[123] The Ratepayer Protection Act, as discussed above, establishes the PUC's authority further in implementing PBR consistent with the Ratepayer Protection Act and, in fact, mandates the implementation of PBR as provided in the Ratepayer Protection Act. Accordingly, the PUC's authority to implement the PBR model should be firmly established so long as it is consistent with existing authority, the Ratepayer Protection Act, and any other applicable law.

7.3.5 Statutory changes or laws required for implementation

The Ratepayer Protection Act as described above likely provides sufficient legislative authority and policy direction to the PUC in implementing the PBR model in Hawaii as well as the provisions of the Act itself.

7.3.6 Administrative actions required by the PUC

The PUC must, as discussed above, implement the Ratepayer Protection Act so it can establish performance incentives and penalty mechanisms that will (1) "*directly tie*" the revenues of an electric utility to its achievement of performance metrics (which must be determined), and (2) "*break the direct link*" between the utility's revenues and investments. Moreover, the Ratepayer Protection Act explained that its purpose is to protect consumers by updating the existing utility and regulatory business model, which requires that "*electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues*." Furthermore the "*performance incentives and penalty mechanisms…shall apply to the regulation of utility rates under [HRS] section 269-16.*" Therefore, the "*performance incentives and penalty mechanisms*" mandated in the Ratepayer Protection Act must be established administratively by the PUC for the PBR model in Hawaii.

The PUC has, as discussed above, already embarked on an investigative docket proceeding to evaluate the current regulatory environment and develop modifications or new components to better align utility and customer interests, by initiating the PBR Docket. The PUC initiated the PBR Docket pursuant to its general investigative and supervisory authority over public utilities under HRS §§ 269-6, & -7. Although the PUC opened the PBR Docket prior to the enactment and effective date of the Ratepayer Protection Act, the PBR Docket appears to be generally consistent with the intent of the Ratepayer Protection Act and to the extent required, the PUC may adjust the issues that must be considered in the PBR Docket so as to directly satisfy the requirements of the Ratepayer Protection Act.

---

[122] Order No. 35411, at 40-41. (Footnotes omitted.)

[123] Order No. 35411, at 6.

Alternatively, the PUC may also exercise its rulemaking authority as an administrative agency that could initiate a rulemaking process following the implementing rules of the Ratepayer Protection Act, as authorized by HRS Chapter 269.[124]

7.3.7 Additional legal issues

The Ratepayer Protection Act, as discussed above, provides that it applies to the regulation of electric utility rates under HRS § 269-16, which is the governing provision in HRS Chapter 269 on public utility ratemaking by the PUC. Under such statute, the PUC is generally required to provide regulated public utilities with an opportunity to earn a fair or reasonable rate of return on property used to provide regulated public utility services.[125]

Similarly, it should be noted that depending on how rates are determined and enforced, rates that are not sufficient to yield a reasonable return on property used for utility services may be determined to be confiscatory and violate certain constitutional requirements."[126]

As mentioned, the Ratepayer Protection Act requires the PUC to establish performance incentives and penalty mechanisms. Functions such as these certainly require legal mandates.

The PUC has already recognized that the PBR model, which would be developed and implemented in Hawaii should continue to provide electric utilities with an opportunity to earn a fair return on its property:

> *PBR includes a set of alternative frameworks and regulatory mechanisms intended to focus utilities on performance and desired outcomes, as opposed to simply growth in capital investments or other determinants of utility earnings under COSR. Well-designed PBR frameworks should result in an incentive structure that encourages exemplary utility*

---

[124] *See* HRS § 269-6(a):

> (a) The public utilities commission shall have the general supervision hereinafter set forth over all public utilities and shall perform the duties and exercise the powers imposed or conferred upon it by this chapter. Included among the general powers of the commission is the authority to adopt rules pursuant to chapter 91 necessary for the purposes of this chapter.

[125] HRS § 269-16(b) ("The commission, upon notice to the public utility, may . . . [d]o all things that are necessary and in the exercise of the commission's power and jurisdiction, all of which as so ordered, regulated, fixed, and changed are just and reasonable, and provide a fair return on the property of the utility used and useful for public utility purposes."); *see also* Order No. 35411 ("With the traditional [Cost of Service Regulation] framework, utility rates are set to allow electric utilities a reasonable opportunity to recover the costs incurred to provide general service, including a return on investment. An electric utility realizes earnings through a rate of return on the utility's capital investments, provided the regulator finds those capital investments were just and reasonable."); *cf.* Decision and Order No. 31288, issued in Docket No. 2011-0092, on May 31, 2013, Exhibit C, at 3 ("While a public utility is required to have a reasonable opportunity to earn a fair financial return, attractive financial returns are not an entitlement by virtue of being a regulated utility.").

[126] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 43 S.Ct. 675, 690 (1923) ("Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.").

*performance irrespective of the nature of its investments (e.g., investment in capital expenditures verses investment in measures by a non-utility, third party). By providing rewards for specific outcomes and objectives, **a PBR framework should provide a utility with the opportunity to earn fair compensation, based on a business model that is well aligned with the public interest***.[127] [Emphasis added.]

Therefore, the PBR model, which would be developed and implemented in Hawaii should be carefully designed so it could provide the electric utility with an opportunity to earn a fair return on its property.[128]

7.4 Conclusion

The PBR regulatory model has few feasibility risks as compared to the other regulatory models. The challenges faced in implementation are mainly in data collection, stakeholder engagement, and increased regulatory timing. Given that the utility structure remains largely unchanged under this regulatory model, there are no transition risks and need for the creation of new entities. Under these evaluation criteria, this regulatory model is ranked as neutral or low risk (Figure 8).

Figure 8. PBR Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	No change expected given existing PBR rate case
	Compliance with service standards	(+) Incentive mechanisms can be designed to target specific service and quality standards
	Achievement of State clean energy goals	(+) Commission can set incentives and penalties that directly target pre-established goals
Financial Feasibility	Implementation requirements	(-) Data collection, stakeholder engagement and increase in time required
	Impact on ratepayers	(+) Earning sharing mechanisms allow efficiency gains to be shared
	Impact on utilities	(+/-) Depends on the design of the incentives and components of the formula
Legal Feasibility	Existence of supporting legal framework	(-) Current PBR regulatory framework is under development in the PBR docket
	Governance requirements	(+) Provisions exist in the Ratepayer Protection Act but must be implemented by the PUC
	Additional legal factors	(+) Implementation must also take the requirement to provide a reasonable return for utilities into consideration

Source: LEI analysis

[127] Order 35411, at 13-14.

[128] A distinction between existing investments and investments to be made subsequent to implementing a PBR model may also be considered. To the extent that there may be an issue of stranded costs for existing investments, the PUC is statutorily authorized to establish a mechanism that would allow electric utilities to recover stranded costs related to early retirement of fossil fuel generation plants. *See* HRS § 269-6(d)(3).

8 Lighter regulation for cooperatives

As described in Task 1.1.1, cooperatives ("co-ops") are organizations or companies that are effectively owned by their members, who are generally their customers. They are incorporated under the laws of the state in which they operate. In Hawaii, the island of Kauai is served by KIUC. KIUC operates as a co-op utility—meaning, it is owned and governed by its members (who receive services from KIUC) and is not an IOU or owned by a third-party investor.[129] KIUC is regulated by the PUC—an arrangement that is largely unique to Hawaii.

The regulatory models discussed in the earlier sections are not applicable to co-ops, thus, not applicable to KIUC in the State of Hawaii. In this regulatory model proposed by the Project Team and as discussed in Tasks 2.1.1 and 2.2.1, co-ops would be subject to lighter regulation from the PUC and would have some control from the Board of Directors as well as members. Under this Lighter Regulation model, co-ops may be exempted from certain regulations, which were established based on an investor-owned utility ("IOU") structure. These could include PUC regulations for the approval of rate setting and design, power purchase agreements with IPPs, fuel contracts, and large capital expenditures, particularly if such transactions do not exceed a particular threshold. Such thresholds regarding rate increases and capital expenditures would be established to trigger review by the Commission. State energy goals would remain applicable to co-ops.

8.1 Technical feasibility

To facilitate the Lighter Regulation model, the Board of Directors, who are selected as per the by-laws of the co-op, would continue to approve operating and capital budgets, develop plans taking into account the interest of the members, and ensure the adequacy of electricity supply. Co-ops would remain under the regulatory oversight of the Rural Utilities Service ("RUS") in terms of planning, financing and capital investments.[130]

When it comes to the utility's roles and responsibilities, the co-op would retain its existing mandate, which is to ensure reliable and least-cost power for its members and pursue strategies that would help achieve this as directed by its members. Members, through the Board of Directors (and their voting system), are free to decide the level of reliability standards and renewable targets that they desire.

For the regulator, this reduction of regulatory jurisdiction over the co-op would mean it may have less control in ensuring that the co-op's goals align with State energy goals (which are outlined

---

[129] Order No. 19658, filed in Docket No. 02-0060, on September 17, 2002, at 12.

[130] The RUS is a program under the US Department of Agriculture whose mandate is to administer programs that provide much-needed infrastructure or infrastructure improvements to rural communities. Programs include provision of capital and leadership to maintain, expand, upgrade and modernize their electric infrastructure, loans and loan guarantees finance the construction or improvement of electric facilities and funding to support demand-side management, energy efficiency, and conservation programs. (Source: United States Department of Agriculture. *Rural Utilities Service website.* Accessed at https://www.rd.usda.gov/about-rd/agencies/rural-utilities-service)

in Section 3.1). Therefore, there is no assurance that the co-op would be able to help achieve the State's goals under Lighter Regulation.

Historically in Hawaii, KIUC has maintained renewable energy as one of its strategic priorities and is currently seeking to remain ahead of the State goal of 100% renewable energy by 2045. Its current target is to source 70% of all its electricity by 2030, ahead of the state energy goal of 40% by the same year.[131]

8.2 Financial feasibility

There would be no financial requirements for the co-op nor the utility with the implementation of Lighter Regulation. In fact, there would be additional benefits of reduced costs by not participating in regulatory dockets and regulatory compliance. For the existing co-ops, regulatory as well as fees paid to the PUC costs would decline, the saved funds potentially remaining with would remain with them. For customers, the decline in regulatory costs may translate to lower costs.

8.3 Legal feasibility

Under the Lighter Regulation for co-ops model (which would apply to KIUC only), the regulatory framework would be customized substantially to reduce regulation of KIUC as a public utility.

8.3.1 Existing legal framework for the regulatory model

Currently, KIUC continues to be overseen by the PUC—similar to the HECO Companies and unlike most cases of co-ops on the mainland. Due to concerns of what may occur if KIUC were to be deregulated, the co-op agreed not to seek complete regulatory exemptions from the PUC or support legislation deregulating its services until January 2008.[132] Since then, generally, KIUC has still been regulated by the PUC, which has statutory authority to do so.[133]

However, the regulation of KIUC has been relaxed in certain aspects. For example, KIUC is not required to undergo the Power Supply Improvement Process or the Distributed Generation Interconnection Plan, unlike the HECO Companies.[134] Moreover, the PUC approved KIUC's exemption from the Competitive Bidding Framework that governs the procurement process of

---

131 Kauai Island Electricity Cooperative. *Clean Energy*. Accessed at: <http://kiuc.coopwebbuilder2.com/content/clean-energy>

132 Stipulation in Lieu of Preliminary Position Statements, filed in Docket No 02-0060, on July 18, 2002 at 30 ("KIUC will not petition the Commission nor seek or support any legislation that would have the effect of reducing or eliminating any element of existing Commission jurisdiction over KIUC through at least December 31, 2007").

133 HRS § 269-31(b).

134 KIUC's Final Statement of Position, filed in Docket No. 2014-0192, on June 29, 2015 at n.1 at 2; *See* Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014, at n. 8 at 6. *See also* Order No. 32257, filed in Docket No. 2014-0183 on August 7, 2014 at 1.

the HECO Companies.[135] Furthermore, the PUC will often open dockets on specific items focusing solely on the HECO Companies such as the PUC docket proceeding on Grid Modernization.[136] Most recently, as discussed above, KIUC is exempted from the requirements of the Ratepayer Protection Act and the PBR Docket. However, KIUC is required, on occasion, to participate in certain dockets opened by the PUC. For example, KIUC was made part of the Community Based Renewable Energy Program docket[137] and also required to participate in the Distributed Energy Resources docket.[138]

Similarly, the PUC may on its own motion or upon request issue a declaratory order to address a controversy or remove uncertainty in rules in order to determine how public utility laws and rules should be applied (or not applied) to KIUC.[139] More specifically, under existing law, the PUC is authorized to waive or exempt an electric co-op from requirements under HRS Chapter 269 or any PUC rules or orders under certain circumstance:

> *"Notwithstanding any provision of this chapter or any franchise, charter, law, decision, order, or rule to the contrary, the public utilities commission, sua sponte or upon the application of an electric cooperative, may waive or exempt an electric cooperative from any or all requirements of this chapter or any applicable franchise, charter, decision, order, rule, or other law upon a determination or demonstration that such requirement or requirements should not be applied to an electric cooperative or are otherwise unjust, unreasonable, or not in the public interest. Notwithstanding the above, the public utilities commission and the consumer advocate shall at all times consider the ownership structure and interests of an electric cooperative in determining the scope and need for any regulatory oversight or requirements over such electric cooperative."*[140]

Therefore, under HRS § 269-31(b), PUC may waive or exempt KIUC from specific regulatory requirements. Theoretically, KIUC could submit an application to the PUC under HRS § 269-31(b) to waive some or all of any applicable regulatory requirements particularly that the time period allowed for KIUC's stipulation that it would not seek deregulation has already passed as

---

135 Order No. 23298 Instituting a Proceeding to Investigate Competitive Bidding for New Generating Capacity in Hawaii, filed in Docket No 03-0372, on March 14, 2007.

136 Docket No. 2017-0226.

137 Order No. 33268, filed as a Letter Notice, on October 21, 2015 at 1; *See* Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014 at 1; *See* Order No. 33747, filed in Docket No. 2015-0382, on June 7, 2015; *See also* KIUC's Comments to the Proposed Statewide CBRE Program, filed in Docket No. 2015-0389, on March 1, 2017.

138 Order No. 32269, filed in Docket No. 2014-0192, on August 21, 2014 at 1.

139 HAR § 6-61-160.

140 HRS § 269-31(b).

of January 1, 2008.[141] However, HRS § 269-31(b) does not expressly authorize the PUC to amend or revise any regulatory requirements for that may be applicable to electric co-ops such as KIUC.

8.3.2 PUC authority under current legal and regulatory framework

Although there is an existing legal framework (both statutory and case law authority) that would allow the PUC to waive or exempt electric co-ops from any and all regulatory requirements (i.e., for KIUC to be deregulated),[142] there is currently no authority for the PUC to otherwise revise or customize regulatory requirements for electric co-ops that are unique from the regulation of IOUs under a Lighter Regulation model.

8.3.3 Statutory changes or laws required for implementation

Assuming that the intent is to customize regulatory requirements that are applicable to electric co-ops (in addition to simply waiving or exempting electric co-ops from certain or all regulatory requirements), the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so.

8.3.4 Administrative actions required by the PUC

To further implement the Lighter Regulation model for electric co-ops, the PUC could waive or exempt KIUC from any or all applicable laws or regulations pursuant to its authority under HRS § 269-31(b).

As discussed above, if the intent is to customize regulatory requirements that are applicable to co-ops (in addition to simply waiving or exempting them from certain or all regulatory requirements), and if the State Legislature authorizes the PUC to do so with any such further legislation, the latter would then be required to proceed with customizing any statutory regulatory requirements for electric co-ops.

8.3.5 Additional legal issues

Other than the legal issues described above, there appears to be no other significant legal issues at this time.

8.4 Conclusion

The Lighter Regulation model has few financial risks as well as technical risks for implementation. However, the benefits gained from reduced regulatory costs and compliance because of independence from or reduced dependence on the PUC may be lost from weaker oversight and potential mediation during board-member disputes. That being said, given the existing legal framework for co-ops in adopting the Lighter Regulation and the PUC's authority to relieve co-ops from regulatory requirements, the Lighter Regulation model for co-ops presents

---

[141] Stipulation in Lieu of Preliminary Position Statements, filed in Docket No. 02-0060, on July 18, 2002 at 30 and 32.

[142] HRS § 269-31(b); HAR §§ 6-61-159, 160.

little legal barriers. In consideration of this, the Lighter Regulation model ranks as neutral in terms of overall feasibility (Figure 9).

Figure 9. Lighter Regulation Model: Feasibility Criteria Summary

Criteria	Categorization	Various Considerations
Technical Feasibility	Implications for role and responsibilities	No change expected
	Compliance with service standards	(-) Reduced oversight from PUC may lead to less stringent compliance to service standards
	Achievement of State clean energy goals	(-) Lack of PUC oversight may hamper direction to achieve state goals
Financial Feasibility	Implementation requirements	No change expected
	Impact on ratepayers	(+/-) Lower costs may be offset by reduced oversight
	Impact on utilities	(+) Reduced regulatory compliance costs
Legal Feasibility	Existence of supporting legal framework	(+) Legal framework exists to support the waiving or exemption of co-ops from regulatory requirements
	Governance requirements	(-) State Legislature would need to customize statutory laws for co-ops or authorize the PUC to do so
	Additional legal factors	No additional significant legal issues

Source: LEI analysis

9 Conclusions

In assessing the technical, financial, and legal feasibility of each of the proposed models, namely, status quo, HERA model, IGO, distribution-focused (i.e., DSPP model), PBR, and Lighter Regulation for co-ops, the LEI team noted a number of emerging themes from this high-level and preliminary analysis:

- ***More complex regulatory models require greater changes in roles for the commission and utilities***: a review of each regulatory model suggests that the greater the technical complexity of the model, the more significant the changes in roles for the commission and utilities are. For instance, the models involving competitive markets, i.e., IGO and distribution-focused models would require substantial changes in the role of the commission especially as it transitions to oversight of competition;

- ***Transition/implementation costs are an essential factor in considering all models:*** in each model reviewed, the financial implications to the Commission, utilities, and ratepayers are linked strongly to the necessary transition costs for implementation. For the market-based models, i.e., IGO and DSPP models, careful market design and consumer education are critical success factors. For models that maintain existing utility structures, i.e., HERA and PBR, transition costs are linked to the creation and strengthening of existing institutions that would implement the respective models;

- ***Need for additional legislative processes:*** for IGO and DSSP models, the legal feasibility analysis suggests that other legislative processes would be needed to provide the necessary mandate, so the Commission could initiate these models. An assessment of the provisions given in the Ratepayer Protection Act may limit the full implementation of these models;

- ***Achievement of state clean energy goals is feasible in all models:*** the feasibility analysis suggests that achievement of the Hawaii state goal for 100% renewable energy is possible in all models provided there is careful market or incentive design.

Within the context of Hawaii, the LEI team introduced combinations of some of the regulatory models (Task 2.2.1), which may address a number of the feasibility issues that arise from each of these models. For instance, the HERA model may be paired with PBR so there would be an oversight on reliability issues. In this model, the HERA body is designed as an ombudsman that could focus on interconnection and monitoring reliability standards. The other combination is the hybrid model, which involves DSPP and IGO with Outcomes-based PBR, where the utilities function as a platform provider and an independent entity manages the dispatch and planning of the wires assets and the rates are determined based on the utilities' performance targets.

10 Appendix A: Scope of work to which this deliverable responds

2.2.3 High level assessment of the technical, financial, and legal feasibility of each regulatory model. CONTRACTOR shall provide a high-level assessment of the technical, financial, and legal feasibility of each regulatory model.

DELIVERABLE FOR TASK 2.2.3. CONTRACTOR shall provide its conclusions and all work related to technical, financial, and legal feasibility of each regulatory model. CONTRACTOR shall include any existing challenges with Hawaii statutes or regulations in terms of the regulatory model; technical issues from work conducted in TASKS 2.1 and 2.2.1 and financial feasibility analysis from TASK 2.2.2. The CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Word and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.3 to the STATE for approval.

11 Appendix B: List of works consulted

Alberta Utilities Commission. *Rate Regulation Initiative Decision 2012-237.* September 12, 2012. Page 5. Accessed at: <http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf>

Applications of Herrick, 922 P.2d 942, 954 (Haw. 1996).

Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 43 S.Ct. 675, 690 (1923

British Columbia Utilities Commission. Commission Order G-44-12. Reasons for Decision, page 22.

Comnes, G.A. S. Stoft, Green, and L.J, Hill. Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I. November 1995. P. 6.

Con Edison. Distributed System Implementation Plan (DSIP). June 30, 2016.

DeMartini & Kristov. Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation & Oversight. Lawrence Berkeley National Lab. October 2015

Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems.* Department of Energy, Washington, D.C. February 2015. Web. Access date: June 6, 2018. <ttps://www.smartgrid.gov/files/ADMS-Guide_2-11.2015.pdf>

EIA. Today in Energy. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: March 22, 2018.

Electricity Innovation Lab. New Business Models for the Distribution Edge: The Transition from Value Chain to Value Constellation. April 2013. http://www.ourenergypolicy.org/wp-content/uploads/2014/02/2013-06_eLabNewBusinessModels.pdf

"Energy Policy Directives." *Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism.* March 2017, available at: <https://energy.Hawai'i.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf>

"ERCOT Nodal 101." ERCOT. Training. Website. <http://www.ercot.com/services/training/course/109518>. Access Date: May 19, 2018.

FERC. Order No. 2000 – Regional Transmission Organizations. Docket No. RM99-2-000. December 20, 1999. Page 323.

FERC Staff. Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization. Docket No. PL04-16-000. October 2004.

FERC. Regional Transmission Organizations (Issued December 20, 1999). (Docket No. RM99-2-000; Order No. 2000), page 151.

Gov. Msg. No. 1105 (April 24, 2018); see also 2018 Haw. Sess. Laws Act 5.

Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

Hawaii House Bill No. 2525 (2012).

Hawaii Public Utilities Commission, “Approving the Release of Performance Metrics, Directing that the Approved Performance Metrics be Posted to the Websites, and Directing the Parties to Develop Additional Performance Metrics,” Order No. 32701, available at: <http://dms.puc.Hawaii.gov/dms/DocumentViewer?pid=A1001001A15C12A92431G90153>

Hawaii Public Utilities Commission, “Hawaii General Order No. 7,” available at: https://puc.Hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf

Hawaii Public Utilities Commission. “Instituting a Proceeding to Investigate Performance-Based Regulation.” Docket No. 2018-0088, filed on April 18, 2018, ("Order No. 35411"), page 9, available at <https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18D18B60624J02464>

Hawaii Ratepayer Protection Act, 2018 Haw. Sess. Laws Act 5.

Hawaii Senate Bill 2787 (2012).

HECO Companies’ Power Supply Improvement Plans; KIUC website

House Bill No. 1700 Relating to the State Budget.

HRS § 269.

HRS Chapter 269, Part IX. Electric Reliability.

HRS Chapter 269-144. Compliance and enforcement. HI Rev Stat § 269-144 (2017)

HRS Chapter 269-146. Hawaii electricity reliability surcharge; authorization; cost recovery. HI Rev Stat § 269-146 (2017).

HRS Chapter 269-30. Finances; public utility fee. HI Rev Stat § 269-30 (2017).

HRS Chapter 269-33. Public utilities commission special fund. HI Rev Stat § 269-33 (2017).

Jeff St. John. Inside SDG&E’s Plan to Optimize the Distributed Grid of the Future. Greentech Media. May 16, 2014. <http://www.greentechmedia.com/articles/read/sdge-and-spirae-break-new-ground-on-the-grid-edge>.

Joskow, P. Lessons Learned from Electricity Market Liberalization. The Energy Journal. 2008

Kauai Island Utility Cooperative. Seventh Revised and Restated By-Laws of Kauai Island Utility Cooperative. Accessed at: < http://website.kiuc.coop/content/bylaws> on June 13th, 2018.

Mayor’s Office of Economic Development, Energy Commissioner, DKK, and SES. Comparing the Structure and Function of a HERA to an ISO: Report and Task Analysis for use by the County of Maui. August 25, 2017. Page 63.

National Association of Regulatory Utility Commissioners. NARUC Manual on Distributed Energy Resources Rate Design and Compensation. November 2016.

National Association of Regulatory Utility Commissioners. NARUC Manual on Distributed Energy Resources Rate Design and Compensation. November 2016. Page 16.

National Association of Regulatory Utility Commissioners. NARUC Manual on Distributed Energy Resources Rate Design and Compensation. November 2016. Page 52.

National Association of Regulatory Utility Commissioners. NARUC Manual on Distributed Energy Resources Rate Design and Compensation. November 2016. Page 53.

National Renewable Energy Laboratory. Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation. September 2017. Page 31.

NERC. Distributed Energy Resources Task Force Report. February 2017. Access date: June 13, 2018. https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

NY PSC. Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding, (issued and effective April 25, 2014), page 12.

NY PSC. Case 14-M-0101 Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, (issued and effective May 19, 2016) (Track Two Order). Page 2.

Ofgem. Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking. January 20, 2010. P. 50.

Olson, Wayne and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." The Electricity Journal: 20-29.

Order No. 32054 Ruling on RSWG Work Product, issued in Docket 2011-0206, on April 28, 2014, at 111-113.

Order No. 35411.

PUC. Docket No. 2007-0176, Order No. 23530, issued June 29, 2007 (intergovernmental wheeling).

PUC. Docket No. 96-0493, Decision & Order No. 20584, issued October 21, 2003 (closing the docket without taking action)

PUC. Docket No. 96-0493, Order No. 15285, issued December 30, 1996 (electric restructuring for retail competition)

Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." The Electricity Journal. October 2001.

Hawaii Senate Bill 2939. Ratepayer Protection Act.

SENER; IEA, Mexico Energy Outlook. World Energy Outlook 2016

SolarCity Grid Engineering. A Pathway to the Distributed Grid: Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value. White paper. February 2016.

Tex. Util. Code Ann. § 39.151.

Texas Reliability Entity. Reliability Data Systems. Accessed at: < https://www.texasre.org/Pages/reliability.aspx>

"Today in Energy." EIA. Website. <https://www.eia.gov/todayinenergy/detail.php?id=790>. Access Date: April 19, 2018.

U.S. Const., art. I, § 10, cl. 1.

Estimating potential stranded costs resulting from a change in regulatory model in Hawaii

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

June 12th, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State of Hawaii in achieving its energy goals. As part of the engagement, this memo discusses an estimate for stranded costs that may result from a change in regulatory model for utilities in the State of Hawaii. As detailed in previous working papers, stranded costs are costs that utilities can recover through their rates but whose recovery may be hindered or averted due to competition in the industry or forced divestiture. In general, not all changes in regulatory model would result in stranded costs that then have to be recovered from ratepayers. The Project Team shows that regulatory models that introduce market-based constructs result in the potential for stranded costs for utility generation assets that range between $11 million and $32 million for HELCO, MECO, and KIUC and could surpass $300 million for HECO.

Table of Contents

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Gabriel Roumy/Utsav Adhikari
617-933-7225
gabriel@londoneconomics.com

Table of Figures

List of acronyms

CMVE	Competitive Market Value Estimate
Co-op	Cooperative utility
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DER	Distributed Energy Resource
DSPP	Distributed System Platform Providers
FERC	Federal Energy Regulatory Commission
HECO	Hawaiian Electric Company, Inc.
HEI	Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IDER	Integrated DER
IDSO	Independent Distribution System Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company, Ltd.
Munis	Municipal utilities
MW	Megawatt
PBR	Performance-based Regulation
PPA	Power Purchase Agreements
PSIP	Power Supply Improvement Plan
PUC	Public Utilities Commission
SCO	Stranded Cost Obligation
SGS	Schofield Generating Station
SPV	Special Purpose Vehicle

1 Executive summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.2.4 in the project scope of work, provides a discussion of the potential for stranded costs following a change in regulatory model for the utilities serving electric customers in Hawaii.

In a previous working paper discussing potential ownership models for the utilities serving Hawaii's counties (Task 2.1.1.),[1] the Project Team introduced four potential utility regulatory models, namely:

- status quo (cost of service) with/without increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model – Integrated Distributed Energy Resources ("IDER") operator; and
- performance-based regulation model ("PBR").

What matters most for the discussion on stranded costs is whether the utility assets, which are currently regulated and on which the utilities are allowed to earn a return on their investment, would remain under such a regulated scheme or rather would become "merchant" assets; in other words, the owner of such assets would earn a return equal to what the market can provide.

This distinction can be done along the line of functional classes of assets (generation, transmission, distribution, other) and will vary according to the regulatory model. For instance, the Project Team expects that generation assets would become unregulated under the ISO or IDER models, whereas in all other cases the utility assets would remain regulated.

In the case of models where assets remain regulated (status quo and PBR), there would not be stranded costs related to the change in regulatory regime since the utility assets, or rate base assets, have been procured under the oversight of the Public Utilities Commission ("PUC") and thus can be presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county.[2]

Should a change in regulatory model require the transfer or divestment of certain classes of utility assets, the transfer price would presumably follow a competitive process where multiple interested parties would bid to purchase either part of or the entire portfolio of utility assets that are being divested. If the assets become unregulated, or "merchant," the acquiring entity will

---

[1] Task 2.1.1. Review of potential regulatory models that could be applied in Hawaii.

[2] There may be stranded costs at the time the assets are retired if not fully depreciated, but they would not be caused by the change in regulatory regime but rather by evolution of generation resource mix.

purchase the assets at a price that allows it to cover its costs and earn their desired return on investment, based on the expected magnitude of market revenues. As discussed in Task 1.1.6., stranded costs arise if the market value of assets the utilities must divest, such as generation resources, is lower than their book value. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers.

The Project Team estimated the potential stranded costs for utility production assets in the State of Hawaii as illustrated in Figure 1. All options considered by the Project Team assume that transmission and distribution assets would remain regulated and as such would not be a source of stranded costs for the incumbent utilities should there be a change in regulatory regime.

Figure 1. Potential stranded costs for utility production assets in the State of Hawaii

Utility	Potential production assets stranded costs
HECO	$321.9 million
HELCO	$12.5 million
MECO	$11.3 million
KIUC	$31.9 million

Source: Project Team

The Project Team's estimates of stranded costs are based on several assumptions which are intended to provide a base case to estimate stranded costs. In reality, the actual magnitude of stranded costs may differ due to a variety of factors, such as:

1. market risk vs. regulatory certainty for acquiring entity;
2. higher cost of equity for merchant entities than regulated ones;
3. potential buyers having more bearish views on market conditions; and
4. single asset vs. portfolio purchase.

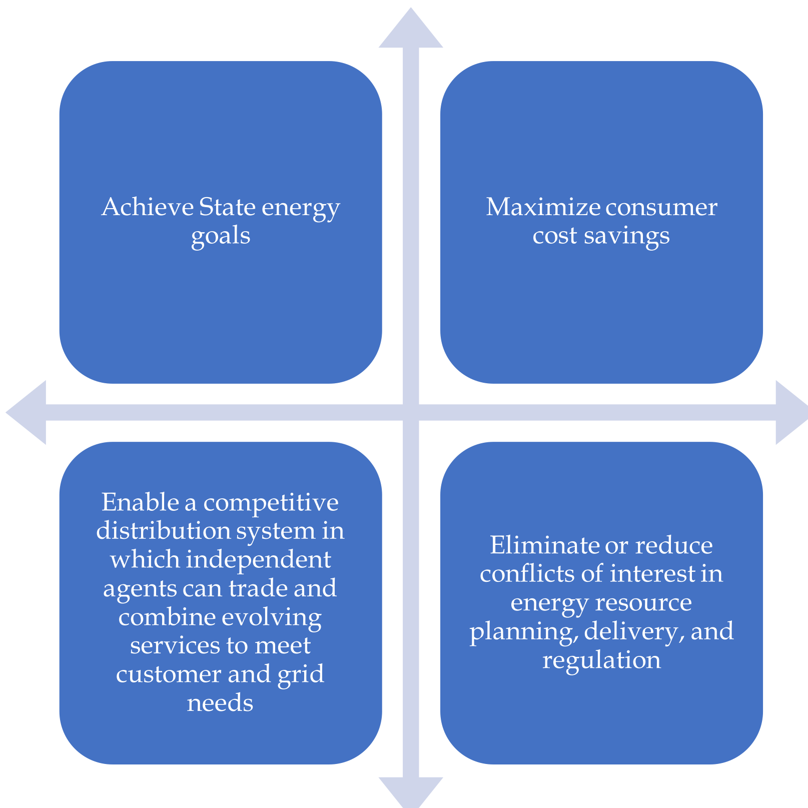
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595.

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 2.2.4. in the project scope of work. It builds on previous deliverables to discuss the potential for stranded costs related to the various ownership models introduced in the report for Task 1.1.1./Task 1.2.1. and the detailed discussion provided in Task 1.1.6., given the current regulated assets of the incumbent utilities. As noted by the team in previous working papers, an assessment of utility ownership models cannot be considered in isolation from the regulatory framework in which they are embedded. A discussion of potential stranded costs in different regulatory environments is the topic of this deliverable.

2.3 Future refinements

This deliverable includes a discussion of the potential for stranded costs for the various regulatory introduced in the report for Task 2.1.1. Since the results of the Project Team's analysis discussed in the previous deliverable are subject to further refinement and change as the project moves forward and inputs from the stakeholder groups and results of the quantitative analysis and case studies become available, the Project Team may make further refinements to the current report.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Potential stranded costs for various regulatory models

In a previous working paper discussing potential regulatory models for the utilities serving Hawaii's counties (Task 2.1.1.),[7] the Project Team introduced four potential utility regulatory models, namely:

- status quo (cost of service or "COS") with/without increased oversight;
- independent system operator ("ISO");
- distribution-focused regulatory model ("IDER"); and
- performance-based regulation ("PBR") model.

Potential regulatory models

Status quo with or without increased oversight	Independent System Operator
Distribution-focused regulatory model	Performance-based regulatory model

Although there can be significant variations within each regulatory model, the Project Team attempted to present each in a way that encompasses the most common forms.

The various regulatory models discussed range from the traditional (cost of service, performance-based regulation, or independent system operator) to other novel models such as a distribution-focused regulatory model. However, what matters for the discussion on stranded costs is whether the utility assets, which are currently regulated and on which the utilities are allowed to earn a return on their investment, would remain under such a regulated scheme or rather would become "merchant" assets – or, said another way, whether the owner of such assets would earn a return equal to what the market can provide.

This distinction can be made along the line of functional classes of assets (generation, transmission, distribution, other) and will vary according to the regulatory model. For instance, the Project Team expects that generation assets would become unregulated under the ISO or IDER models, whereas in all other cases the utility assets would remain regulated.

3.1 Regulatory models where assets remain regulated

Among the regulatory models that are being analyzed as part of this project, the Project Team discussed two ratemaking models, COS and PBR, that can be considered as traditional in the sense that operations are mostly conducted in a traditional manner, where generation, transmission, and distribution functions are conducted or coordinated by a single entity. Under those regulatory regimes, all assets in these three classes of assets remain regulated, meaning that the Public Utilities Comission ("PUC") needs to approve any investments by the utilities as well as the utility's allowed return on investment.

---

[7] Task 2.1.1. Review of potential regulatory models that could be applied in Hawaii.

- Cost of Service (status quo), with or without increased oversight

  Under a COS model, the Investor-Owned Utilities ("IOU") utilities are allowed to earn a return on prudently incurred investment, as well as pass their operating costs through to customers. KIUC, the State's only co-op, is allowed to earn sufficient revenues to earn an appropriate TIER ratio, as described in several earlier working papers. In all cases, under a straight COS model, there are no specific monetary incentives for the utilities to be efficient or minimize costs/rates.

  In the context of this analysis, increased oversight refers to the possibility of an entity being established to ensure that the State's clean energy goals will be achieved by implementing reliability standards across all the electric value chain and providing fair grid access to generators. The level of oversight should not impact the determination of the value or return on investment for assets, and as such impact on the potential for stranded costs.

  In Hawaii, all classes of utility assets (generation, transmission, distribution, other) are currently operated under a COS model, although there are some elements of PBR model in the current regulatory model, as discussed in Task 2.1.2.

- Performance-Based Regulation

  PBR is a regulatory approach to rate regulation that provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency, rewarding and/or penalizing the utility according to its performance vis-à-vis targets or performance standards.

Within those models, it is also possible to break up the vertically-integrated utility so that different regulatory regimes could be applied to a class of assets – for instance, the ISO model described below could be applied to generation assets while the "wires" (transmission or distribution) assets are operated by the utility under a COS or PBR model.

3.1.1 Discussion of potential for stranded costs

The Project Team assumes that all utility assets in all the counties are included in their respective rate base and the costs are recovered through electricity rates. While the bulk of utility assets are comprised of generation, transmission, and distribution assets, other categories such as real estate, inventory (for fuel, materials, and supplies), or "accounting" assets (such as investments related to employee pensions or deferred costs) are also included. Section 3.2 below discusses scenarios where different asset classes may be subject to different regulatory regimes.

For all regulatory models introduced in Section 3.1, the utility assets, or rate base assets, have been procured under the oversight of the PUC and thus can be presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county. Similarly, all independent power producers' ("IPPs") generation assets are under contract with regulated utilities, and the contract costs are also recovered through electricity rates. Indeed, as the load patterns would in no way be affected by the change in the regulatory model, it is reasonable to expect that all existing assets are needed to ensure continuity of reliable service – at least in the short term.[8]

In this case, since assets remain under a regulated regime, there would not be stranded costs related to the change in regulatory regime under the status quo, status quo with increased oversight, and PBR.[9]

3.2 Regulatory models with potential for unregulated assets

In addition to the COS and PBR models discussed previously, the Project Team introduced two models, the ISO and Distribution-focused, which can result in the deregulation of certain classes of utility assets. Indeed, under these models, the utility can be forced to transfer or divest certain classes of assets, mostly related to generation, to an unregulated subsidiary or the IPP.

- ISO
  An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures reliability and uses bid-based markets to determine economic dispatch for wholesale electric power. Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities should yield their functions of system planning, dispatch, and day-to-day operations to the ISO. Under an ISO model, the incumbent utility can either retain its generation assets or divest them.

- Distribution-focused model
  There are two potential variants under a distribution-focused regulatory model. The first variant is where the distribution system is still owned and operated by the incumbent utilities, which take on a role as Distributed System Platform Providers ("DSPP"). The second variant is where the distribution systems are still owned by the utilities but are operated by an outside Independent Distribution System Operator ("IDSO") entity.

3.2.1 Discussion of potential for stranded costs

While there are currently IPPs operating in various counties of the State of Hawaii, the independently-owned resources are operating under Power Purchase Agreements ("PPA") with the regulated utility. As such, the generation owners are guaranteed the revenues that are specified in the contracts,[10] allowing them to cover fixed and variable costs and earning them a

---

[8] The HECO Companies Power Supply Improvement Plan does lay out a retirement schedule for legacy generation resources as new renewable generation comes online. However, for the purpose of this analysis, the Project Team assumes that the change in regulatory model would not affect the longer-term retirement schedule for existing assets.

[9] There may be stranded costs at the time the assets are retired if not fully depreciated, but they would not be caused by the change in regulatory regime but rather by evolution of generation resource mix.

[10] Subject to performance requirements or other terms and conditions specific to each contract.

return on their investment. In turn, the costs of these PPAs for the utility are recovered through the electricity tariffs paid by consumers.

Conversely, the ISO and distribution-focused models would result in the creation of marketplaces, with the owners of generation earning revenues from offering their resources in the markets and earning the market clearing prices if selected.[11] As with all marketplaces, prices can be volatile, and the outcomes depend on the interaction of several factors such as the types of generation resources participating in the markets, fuel prices, load levels, transmission limits, etc. The key difference, however, is that generation owners can no longer count on the recovery of costs, plus a return on their investments, through regulated rates. Instead, they must ensure that their resources are competitive enough to earn the necessary revenues from the markets.

Should a change in regulatory model require the transfer or divestment of certain classes of utility assets, the transfer price for these assets would need to be agreed upon by both parties to the transaction. This agreement would presumably follow a competitive process where multiple interested parties would bid to purchase the portfolio of utility assets, in part or whole, that is being divested. As discussed in Task 1.1.6., if the assets were to remain under a regulated regime after such a transfer, the acquiring entity would expect to earn a regulated return on its investment similar to the return granted to the incumbent utility by the PUC. As such, the transfer prices would be very close to the book value of those assets. However, in this case, the assets would become unregulated, or "merchant," and earn revenues from the markets. As such the acquiring entity will offer to purchase the assets at a price that allows it, based on the expected magnitude of market revenues, to cover its costs and earn their desired return on investment. The purchase price, therefore, will not be based so much on the book value of the assets, as on their value in a market environment over their assumed remaining economic life.

As discussed in Task 1.1.6., stranded costs arise if the market value of assets the utilities must divest, such as generation resources, is lower than their book value. Indeed, at the time the utility made the investments, it was "promised" a fair return over the life of the assets. However, due to the potential divestiture, and assuming the market value is below the assets' book value, the utility would be prevented from earning that return on its investment. Historically, provided that the investments were prudent and verifiable, utilities have been allowed to recover stranded costs from ratepayers. Therefore, generators would potentially have stranded costs with the change in the regulatory regime to the ISO and distribution-focused models.

On the other hand, the regulatory models considered by the Project Team assume that all transmission and distribution assets would remain under a regulated regime and as such would not be a source of stranded costs for the incumbent utilities should there be a change in regulatory regime.

[11] There are several market design structures that could be implemented, which may or may not include markets for energy, capacity, ancillary services, financial transmission rights, etc.

3.2.2 Methodology for the evaluation of potential stranded costs

As introduced previously, the stranded costs calculation compares the value of the utility's assets in the regulated environment with the value of these same assets in the newly formed regulatory environment. In other terms, the stranded costs are computed as the difference between the current market value of the asset and the historical cost of the asset depreciated through time (i.e., book value). In practice, a certain amount of negotiation also takes place between the utility, regulator, and other stakeholders in order to establish the exact amount of stranded costs allowed to be recovered.

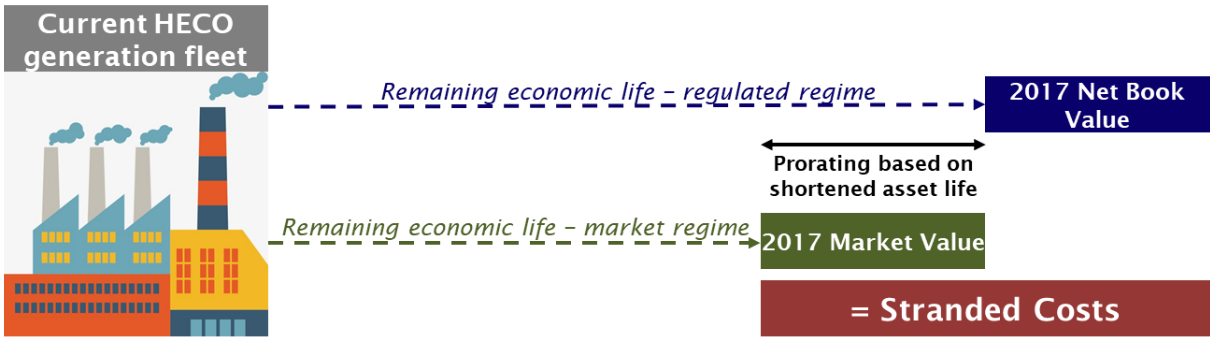
The book value of generation assets for all utilities in the State of Hawaii is disclosed in several regulatory filings such as rate cases and annual reports, as discussed in Task 1.4.1. The market value of these resources, however, can depend on several factors such as the assumed remaining economic life of the assets, competition from other resources, or evaluation of future market conditions.

Under normal circumstances, a well-designed market is structured so that the marginal resource required to ensure the reliability of the transmission system as well as resource adequacy earns enough revenues to cover its going-forward costs. This is true independently of the specific structure of the market, be it an energy and capacity design, or an energy-only design. For purposes of this analysis, the Project Team assumed that the current generation resources in all counties of the State of Hawaii are required for system reliability. Furthermore, in future years some of these resources become superfluous as new generation resources, including renewables, are introduced. These assumptions are based on the HECO Companies' Power Supply Improvement Plan ("PSIP"), which details the reliability requirement for current resources as well as lays out a retirement schedule for legacy resources as new resources come online. It is also possible to draw similar conclusions from KIUC's capital expenditures planning and other long-term planning documents.

In that context, the Project Team assumes that if the counties of the State of Hawaii were to transition to a competitive market structure, these markets would provide sufficient revenues for all current generation resources in the short term in order to ensure reliability. However, in future years, and as the reliability benefit of some older legacy resources disappears, the markets would no longer be able to provide sufficient revenues for those resources to remain online. As such, even though some of these resources would still have a positive book value, their market value to an independent generator would be nil, and they would be retired. The overall market value of these assets, therefore, relies on their remaining economic life, i.e., for how long an independent owner can expect to earn money from these assets.

The methodology for estimating the market value and potential for stranded costs of generation resources adopted by the Project Team therefore hinges on prorating the current book value of assets and comparing its assumed remaining economic life in a regulated regime (based on asset class's average age and depreciation rate) to the assumed remaining economic life in a market regime (based on planned asset retirement date). The approach used by the Project Team is depicted in Figure 3.

Figure 3. Methodology used to estimate stranded costs



3.2.3 Calculation of potential stranded costs

As discussed previously, the entity acquiring assets would value them according to the potential revenues they can generate over their economic life. The economic life represents the length of time an asset can generate revenues. For instance, an asset can become uneconomic following entry of newer resources even though it is not fully depreciated yet.

Using the methodology described in Section 3.2.2, the Project Team estimated the potential stranded costs for utility production assets in the State of Hawaii as illustrated in Figure 1.

3.2.4 HECO

HECO had a total of 1,278 MW of thermal generation capacity in 2017.[12] It has since added Schofield Generating Station ("SGS") to its portfolio. SGS is a 50 MW plant capable of running on a mixture of biofuels and conventional fuels (diesel or oil). If the transition to renewables becomes more aggressive, SGS can transition to operating fully on biodiesel. Therefore, it is expected that the plant will not retire before the forecast horizon (until 2045) and will not result in any stranded costs.

The HECO Companies' response to data requests from the Project Team shows that the gross cost of its production plants as of Q2-2017 was $992.3 million but with a net book value of $634.6 million.[13] Across HECO's generation portfolio, the average undepreciated cost of HECO's generation plants is $532,917/MW as of Q2-2017. The project team used this average figure to estimate the net book value for each generating unit, excluding SGS.

Regulatory filings from HECO's last rate case proceedings show that the average depreciation rate for HECO's production plants was 1.95%,[14] which translates to a book life of 51 years. Based

---

[12] HECO. *About Us – Power Facts.* Web. <https://www.hawaiianelectric.com/about-us/power-facts>

[13] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[14] HECO. *HECO-WP-2505, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2016-0328).* December 16, 2016.

on the ratio of net book value to the gross cost of the plant, 64% of HECO's production assets value remains undepreciated. Thus, the Project Team estimated that the plant assets had, on average, 32 years of remaining asset life.

However, HECO's retirement schedule from the PSIP report shows that most of its assets will be retired long before then. In addition to SGS, only three other units are expected to operate beyond 2045 after being converted to run on biodiesel in 2044. Therefore, the Project Team estimated the market value of each generating unit by multiplying its net book value by the ratio of years before retirement to average years of remaining asset life (32, as discussed above); for units scheduled to run beyond the average remaining asset life, the market value was capped at estimated remaining book value.

Stranded costs for HECO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $321.9 million.

3.2.5 MECO

MECO's thermal generation capacity in 2017 stood at 274 MW.[15] The gross cost of MECO's production plants as of Q2-2017 was $411.8 million but with a net book value of $154.3 million,[16] resulting in an average undepreciated cost of $578,699/MW as of Q2-2017. Regulatory filings from MECO's last rate case proceedings show that the average depreciation rate for MECO's production plants was 2.71%,[17] which translates to a book life of 36 years. Based on the ratio of net book value to the gross cost of the plant, 37% of MECO's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 13 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for MECO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $11.3 million.

3.2.6 HELCO

HELCO had a total generating capacity of 187.8 MW in 2017, of which 183.3 MW was thermal, and 4.5 MW was hydro capacity.[18] The Project Team assumed that the market value of the hydro plants would be the same as its book value since it will not face any regulatory risks of early retirement going forward. The gross cost of HELCO's production plants as of Q2-2017 was $327.5

---

[15] MECO. *About Us – Power Facts.* Web. <https://www.mauielectric.com/about-us/power-facts>

[16] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[17] MECO. *MECO-1703, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2017-0150).* October 12, 2017.

[18] HELCO. *About Us – Power Facts.* Web. <https://www.hawaiielectriclight.com/about-us/power-facts>

million but with a net book value of $139.3 million,[19] resulting in an average undepreciated cost of $749,266/MW. The average depreciation rate for HELCO's production plants was 2.52%,[20] which translates to a book life of 39 years. Based on the ratio of net book value to the gross cost of the plant, 43% of HELCO's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 16 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for HELCO's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $12.5 million.

3.2.7 KIUC

The Project Team's analysis of KIUC's generation asset excludes the solar projects developed by the utility under Special Purpose Vehicle ("SPV") ownership, treating the SPV as an IPP. KIUC's total generating capacity stood at 125.3 MW at the end of 2016, of which 124 MW was thermal, and 1.3 MW was hydro capacity.[21] Again, the Project Team assumed that the market value of the hydro plants would be the same as its book value since it will not face any regulatory risks going forward. The gross cost of KIUC's production plants as of Q4-2016 was $152.1 million but with a net book value of $76.0 million,[22] resulting in an average undepreciated cost of $645,695/MW. The average depreciation rate for KIUC's production plants was 2.99%,[23] which translates to a book life of 33 years. Based on the ratio of net book value to the gross cost of the plant, 50% of KIUC's production assets remains undepreciated. Thus, the Project Team estimated that the plants had, on average, 16 years of remaining asset life.

The Project Team estimated the market value of generation assets using the same approach described for HECO in Section 3.2.4. Stranded costs for KIUC's generation portfolio, calculated by subtracting estimated market value from net book value, was estimated at $31.9 million.

3.2.8 Factors that can affect the magnitude of stranded costs

The Project Team's estimates of stranded costs are based on several assumptions, as described in Section 3.2.2. These assumptions are intended to provide a base case to estimate stranded costs. In reality, the actual magnitude of stranded costs may differ due to factors for which sufficient data is not available to include in the model. Some of these factors are discussed below.

---

[19] HECO. *Response to LEI data request. Exhibit 1b – Plant Information @ Q2-2017.*

[20] HELCO. *HELCO-1603, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2015-0170).* September 19, 2016.

[21] KIUC. *About Us – Energy Information.* Web. <http://website.kiuc.coop/content/energy-information>

[22] KIUC. *Annual Financial Report to the PUC 2016.*

[23] KIUC. *KIUC Depreciation Study.*

1. Market risk vs. regulatory certainty

   The inclusion of generation in the incumbent utilities' regulated asset base allows the utilities to earn a return (for the HECO Companies) or at least cover their operating costs in case of KIUC. This holds true regardless of the amount of new generation capacity procured from IPPs if the utilities deem the asset to be necessary for reliability. A competitive environment changes this dynamic over the medium- to long-term. Thermal plants that are currently necessary for reliability may not be required due to the entry of new firm generation assets into the market. This is particularly true of thermal plants since they are vulnerable to fuel price shocks.

   The estimates of stranded costs in Section 3.2.2 depends on the assumption that the generating units will not retire before their intended retirement date as forecast by the incumbent utilities. If prospective buyers are disinclined to take a longer-term view, it reduces the market value of the assets and correspondingly increases the stranded costs. For instance, the Project Team's methodology assumes that there will be no stranded costs for a generating unit scheduled to operate through at least 2045 because the unit would be fully depreciated by then (assuming no capex upgrades to the unit). However, a buyer may be willing only to pay a price based on the assumption that the unit operates through 2030, resulting in stranded costs for the undepreciated portion of assets as of that year. Figure 4 indicates how the stranded costs for each utility increase as the time horizon of the buyer is shortened, where 100 years represents the assets remaining operational until their current retirement schedule.

Figure 4. Stranded costs - time horizon sensitivities

	Years			
Stranded costs ($000s)	**100**	**20**	**15**	**10**
HECO	321,852	364,878	388,518	446,970
HELCO	12,513	12,513	18,699	52,467
MECO	11,333	11,333	11,333	42,757
KIUC	31,926	31,926	37,293	42,660

Source: Project Team analysis.

2. Higher cost of equity higher for merchant than regulated entities

   The analysis above does not account for the differences in costs of capital for prospective buyers vs. the incumbent utilities once the regulated assets become merchant generation. Equity investors are willing to finance regulated assets at more favorable rates due to greater certainty of returns. Therefore, the higher the required rate of return sought by a prospective buyer's equity investors, the lower the price it would be willing to pay for the current utility assets, resulting in higher stranded costs.

3. Buyers having more bearish views on market conditions

   Buyers of current utility generation assets may also have different views on how Hawaii's power sector will evolve, especially with increased competition. Compared to forecasts by the incumbent utilities, their market outlook could be more pessimistic – faster growth in DERs (including demand response and energy efficiency), slower load growth, more rapid declines in costs of renewables and storage, and higher fuel prices in the future. Market values of current utility generation would then be lower with higher stranded costs.

4. Single asset vs. portfolio purchase

   The Project Team's analysis is based on a portfolio view of each utility's generation assets. The market value for each generation unit is estimated using a portfolio-wide average book life and net book value per MW. This approach may result in very different stranded cost estimates. Older plants may have lower market values than estimated using the Project Team's approach, but they are also more likely to have low book values remaining. Newer plants may be more desirable for buyers but whether they will be desirable enough for the market price to cover their book value is uncertain.

4 Appendix A: Scope of work to which this deliverable responds

Task 2.2.4 **Summary analysis and conclusions related to estimating stranded costs for each regulatory model.** CONTRACTOR shall identify and estimate the impact of any potential stranded assets as a result of change in regulatory model.

DELIVERABLE FOR TASK 2.2.4. CONTRACTOR shall provide its conclusions and all work related to estimating stranded costs for each regulatory model. CONTRACTOR shall consider the economic value of these assets and whether these assets are needed under a given regulatory model in order to estimate the total magnitude of potential stranded costs. CONTRACTOR shall provide a summary of analysis and conclusions of this research in MS Excel and PowerPoint. CONTRACTOR shall submit deliverable for TASK 2.2.4 to the STATE for approval.

5 Appendix B: List of works consulted

Federal Energy Regulatory Commission. "Order No. 888 Final Rule". Docket No. RM95-8-000 & Docket No. RM94-7-001. April 24, 1996.

Federal Energy Regulatory Commission. "Initial Decision on Recovery of Stranded Costs". Docket No. SC97-2-000. Issued June 25, 1998.

Filsinger Energy Partners. "Evaluation of Alternative Ownership Options for Electric Utility Assets on the Islands of Oahu and Hawaii". April 2016.

Hawaiian Electric Company. *HECO-WP-2505, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2016-0328)*. December 16, 2016.

Hawaiian Electric Company. "Rates & Regulations – Average Price of Electricity". Web. Accessed August 7, 2017. <https://www.hawaiianelectric.com/my-account/rates-and-regulations/average-price-of-electricity>

Hawaii Electric, Maui Electric, and Hawaii Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. PUC Docket 2014-0183. Book 1. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_Companies_PSIP_update_report_1_of_4.pdf>

Hawaii Electric, Maui Electric, and Hawaii Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. PUC Docket 2014-0183. Book 2. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_Companies_PSIP_update_report_2_of_4.pdf>

Hawaii Electric, Maui Electric, and Hawaii Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. PUC Docket 2014-0183. Book 3. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_Companies_PSIP_update_report_3_of_4.pdf>

Hawaii Electric, Maui Electric, and Hawaii Electric Light ("HEI"). *PSIP Update Report*. December 23, 2016. PUC Docket 2014-0183. Book 4. <https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_Companies_PSIP_update_report_4_of_4.pdf>

Hawaii Electric Light. *HELCO-1603, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2015-0170)*. September 19, 2016.

Kauai Island Utility Cooperative. "Rates". Web. Accessed August 7, 2017. <http://website.kiuc.coop/content/rates>

KIUC. *Annual Financial Report to the PUC 2016.* March 28, 2017.

Maui Electric. *MECO-1703, Application for Approval of General Rate Case and Revised Rate Schedules and Rules (Docket No. 2017-0150)*. October 12, 2017.

Stakeholder Workshop Summary: Regulatory Models

prepared for DBEDT by London Economics International LLC and Meister Consultants Group

September 28, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("MCG"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This Stakeholder Workshop Summary for the Utility Regulatory Stakeholder Workshops is responsive to Task 2.2.5 which includes the preparation of an outreach plan to solicit public input from each island currently served by an electric utility on the results of Tasks 2.1.1 through 2.2.4 as well as this report to document the results of the Stakeholder Outreach. This memo provides a summary of the stakeholder workshop conducted on June 12 through 22, 2018 on Hawaii, Kauai, Lanai, Maui, Molokai, and Oahu.

Table of Contents

Table of Figures

List of acronyms

B-Corp	B-corporation
Co-op	Cooperative Utility
DBEDT	Department of Business, Economic Development & Tourism
DER	Distributed Energy Resource
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
GHG	Greenhouse Gas
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International
LMI	Low- or Moderate-Income
MCG	Meister Consultants Group
MECO	Maui Electric Company
NERC	North American Electric Reliability Corporation

Performance-Based Regulation

PBR	Performance Incentive Mechanism
PIM	Power Purchase Agreement
PPA	Public Utilities Commission
PUC	Photovoltaics
PV	Request for Proposals
RFP	Renewable Portfolio Standard
RPS	Regional Transmission Organization
RTO	

1 Executive Summary

1.1 Background

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI") and Meister Consultants Group ("MCG," collectively "the Project Team") were contracted to perform this study.

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria:

- achieve state energy goals;
- maximize consumer cost savings;
- enable a competitive distributions system; and
- eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of:

- increasing local control over energy sources serving each county;
- ability to diversify energy resources;
- economic development;
- reducing greenhouse gas emissions;
- increasing system reliability and power quality; and
- lowering costs to all consumers.

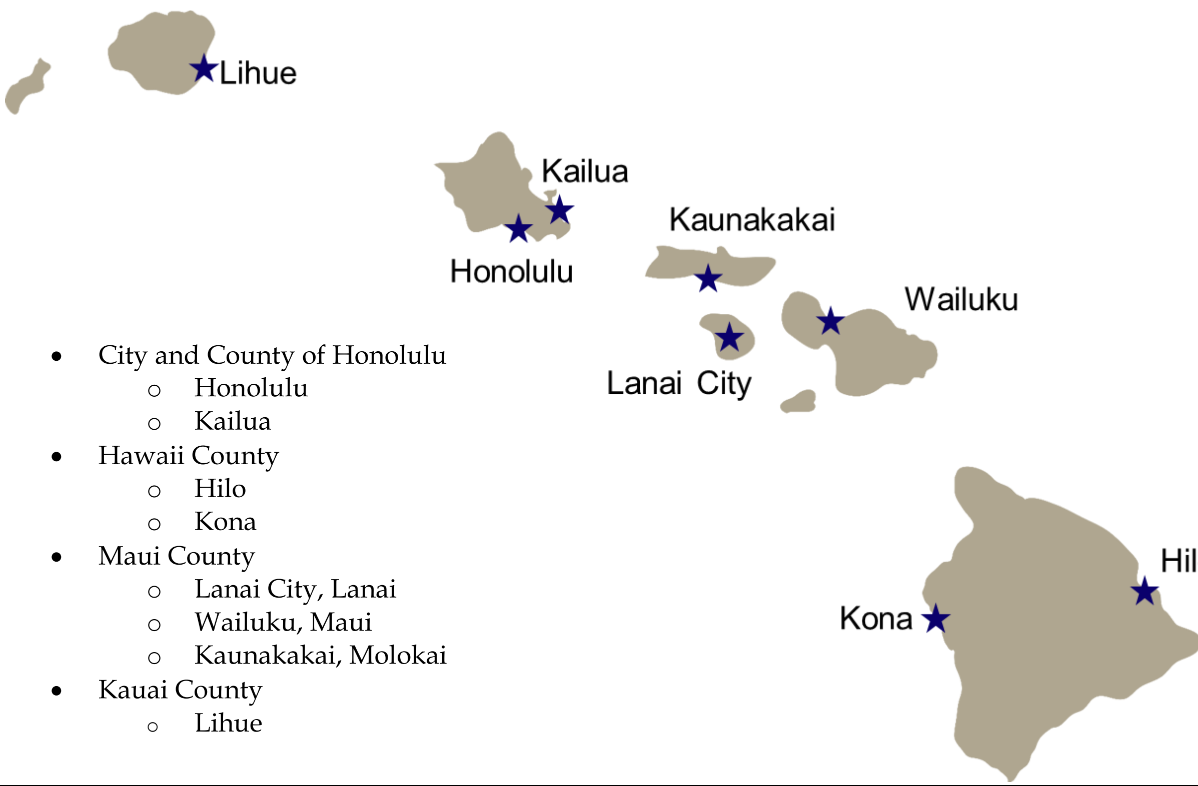
This report, the Stakeholder Workshop Summary: Utility Regulatory Models, has been prepared to fulfill requirements under Task 2.2.5 in the project scope of work and provides a summary of the stakeholder workshops conducted on each island between June 12th and June 22nd, 2018.

The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. Nevertheless, we want to note that the survey of the public has never been suggested to be a statistically valid sampling of the population. An e-mail address, DBEDT.UtilityBizModStudy@hawaii.gov, has been set up to collect feedback over the course of the project. All feedback related to the regulatory model analysis that is received by August 31st, 2018 were summarized and added to this report. All other feedback will be incorporated into future reports submitted under this project.

1.2 Utility Regulatory Model Stakeholder Workshops

The Stakeholder Workshops for the Utility Regulatory Models were completed between June 13, 2018, and June 22, 2018. There were eight (8) public workshops held at each location shown in Figure 1. Additionally, the project team conducted a workshop at the VERGE conference in Honolulu on June 12th, 2018.

Figure 1. Location of the meetings



- City and County of Honolulu
  - Honolulu
  - Kailua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

The objectives of the workshops were to provide stakeholders with information regarding the various regulatory models under consideration, to receive their input on the priorities for regulation of the electric sector, and input on the advantages and disadvantages of different regulatory models in meeting community priorities. Combined, 75 stakeholders participated in the public workshops, and more than 100 participated in the workshop at VERGE.[1]

In addition to the workshops, the Project Team has conducted multiple bilateral meetings as part of the ongoing stakeholder engagement process. Between June 12th and June 22nd, the Project Team met with 20 energy industry, government, non-profit, and other stakeholders from across the state and received input that varied from support for Performance-Based Regulation ("PBR") implementation, to interest in only minor revisions to the status quo, to concern for unintended

[1] The majority of participants at VERGE did not sign in.

consequences due to the difficulties in designing PBR well, to support for lighter regulation of cooperative utilities ("co-ops").

1.3 Key findings from workshops

While the discussions at each workshop were unique as stakeholders expressed their priorities and concerns, there were some themes that came up multiple times during the two weeks, namely:

- reliable electricity is a priority, and the current regulatory model has been successful at ensuring utilities provide reliable service;
- minimizing rates now and in the future is a priority;
- that stakeholders greatly value the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs;
- there is much interest in improving resiliency in the electrical grid across the state, particularly in relation to severe storms;
- there is demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation;
- the regulatory model must allow for and encourage innovation so that the utility can meet its goals most cost-effectively;
- there is concern that the current regulatory model does not allow for the competition in generation necessary for generation to be developed in the most cost-effective way; and
- that any model must consider the equity of costs and access to renewable resources as there is concern that grid defection is impacting the Low or Moderate-Income ("LMI") community the most.

1.4 Status Quo

All stakeholders agreed that the current regulatory model results in the provision of reliable electricity to the state. There was general concern in relation to the HECO Company utilities[2], however, that the status quo does not encourage the utilities to invest sufficiently in improving grid resiliency. Across the state, stakeholders believed that this model has not been successful in minimizing electric rates. Many stakeholders expressed dismay over the lack of community involvement in the utility decision-making process required under the status quo and expressed that the utility is not incentivized to take action or make investments in line with community priorities. Some stakeholders suggested that increasing representation from each island on the Public Utilities Commission ("PUC") would be a good first step to ensuring that priorities from each island are addressed. Some stakeholders explained that this model does not allow sufficient access to the grid for independent power producers ("IPPs") and does not sufficiently incentivize

[2] The HECO Company utilities include Hawaiian Electric Company ("HECO"), Hawaii Electric Light Company ("HELCO"), and Maui Electric Company ("MECO"). Hawaiian Electric Industries ("HEI") is the parent company for these three utilities. The term "HECO Companies" is used throughout this report when referring to all three together.

investments in renewables. Overwhelmingly, stakeholders discussed that the PUC does not have sufficient resources to handle its current tasks.

1.5 Hawaii Electricity Reliability Administrator ("HERA")

In general, stakeholders did not think that HERA would be a good solution for Hawaii. While many noted that it might increase grid access and increase deployment of renewables, a majority of stakeholders thought that HERA would be redundant, since the PUC already assumes much of the role HERA would be playing, and increase overall costs.

1.6 Independent System Operator ("ISO")

Though it was recognized that an ISO would increase competition, stakeholders agreed that it would be too costly and that the market is too small in Hawaii for an ISO to work.

1.7 Distributed System Platform Provider ("DSPP")

Stakeholder opinions varied greatly regarding a DSPP model. While many explained that this model would not work in Hawaii, others saw it as a way to increase competition and deployment of distributed energy resources ("DERs"). Many stakeholders mentioned that the costs would be too high, particularly the necessary up-front investments required to implement this model.

1.8 PBR

Stakeholders were supportive of using incentives under a PBR framework to encourage utilities to make investments and take actions that are in line with community and policy goals. The potential metrics discussed significantly varied and included cost stabilization, cost equity, increased renewable generation, incorporation of community priorities, the reliability of service, and grid resiliency. Multiple stakeholders suggested that it would be critical for representatives from each island to be involved in designing the metrics. There was general agreement that linking utility revenues to performance would be beneficial.

Many stakeholders highlighted that it would be difficult to design and implement PBR well and there was substantial concern about unintended consequences that would result if it is not designed well. As a result, some stakeholders explained that it might be too risky. Preferences varied from a PBR model that would create minor adjustments to the status quo to one that would result in a significant overhaul of the system.

1.9 Lighter Regulation of Co-ops

There was broad support for lighter regulation of co-ops, mainly from stakeholders on Kauai. Many stakeholders said that the Kauai Island Utility Cooperative ("KIUC") has demonstrated the ability to manage and operate the utility well and that PUC regulations are unnecessary. Some stakeholders suggested that Hawaii follow the example on the mainland where co-ops are not regulated as heavily as investor-owned utilities ("IOUs"). Stakeholders on Kauai noted that a reduction in regulations would reduce costs for both KIUC and the PUC.

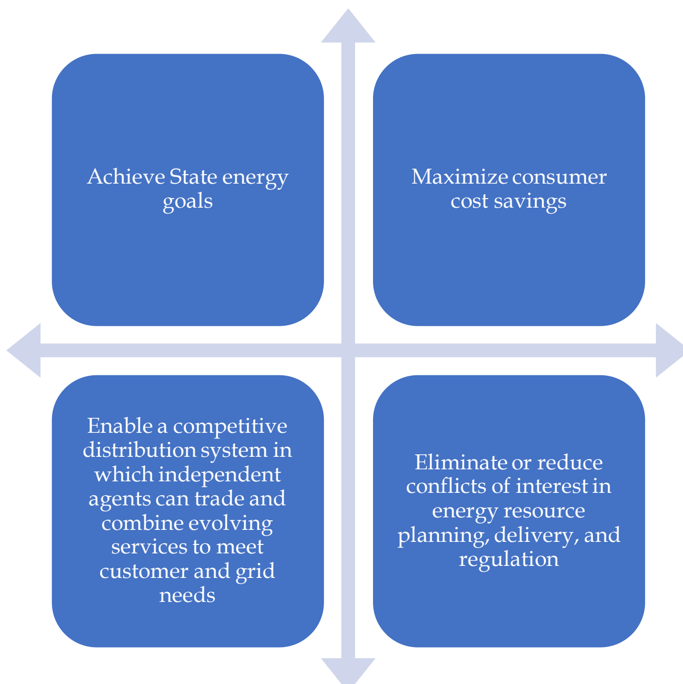
2 Introduction and scope

2.1 Project description

DBEDT was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI and MCG, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 2.

Figure 2. State's key criteria



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models and determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy

---

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable has been prepared to fulfill requirements under Task 2.2.5 in the project scope of work. Task 2.2.5 requires the Project Team to prepare a report documenting the public outreach. Comments received from the workshops will be analyzed and considered as we conduct the other tasks under this project, namely:

- Task 2.2.6. - Ranking process and rationale for the recommendation of three feasible utility regulatory models;

- Task 2.3.1. - Identification of various steps, timeline, and costs required to change from the current regulatory model to new models, including necessary approvals;

- Task 2.3.3. - Identification of risk for each regulatory model, analysis of each risk, and assessment of the overall risk profile for each regulatory option;

- Task 2.3.4 – Assessment of the potential impact of different models on state agencies and specific stakeholders, including the PUC and consumer advocate; and

- Task 2.5.5. - Identification of funding mechanisms for each regulatory model and the potential cost implications for customers.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Stakeholder Engagement Overview

3.1 Objectives

Throughout the project, the Project Team is meeting with stakeholders representing interests across the economy from each island to both receive their input on what the utilities' role is in achieving state policy goals and providing interim and final results of the analyses. The broad objectives are to:

- introduce the public to this project and provide multiple pathways for public input;
- provide information to support the public's understanding of the differences between and trade-offs of multiple utility ownership and regulatory models; and
- provide information on possible approaches for Hawaii to best achieve the state's clean energy and other policy goals.

There are two groups of stakeholders: the Core Group and the Public Group. The Project Team convened a Core Group of stakeholders including representatives from the organizations listed below on September 22, 2017, and October 13, 2017.

Figure 3. Core Group

Public Sector	County Energy Coordinators	County Economic Development Boards	Utilities
o DBEDT o Consumer Advocate o Public Utilities Commission ("PUC")	• Hawaii • Honolulu • Maui • Kauai	• Hawaii • Honolulu • Maui • Kauai	o Hawaiian Electric Company ("HECO") o Hawaiian Electric Light Company ("HELCO") o Kauai Island Utility Cooperative ("KIUC") o Maui Electric Company ("MECO")

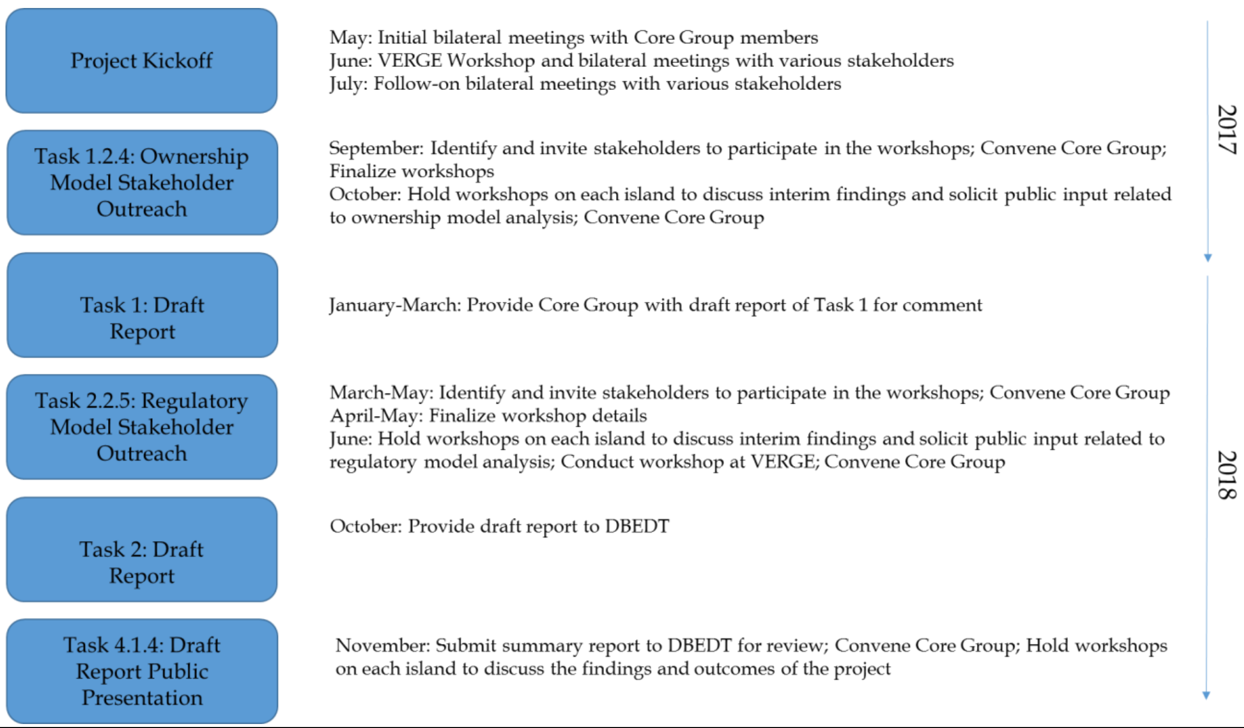
The Project Team will continue to engage with the Core Group multiple times throughout the project to solicit their input on the process for stakeholder engagement, the stakeholders with whom to meet and to comment on interim and final analyses. These meetings will take the form of a conference call, to be coordinated and scheduled by the Project Team. The proposed timing for convening the Core Group is outlined in Figure 4 below.

The Public Group is open to any parties interested in this project's scope. Therefore, the Public Group will include representatives from the general public, state and county institutions, non-profits, the private sector, academia, and the federal government (primarily the U.S. Department of Defense and U.S. Department of Energy).

3.2 Timeline

Over the span of the project, the team will actively engage with stakeholders at multiple points and will be open to additional discussions as requested by stakeholders. The figure below illustrates a high-level timeline of the stakeholder engagement opportunities that are currently planned, broken out by the task. While target months are provided for all activities, these are subject to change as the timeline of the broader project evolves.

Figure 4. Indicative Timeline for Stakeholder Engagement



4 Stakeholder Engagement: Utility Regulatory Models

For Task 2.2.5, the team conducted stakeholder workshops on each island served by an electric utility and led a workshop at the VERGE conference in Honolulu. The Stakeholder Outreach Plan, which was submitted to DBEDT on April 4, 2018, provided a detailed discussion of the stakeholder engagement process conducted for this task. This section provides a summary of the process and documentation of the discussions on each island.

4.1 Objective and Scope

The primary goals of the Utility Regulatory workshops were to:

- solicit public input on the topic of utility regulatory models from stakeholders on each island;
- create opportunities for everyone to share his/her opinion on Hawaii's utility regulatory model;
- provide a high-level discussion of the different regulatory models identified by the Project Team;
- provide clear, easy to understand and objective information on the differences between utility regulatory models; and
- provide clear information on the next steps that the team will be taking and future opportunities for stakeholders to participate or provide feedback.

The Project Team anticipated that the participants would have a varied knowledge of the energy sector and utility regulatory models, ranging from the general public with a more basic understanding of the sector to experts in the field. As such, the public workshops were designed to be high level and focus on building a common understanding of definitions and terms, the trade-offs between different utility regulatory models, and developing an understanding of what the community sees as the role of regulation, based on the analysis conducted for this project. The VERGE workshop included more technical discussions as the audience was expected to have more familiarity with the energy sector.

Additionally, the number of participants was expected to vary greatly by island. As such, the breakout sessions were designed and selected based on approaches that work well for the number of participants at each workshop.

4.2 Administration of Workshops

4.2.1 Workshop Administration

The community workshops were administered and facilitated by the Project Team members, with one Project Team member designated as the lead facilitator. The DBEDT representatives provided welcoming and concluding remarks, and otherwise observed or responded to questions as needed. The VERGE workshop was facilitated by the Project Team with support from DBEDT staff for facilitating small group discussions. There were between three and four Project Team members at each workshop. The workshops were completed over a two week period, divided among two teams of facilitators:

Team 1:

- Lead Facilitator: Ryan Cook
- Facilitator: AJ Goulding
- Facilitator: Gabriel Roumy
- Facilitator: Tianying Lan

Team 2:

- Lead facilitator: Ryan Cook
- Facilitator: Sarah Booth

- Facilitator: Len Trinidad
- Facilitator: Tianying Lan

4.2.2 Workshop Agenda

4.2.2.1 Community Workshops

The workshops in Kailua, Lihue, Hilo, and Kona were scheduled from 5:30 pm - 7:00 pm and the workshops in Honolulu, Wailuku, Kaunakakai, and Lanai City were scheduled from 6:00 pm - 7:00 pm. All workshops followed the agenda provided in Figure 5, with the timing shifted a half an hour later for the workshops which began at 6:00 pm.

Figure 5. Workshop Agenda

Time	Topic Addressed	Overview
5:30pm to 5:40pm	Welcome and project introduction	• DBEDT provides a brief welcome to the project and introduces LEI • If there is a small enough group, LEI asks attendees to introduce themselves – in large meetings this will happen in small groups • LEI provides an overview of the project purpose and timeline, and the goal of today's session
5:40pm to 6:10pm	Regulatory Model Overview and PBR Detail	• LEI provides an overview of each regulatory model considered and provides detail on PBR • LEI asks if there are clarifying questions (asking the group to hold opinions on models for the small group discussion)
6:10pm to 6:30pm	Large Group Facilitation	• LEI introduces MCG • MCG walks through large-group facilitation sessions on priorities, and thoughts on what's working well and what could be improved • If the group is very large, this may be split into two groups
6:30pm to 7:00pm	Small Group Facilitated Discussion	• MCG provides an overview of the facilitated session and divides the group into an appropriate number of small groups • At each table, facilitator conducts small group session and records notes
7:00pm to 7:05pm	Report Out, Next Steps, Close	• MCG reconvenes group as a whole • Each facilitator comes to the front and provides a 1-2 minute overview of the highlights of their group's discussion • LEI provides an overview of next steps and ways to stay engaged and notes that staff will stay in the room for continued discussion until 7:30 • DBEDT thanks the audience for attending and closes the session

4.2.2.2 VERGE Workshop

The VERGE workshop was held on June 12th from 8:30 am – 12:30 pm. The workshop followed the agenda in Figure 6.

Figure 6. VERGE Workshop Agenda

Time	Topic Addressed	Overview
8:30am to 8:40am	Arrival time	• Time for participants to take their seats and allow for late arrivals • Invite participants to sign-in as they arrive
8:40 am to 8:50 am	Welcome and project introduction	• DBEDT provides a brief welcome to the project and introduces the team • LEI provides an overview of the project purpose and timeline, and the goal of today's session
8:50am to 9:20am	Regulatory Model Overview and PBR Detail	• LEI provides an overview of each regulatory model considered, and discusses PBR in more detail • No Q&A at this point
9:20am to 10:30am	Panel Discussion on Regulation and PBR Specifically	15 Min - Intros • LEI introduces MCG • MCG introduces panelists, who seat themselves at the front. • Each panelist, in turn, provides a 2-5 min introduction of their view on the topic 40 Min – Moderated Panel • MCG moderates panel discussion 20 Min – Audience Q&A • Audience Q&A to the panel
10:30am to 10:45am	Break	• At end of the panel, MCG releases audience for a brief break, asks to reconvene at their tables afterward
10:45am to 11:55am	Small Group Facilitated Discussion	• MCG provides an overview of the facilitated session to full audience and releases group to small tables • At each table, facilitator conducts small group session and records notes

Time	Topic Addressed	Overview
11:55am to 12:05pm	Next Steps, Close	• MCG reconvenes group as a whole • LEI provides an overview of next steps and ways to stay engaged and notes that staff will stay in the room for continued discussion until 12:30 • DBEDT thanks the audience for attending and closes the session

4.2.3 Materials Provided to Participants

All participants at the community and VERGE workshops were provided with a worksheet containing a summary of regulatory models being analyzed for this project. The worksheet is listed in Appendix A beginning on page 65.

4.3 Workshop Content

4.3.1 Team Presentations

The Project Team provided overview slides that were used all, or in part, at all meetings. The slides, which are available at https://energy.hawaii.gov/utility-model, provided:

- an overview of the project;
- a discussion of the current role of the PUC and the utilities' activities in the generation and supply of electricity;
- a high-level presentation of the characteristics, pros, and cons of the different utility regulatory models being analyzed for this project; and
- information on future opportunities for stakeholders to participate and provide input.

4.3.2 Format for Stakeholder Discussions

There were two main sections of the community workshops focused on stakeholder discussions:

1. Large Group Discussion on Regulatory Priorities
2. Small Group Discussion on Regulatory Models

The Large Group Discussion was facilitated by one of the team's facilitators who asked the participants to talk about their priorities for utility regulation, how regulation is working well, and areas for improvement in the regulatory model. The comments were written down on note cards and arranged thematically, either on a pinboard or table.

The Small Group Discussion focused on discussing the benefits and drawbacks of the various regulatory models, as well as the challenges to transitioning to different models. For workshops with more than 15 participants, the participants broke into smaller groups for this discussion.[7] All discussions were facilitated by a Project Team member to ensure the conversations stayed productive and relevant, and that all participants were given the opportunity to speak if they desired to do so.

VERGE was organized differently and included a panel discussion with time for audience questions and facilitated discussions with the large group as a whole followed by facilitated discussions in smaller groups.

4.4 Stakeholder Workshop Schedule

Figure 7 lists the date, location, and venue of each of the stakeholder workshops. Team 1 held two meetings on Oahu and one on Kauai. Team 2 held one meeting on Maui, Molokai, Lanai, and two on the Island of Hawaii. In addition to the community workshops, Team 1 conducted the workshop at the VERGE conference.

Figure 7. Stakeholder Workshop Schedule

Team 1			
	Island	**Town**	**Venue**
12-Jun	Oahu	Honolulu	VERGE
13-Jun	Oahu	Kailua	Enchanted Lake Elementary School
14-Jun	Oahu	Honolulu	Hawaii Foreign-Trade Zone No. 9
15-Jun	Kauai	Lihue	Kauai High School
Team 2			
	Island	**Town**	**Venue**
18-Jun	Maui	Wailuku	Waikapu Community Center
19-Jun	Molokai	Kaunakakai	Mitchell Pauole Main Hall
20-Jun	Lanai	Lanai City	Lanai Community Center
21-Jun	Hawaii	Hilo	Waiakea High School
22-Jun	Hawaii	Kona	Natural Energy Laboratory of Hawaii Authority

[7] The number of small group breakouts was determined based on the number of participants. For Honolulu, Kailua, Wailuku, Kaunakakai, Lanai City, Hilo, and Kona there was one group discussion. For Lihue there were two small groups.

4.5 Outreach for Stakeholder Workshops

To announce the workshops and invite stakeholders, the Project Team supported DBEDT's outreach efforts. DBEDT conducted outreach through four primary channels:

1. Press release to media contacts
2. Email invitation to stakeholders
3. Discussion with the Core Group
4. Outreach through the Hawaii State Energy Office ("HSEO") website and social media outlets

In addition, outreach was conducted through the promotion of the VERGE conference, and the project team promoted community-level events as part of the VERGE workshops.

The Project Team prepared flyers that were used to announce the workshops (Appendix B: Outreach Flyers). Email invitations were sent to more than 1,900 stakeholders on April 16, 2018 and May 21, 2018 (Appendix D: Email Invitation Text). The stakeholders that received email invitations were identified in discussion with DBEDT, the Core Group, bilateral meetings with stakeholders in Hawaii, through interactions at VERGE, through previous interaction with the project team for this project, and through the Hawaii Clean Energy Initiative ("HCEI"). The invitations provided a summary of the workshop goals and a link to the flyers where participants could sign-up for the event. Additionally, the Project Team provided the Core Group members with the logistics for the meetings on each island and requested that they share the information with their contacts and networks as appropriate. DBEDT also posted the information on its Facebook page and Twitter feed.

4.6 Workshop Participants

The workshops were attended by stakeholders representing county organizations, state organizations, utilities, non-profits/community groups, academia, local and state elected officials, and the private sector. There were 75 participants at the 8 stakeholder workshops and more than 100 stakeholders at the VERGE workshop (see

Figure 8 and Figure 9 for details).[8] Stakeholders that were unable to attend have been encouraged to submit feedback to DBEDT.utilitybizmodstudy@hawaii.gov. Feedback will be collected over the course of the project.[9] At the county level, workshop participation ranged from 10 in Hawaii County to 30 in Maui County.

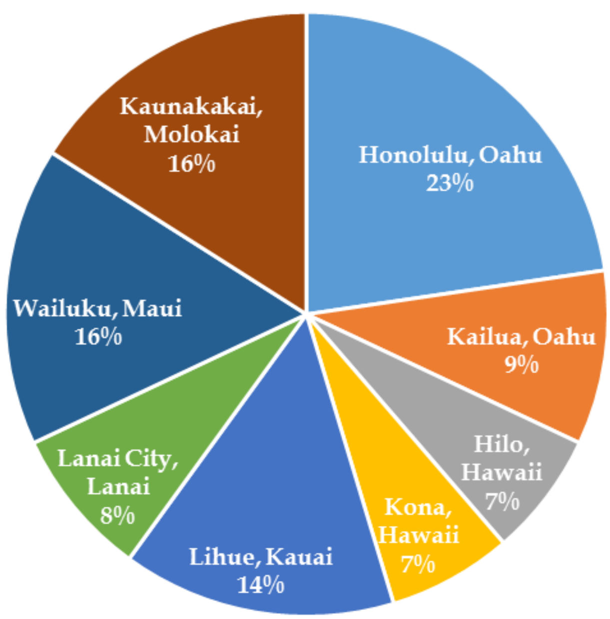
[8] There is some double-counting as a few people attended both VERGE and a workshop and few attended multiple workshops.

[9] Feedback received at this email is not included in this report. Feedback received through August 31st, 2018 will be summarized in an addendum to this report. Feedback received after August 31st will be incorporated into future reports for this project.

Figure 8. Workshop Participation

County (Town, Island)	Participants
City and County of Honolulu	24
Honolulu, Oahu	17
Kailua, Oahu	7
Hawaii County	10
Hilo, Hawaii	5
Kona, Hawaii	5
Kauai County (Lihue)	11
Maui County	30
Lanai City, Lanai	6
Wailuku, Maui	12
Kaunakakai, Molokai	12
Total	75

Figure 9. Percentage of Total Participants at each Workshop



5 Stakeholder Discussions

A significant portion of each workshop focused on facilitated stakeholder discussions to receive input from participants on their priorities for electric utility regulation and the advantages and disadvantages of different regulatory models in achieving the community's priorities. The following sections provide a summary of the discussions from each workshop. A high-level overview of the discussions is presented in Figure 10, Figure 11, Figure 12, Figure 13, and Figure 14. There were often differences of opinions among stakeholders at each workshop, and these summary tables are not meant to imply a consensus of the stakeholders present nor of the community in its entirety.

Figure 10. Summary Table of Workshop Discussions: City and County of Honolulu

Location	*Top Priorities*	*Discussion Highlights by Regulatory Model*		
		Status Quo	**PBR**	**Other Models**
Honolulu	Resiliency and reliability Renewables, including DERs Innovation and new technology adoption Affordability	Ensures reliable electricity Rates are too high Improvements needed for resiliency Does not provide sufficient access to the grid for renewables or IPPs Does not incentivize the utility to make the best investments for the system	Incentivizes utility to take actions in line with ratepayer and policy goals Encourages flexibility Complicated and difficult to design well High potential for unintended consequences	HERA could increase accountability, grid access, and reliability but may be redundant ISO would increase competition, but the market is too small Uncertain about how DSPP model would work
Kailua	Increasing renewables Competition in generation	Ensures reliable electricity Has resulted in major energy efficiency improvements Incentivizes the utility to make capital investments Does not sufficiently incentivize investment in renewables	Incentivizes more efficient utility operations May be too risky for utility	DSPP model would create competition and opportunities for renewables ISO would increase competition but may be too risky Supportive of reduced regulation of KIUC

Figure 11. Summary Table of Workshop Discussions: Hawaii County

Location	*Top Priorities*	*Discussion Highlights by Regulatory Model* Status Quo	 PBR	 Other Models
Hilo	Reducing rates and considering equity issues Increasing renewables Grid flexibility and resiliency Market competition should drive investments, not policy	Reliable electricity Too driven by politics instead of market Ratemaking process is too complicated for individuals to understand Needs more local representation on PUC	Metrics seen as a good way to align utility actions with community goals Prefer incentives to penalties Metrics could include equity, load stability (mitigate grid defection), and cost stabilization	Need the flexibility to allow for changing technologies Different models may work on different islands Any model must consider impacts on LMI community ISO and DSPP models would not work
Kona	Resiliency Increasing renewables Flexibility to adopt new technologies Responsive to customer needs	Supply and demand is well balanced Utility is not responsive to community Inflexible which inhibits adoption of new technologies PUC is too cautious and favors the utility in decisions	Increases the link between utility revenues and performance Metrics with specific timelines would be useful Metrics could include renewable generation and diversity of renewables	Regulation should protect the public interest, not increase business costs nor stifle innovation Too complex of a model will be too complicated to manage HERA could increase renewables and improve access to the grid for non-utility players but may be redundant DSPP may be the only functional model in 5 years as DERs increase

Figure 12. Summary Table of Workshop Discussions: Kauai County[10]

Location	Top Priorities	Status Quo	Lighter Regulation for Co-ops	Other Models
		Discussion Highlights by Regulatory Model		
Lihue	Not discussed	Reliable electricity PUC is overburdened Current regulation is costly and cumbersome for KIUC, particularly rate cases	Co-ops are not regulated as heavily on the mainland KIUC is more responsive to customers than PUC PUC could provide dispute resolution, but there are already options for this (elections, member votes) Lighter regulation would reduce costs for the PUC	HERA and ISO would not work DSPP would be too costly

[10] The discussion at the Kauai Workshop focused primarily on lighter regulation for co-ops, with no discussion of stakeholder priorities in general or of PBR implementation since KIUC is exempted from the PBR docket.

Figure 13. Summary Table of Workshop Discussions: Maui County

Location	Top Priorities	Discussion Highlights by Regulatory Model: Status Quo	PBR	Other Models
Lanai	Responsiveness to community needs Minimizing rates Increasing incentives for residential and businesses to deploy renewables	Reliable electricity MECO maintains a strong relationship with the community Does not incorporate community priorities	Metrics would ensure community needs are incorporated Prefer modification of status quo to radical change Metrics could include efficiency, rate costs, reliability, transmission and distribution upgrades, power restoration after the outage, reduction in dependency on oil, environmental impacts, resiliency Lanai involvement in designing metrics	Interested in the potential for a hybrid model Control of any model must be loca
Maui	Resilient grid Independence from oil Increased renewables Simplified interconnection process Grid modernization	Stakeholders understand how this model works Reliable electricity PUC's independence is beneficial Improved community engagement process Does not address cost shift and equity concerns Biased toward supply-side solutions	Some PBR components already incorporated Concern about unintended consequences Better align utility profits based on performance Will not address all issues [e.g., equity, electric vehicles ("EVs"), technology innovation] PUC would need more resources Metrics may be politicized	ISO implementatio in Hawaii would have to be very different than on mainland but could increase equality or the grid Disagreement if HERA would be a good solution

Location	Top Priorities	Discussion Highlights by Regulatory Model		
		Status Quo	PBR	Other Models
Molokai	Minimizing electricity costs Community engagement in utility decisions Increased distributed generation Competitive and public bidding process Efficient operations	Does not align with community priorities or include community involvement in decisions Procurement process does not require community input Does not address the long-term sustainability of projects nor prioritize diversity in renewable generation	Could give the community more input in decisions Metrics could include rate reduction, improving grid infrastructure, maximizing community benefits Want Molokai residents involved in establishing metrics	Would like a model that encourages economic development on Molokai, is inclusiv of small communities, incorporates community input, and includes assessments of environmental and cultural concerns Support diversity o renewables Market is too small for an ISO

Figure 14. Summary Table of Workshop Discussions: VERGE

Location	Top Priorities	Discussion Highlights by Regulatory Model: Status Quo	PBR	Other Models
Honolulu	Reliability and resiliency Reducing rates and equitable rates Achieving state policy goals Innovation Transparent and quick regulation process	Quality and reliable electricity Community engagement in the regulatory process is high Does not align utility incentives with policy goals Process needs to be quicker, more efficient, and more flexible	Could incentivize utility to meet policy goals Supportive of use of incentives and penalties Remove utilities incentive for capital investments Could reduce costs and give utility flexibility to meet goals Difficult to design and implement well and high potential for unintended consequences Metrics could include reliability, customer satisfaction, reduced rates, safety, environmental impact, social obligations, innovation, and employment beyond utility	HERA may increase independence with regards to grid reliability but would increase costs and is not a good fit An ISO would increase costs and would not work because the market is too small DSPP could expand deployment of DERs and allow for more innovation and competition but would require high up-front costs and would not work well Supportive of reduced regulation for co-ops

5.1.1 The City and County of Honolulu

Two meetings were held in the City and County of Honolulu, one in Kailua and one in Honolulu.[11]

5.1.1.1 **Honolulu**

The workshop was held at the Homer A. Maxey International Trade Resource Center Conference Room at the Hawaii Foreign-Trade Zone #9 in Honolulu. There were 17 participants.

5.1.1.1.1 Priorities for Stakeholders

The stakeholders discussed a multitude of priorities, with a particular focus on resiliency and reliability, listing the following as the most important issues:

- state renewable energy goals;
- local economic impacts;
- resilience;
- diversification to enable resilience;
- defense and resilience from hurricanes;
- power quality and reliability;
- storage to facilitate reliability;
- prevention of blackouts;
- enabling prosumers for reliability;
- grid access;
- consumer education;
- affordability;
- access to renewables;
- efficiency;
- innovation;
- microgrids;
- new technologies;
- fast adoption and easy on-ramps of new technologies; and
- less volatility.

5.1.1.1.2 Status Quo

The stakeholders explained that the status quo has resulted in high rates of solar adoption. They also discussed that service is safe and reliable, and that there is low volatility in electricity rates. A primary area for improvement was electricity costs. Stakeholders would like to see the current model improved by increasing grid access for IPPs, improving power quality, and increasing

---

[11] The VERGE Workshop was also held in Honolulu, but the summary is provided separately since there were participants at VERGE from across the state.

resilience to be better prepared for potential disasters. It was also explained that the current generation fleet is old and is in need of newer systems, particularly the faster adoption of renewable generation. There was the perception that HECO is "clinging to old assets" instead of investing in the grid. Additionally, stakeholders explained that the utility's website is not user-friendly and could be improved. Some stakeholders called the current model an "arcane regulatory model" that has not adapted to technologies and markets have changed and that it is not very resilient.

5.1.1.1.3 Small Group Discussion

Stakeholders felt that PBR seems very complicated but were supportive of it as a model that could provide flexibility and incentivize the utility to take actions in line with customer and policy priorities. Stakeholders liked the emphasis that PBR could put on continuous improvement over time and the potential ability community input to be included in the metric design. There were questions about how impactful PBR might be if only minor changes are implemented and interest in the adoption of more intense PBR components. Otherwise, some stakeholders were worried that it would not be much different from the status quo. There was concern that PBR could result in increased complexity and bureaucracy. For example, stakeholders questioned how the credit from solar generation would be delivered to the right person or entity. The stakeholders explained that designing PBR would require substantial expertise and that it would be difficult to avoid unintended consequences. It was mentioned that the PBR design should take into account what areas the utility can control versus what areas they cannot.

Stakeholders like the idea of being able to develop metrics in collaboration with the utility under PBR. They expressed interest in utility and transportation collaborations, GHG emissions, cost, and customer service as potential metrics. Stakeholders asked if PBR could be tied into the rate structure adjustments (e.g., rates that encourage efficient consumption, rates that achieve equity targets and benefit LMI customers).

Stakeholders were supportive of HERA as a model that would provide accountability, increased grid access, reliability, resiliency, and transparency. They questioned why HERA had not yet been adopted and also were not sure how HERA's role would differ from that of the PUC, stating that it could be redundant. There was support for the activities that HERA would theoretically undertake, but stakeholders wondered who was doing these now and, assuming that they are already being handled, wanted to know what the added costs would be to implement HERA, including potentially high upfront costs. There was concern that doing so would create another layer of bureaucracy. Overall, stakeholders were uncertain if HERA would solve the problems they identified in the status quo model.

There was support for an ISO as a model that would create more competition. However, stakeholders questioned if Hawaii's market was large enough for an ISO to operate. Stakeholders hypothesized that it could make more sense if there was a drastic expansion in the number of energy providers in the state.

Stakeholders were uncertain as to how the DSPP model would differ from the status quo. They wanted to understand how contracts would change under this model and how it would affect service and reliability because the stability of power quality was a priority. There was concern that the DSPP model is more radical and that it would then inherently contain more risk.

In regard to lighter regulation for co-ops, stakeholders were supportive of this option, stating that KIUC should be rewarded for its successes and that Hawaii should consider regulation levels for co-ops that are similar to those around the country.

5.1.1.1.4 Other Topics

In general, there was a lot of discussion among the stakeholders about incremental versus radical change to the regulatory model. Some suggested that Hawaii should take bold and innovative steps as they explained that there is too much to lose if only timid actions are taken.

5.1.1.2 **Kailua**

The workshop was held at the Enchanted Lake Elementary School in Kailua. There were 7 participants.

5.1.1.2.1 Priorities for Stakeholders

The stakeholder's primary priorities were focused on increasing the deployment of and access to affordable renewables while increasing plant efficiency and ensuring an open and competitive market for generation. There was some interest in supporting the deployment of wave energy technology. There was also discussion about the need for continuous improvement by the utility and throughout the system. One stakeholder mentioned that HECO's parent company should divest its ownership of American Savings Bank to focus on the utilities.

5.1.1.2.2 Status Quo

The stakeholders explained that the current model ensures utilities provide reliable service. There was a lot of support for the PUC's focus on improving energy efficiency through founding Hawaii Energy, with some stakeholders highlighting the benefit of having Hawaii Energy as a separate entity from the utility. It was also discussed that the current model had encouraged the development of renewable energy. However, some stakeholders disagreed, saying that they would like to see increased support for the solar industry, renewable deployment for homeowners, and storage and microgrid projects. Stakeholders discussed how the current model sends the "wrong incentives" to the utility because it creates a financial incentive to invest in capital improvements and provides no incentives for securing generation from less expensive IPPs. Additionally, some stakeholders explained that they would like to see an increased focus on undergrounding lines. Stakeholders also mentioned that HECO is beholden to shareholders and that this is one reason why HECO continues to be reliant on fossil fuels.

5.1.1.2.3 Small Group Discussion

The stakeholders were mixed in their support of PBR. There was concern that, under PBR, the utility could face the risk of losing all profits and even take losses, which would result in layoffs. However, other stakeholders explained that the "possibility to fail" would be a good incentive to HECO and would ensure that HECO shared some of the risks. In general, there was support for

PBR as an option to increase efficiency in operations within HECO. The stakeholders briefly discussed potential metrics, including customer satisfaction, outage statistics, and distribution capacity improvements.

Stakeholders were supportive of the ISO model because it could increase competition but were concerned that it would also increase risk, variability, and price volatility.

There was some interest in the DSPP model. Stakeholders explained that HECO "belongs in the wires business" and that they should continue to be compensated for that work. They liked that the DSPP model could create a competitive generation market that would provide more opportunities for renewables to enter the market.

The stakeholders were supportive of reducing regulation for KIUC, explaining that KIUC has demonstrated its ability to manage and operate the utility well.

5.1.1.2.4 Other Topics

In general, stakeholders explained that they would need to see cost estimates for each model to provide a useful opinion on each of these models.

5.1.2 Hawaii County

Two meetings were held in Hawaii County, one in Kona and one in Hilo.

5.1.2.1 **Hilo**

The workshop was held at the Waiakea High School in Hilo. There were 5 participants.

5.1.2.1.1 Priorities for Stakeholders

Stakeholders identified many priorities for utility regulation, but the highest priority was reducing rates. Other priorities included increasing renewable energy deployment, improving utility and grid flexibility and resiliency, and ensuring that solutions are adapted to the needs of specific locations based on local needs. It was discussed that market competition, not politics, should be driving investment decisions. While there was a strong focus on increasing DERs, stakeholders noted that utility-scale renewables are less expensive than DER solutions and that DERs will not be the best and only solution for meeting the state's electric needs. Instead, stakeholders would like to see an appropriate balance between grid-scale renewables and DERs. Stakeholders also mentioned that the equity of electric costs must be considered as the LMI community will have to carry more of the costs to operate and maintain the grid as wealthier residents defect from the grid.

5.1.2.1.2 Status Quo

The stakeholders highlighted that the current model has resulted in reliable electricity. However, there was concern that the current policy environment is driven by politics rather than allowing for the market to identify the best solutions. Additionally, it was noted that the current way in which electric rates are set is too complicated for most people to understand.

There was an in-depth discussion about the concern that the current regulatory model does not include representation from each county in PUC decisions. The stakeholders suggested that any regulatory model should include a mechanism for increasing local representation in regulatory decisions. One option that was discussed included establishing a PUC body for each island to address island-specific topics and decisions.

5.1.2.1.3 Small Group Discussion

Stakeholders noted that different models might be more appropriate for different islands and that proposed solutions should address the contexts unique to each island. It was recommended that the analysis assesses how different regulatory models would work on each island, with particular consideration of how the demographics and income distribution may result in differences in the impacts of each model on specific islands. Stakeholders explained that the cost of electricity is a significant portion of monthly income for many households on the Big Island. Additionally, it was pointed out that policies like net energy metering shift the benefits to wealthier households and increase costs for LMI households by increasing grid operation costs borne by households that are unable to afford rooftop photovoltaics ("PV"), placing an unfair burden on community members that can least afford it.

Stakeholders liked the idea of PBR and using unique metrics for each island to ensure that community-specific goals were incorporated into the regulatory requirements for utilities operating on each island. It was noted that "carrots work better than sticks" and, therefore, the softer PBR options focused more on incentives were preferable to more stringent PBR implementation. It was suggested that the project team review literature on performance-based contracts in general (not specific to the energy sector) to identify which mechanisms (e.g., carrots, sticks, others?) are most effective at driving desired outcomes. Stakeholders stated that PBR would fail if grid defection rates continue to increase.

Potential metrics that the stakeholders discussed included:

- Equity
  Stakeholders explained that the Big Island has a high number of residents that are low- and moderate-income households. As such, equity of costs was a big concern, and stakeholders like that PBR metrics could be designed to encourage utilities to better address equity issues. It was discussed that metrics could ensure that the impacts of decisions are not borne primarily by LMI households and require that any decisions identify which segments of the community benefit and which bear the costs. Potential components of an equity metric identified during the discussion included setting levels for the percentage of household monthly electricity costs for each level of income (e.g., no household pays more than X% of income for energy; people at 80% of poverty level don't pay more than X% of income for electricity).

- Load stability
  Stakeholders explained that load attrition is a problem for the Big Island and that it could be beneficial for a metric to be established for how well the utility does at stabilizing and/or retaining load. There is a social benefit to load retention because costs of the grid are spread across more people.

- Cost stabilization
  For cost stabilization, the stakeholders suggested that metrics be designed around the percentage of monthly income that households pay for their electricity.

There was concern that the DSPP and ISO models would not work in Hawaii. For the ISO model to function in the state, stakeholders explained that it would require a separate ISO on each island and that the costs to do this would be very high.

Regardless of the regulatory model, stakeholders expressed that it must be designed to be flexible to address changing technologies quickly and that, as a result, adaptability must be a priority.

5.1.2.1.4 Other Topics

One stakeholder noted that the presentation and report should include PV vendors as stakeholders having a strong influence on policy adoption and regulatory proceedings. It was also suggested that the analysis includes scenarios with the high deployment of rooftop PV and microgrids and the impact that this would have on the grid.

Stakeholders explained that Hawaii County is unique and that any changes will have a major impact on the grid. Stakeholders explained that it is important to understand how the increased adoption of EVs will impact the grid under each model as EV adoption was identified as a "tipping point" for the grid that will be reached most quickly on the Big Island.

One stakeholder mentioned that, although co-ops are costlier to operate and are less efficient to operate than IOUs, KIUC has been able to secure more favorable power purchase agreements ("PPAs") than HELCO and that HELCO should remedy this.

5.1.2.2 **Kona**

The workshop was held at the Natural Energy Laboratory of Hawaii Authority in Kona. There were 5 participants, though primarily only 1 person actively contributed to the discussions.

5.1.2.2.1 Priorities for Stakeholders

The priorities for utility regulation in Kona focused on improving electricity resiliency and security, mainly from severe storms, and increasing renewable energy generation. The stakeholders discussed the need for utilities to be flexible as new technologies that prove beneficial to Hawaii County come to market. Additionally, the stakeholders stated that utilities should be responsive to customer needs and should view customers as potential partners in meeting energy demands.

5.1.2.2.2 Status Quo

The stakeholders stated that HELCO balances supply and demand well. However, it was expressed that the current ownership model is "broken" and does not meet the needs of the community. There was concern that the current regulatory model does not allow for the flexibility in policy required for utilities to adopt new technologies nor to respond quickly to changes. An example provided was that the current policy for customers under net metering does not allow them to increase the size of their PV system while remaining under the net energy metering program. A stakeholder expressed that it would be beneficial for customers who have added an EV to be able to increase their PV system to offset the additional demand from their EV. Stakeholders mentioned that it would be beneficial to the community as a whole if regulations and policies increased incentives for customers to deploy renewable DERs that supplied energy to the grid. Additionally, stakeholders felt that the PUC is too cautious and weighs its decisions more toward the needs of the utility than of those that would increase clean energy deployment.

The stakeholders explained that any regulatory model must be customer-centric by prioritizing providing the best value to customers. Under the current model, HELCO is "slow and cumbersome," and does not operate in a manner that best meets the needs of customers. A model that would improve the utility's responsiveness to customers would be beneficial, and stakeholders suggested that HELCO look to KIUC's interactions with and responsiveness to their customers as a model to follow.

5.1.2.2.3 Small Group Discussion

Stakeholders expressed that regulation has one purpose – to protect the public interest. Any model that is adopted should do this and should not add costs to businesses nor stifle innovation. It was recognized that utilities need to make a profit but that they must also stay relevant to changing technologies. Stakeholders highlighted that any regulatory model that is used must address grid resiliency. There was concern that climate change will increase the number and severity of storms which will increase the operational risks to the grid. Increases in DERs, including microgrids and batteries, was proposed as a solution to improve resiliency

Stakeholders were supportive of PBR and increasing the link between utility revenues and performance but questioned why the current regulatory model does not already do this. For example, stakeholders explained that since the utility is currently required to meet the RPS requirements a PBR metric tied to renewable generation would be redundant. However, the stakeholders were supportive of the use of metrics that could be linked to goals with specific timelines as a way to drive utility action. Potential metrics discussed included progress toward RPS and increasing diversity of renewable generation. The stakeholders noted that with Puna Geothermal Ventures damaged by the volcano, HELCO would have difficulties meeting its RPS goals even over a longer horizon.

There was particular interest in two regulatory models: HERA and DSPP. Stakeholders expressed that HERA may be a good option as it could better drive HELCO to meet its RPS goals and liked that it could increase opportunities for access to the grid from non-utility players. However, there was concern that HERA may create redundancies and be inefficient.

Stakeholders described the grid as primarily a "giant battery," hypothesizing that the DSPP model may be the only relevant model in five years as the adoption of DERs is expected to increase rapidly as technology costs decrease. Unless the utility addresses this and identifies a path forward that meets customers' needs, stakeholders expected that grid defection would increase substantially as customers deploy combinations of DERs with batteries and microgrids. Blockchain technology was identified as a technology that will further enable contracts between customers without the need for engaging with HELCO to provide generation. Grid defection was considered the worst-case scenario as it increases costs for remaining customers which are likely to be those least able to afford it.

Stakeholders pointed out that the more complex a regulatory model is, the more difficult it will be to manage well. Any regulatory model should be well thought out before implementation because the whole community will "pay for it" if a regulatory model is implemented incorrectly or in such a way as to result in unintended negative consequences.

5.1.2.2.4 Other Topics

There was concern expressed with how the current RPS allows non-renewable generation, like burning trees for fuel, to count toward the renewable portfolio standard ("RPS") obligations. It was suggested that this component of the RPS be reformed.

5.1.3 Kauai County

The workshop was held at Kauai High School in Lihue. There were 11 participants. The discussion at the Kauai workshop focused primarily on the impact of regulatory models specifically on KIUC. There was no discussion of stakeholder priorities.

5.1.3.1 **Status Quo**

Stakeholders pointed out that the current model has resulted in reliable electricity delivery. As stakeholders across the state, there was agreement that the PUC is overburdened and does not have sufficient resources to handle all of its activities.

5.1.3.2 **Small Group Discussion**

The discussion focused primarily on how lighter regulation would benefit Kauai, with little discussion of the other models with a few exceptions. The stakeholders were adamant that HERA would not work in Hawaii. They stated that it would be costlier to implement, would only increase bureaucracy, and would provide minimal benefit to the state. The stakeholders also did not think that the ISO model would be appropriate for Hawaii. There was concern that costs would be too high to implement a DSPP model. Overall, some stakeholders thought that market approaches do not address reliability issues efficiently and, therefore, do not provide good solutions.

The stakeholders pointed out that most co-ops on the mainland are not regulated or not regulated as heavily as IOUs. They provided the example of Michigan, stating that the PUC is involved only in territorial disputes and other minor issues as needed. Additionally, they noted that many co-ops on the mainland are not under RUS control. They would like to take what is working well on the mainland for co-op regulation and apply it to Hawaii.

Stakeholders did not think that the PUC is more responsive to community concerns than KIUC and questioned how non-elected PUC commissions would be more sensitive to community needs than elected co-op board members. They stated that the PUC only visits Kauai 4-5 times per year while KIUC leadership lives in the community, interacts with ratepayers daily, and receives feedback directly from the community members. Furthermore, they stated that the board is responsive to community concerns, more so than the PUC has been. Board meetings are open to the public and community members regularly participate. Stakeholders stated that this sets them apart from the HECO Companies and is a main reason that PUC regulation is not as necessary.

Stakeholders explained that the current PUC regulation of rate cases was extremely costly for KIUC, saying that each costs millions of dollars. Additionally, they discussed how slow and burdensome the process is. As an example, they said that it took 6-9 months for the regulatory process in a recent solar case. They explained that these delays are expensive in a market that moves quickly. Another example that was provided is the community based renewable energy regulations under which KIUC is required to pay avoided cost of oil to solar projects even through that avoided cost is no longer relevant for KIUC.

The stakeholders felt that they are harmed by issues that are only relevant to the HECO Companies. They stated that the PUC is preoccupied with activities of the HECO Companies and cannot pay the necessary attention to KIUC which results in delays in rulings related to KIUC's issues. They provided an example of a case related to a cost of service study required by RUS that the PUC never approved and said that the process was a waste of resources for KIUC.

Stakeholders discussed the potential need for the PUC to provide dispute resolution services under a model with less regulation. Some stakeholders pointed to other co-ops where disputes are resolved through board elections and explained that, currently, only 250 signatures are needed to force a membership vote for issues that the board has decided on. This has happened twice in the history of KIUC and both times the membership voted to support the board's decision. Stakeholders explained that this threshold is very low and that they would like to see the number of signatures increased because it is expensive to hold a vote. Stakeholders pondered if there could be a role for a petition that could be a middle ground between a casual conversation with the board and doing a full membership vote.

Stakeholders felt that KIUC is more transparent than other co-ops and did not see a need for the PUC to be involved in mandating transparency. That said, they also explained that they were not concerned with the PUC's requirements about what information is made public as they would make this information public regardless.

The stakeholders did not agree with the idea that lighter regulation would result in a loss of revenue for the PUC, stating that it would reduce costs by reducing work for the PUC.

Overall, the stakeholders were very supportive of lighter regulation and were also open to an evolution of regulation over time. One stakeholder expressed that a model may work where the PUC was involved in fundamental issues, such as interpretation of a law, but where economic regulation was left up to the co-op's board. Others stated that they might be supportive of some type of "show-cause regulation" where the PUC would intervene if rate increases, or investments, surpassed a certain threshold or on specific issues as requested by stakeholders. The stakeholders agreed that they would like the PUC not to be involved in ratemaking for KIUC.

5.1.3.3 **Other Topics**

The stakeholders pointed out the importance of understanding the cultural differences between Kauai and the rest of Hawaii. Due to their relatively small size, they felt that their issues are ignored at the state level. However, they suggested that Kauai should be viewed as an example of what is working well.

5.1.4 Maui County

The Project Team held three meetings in Maui County, one each on Maui, Molokai, and Lanai. The summaries below are separated by meeting.

5.1.4.1 **Lanai**

The workshop was held at the Lanai Community Center in Lanai City. There were 6 participants.

5.1.4.1.1 Priorities for Stakeholders

The stakeholders expressed a strong preference for a model that would ensure the utility is responsive to community needs and that the utility incorporates community input into decisions. In combination with this, the stakeholders placed a high value on ensuring that there is a personal relationship between the utility and community members on the island, including those that provide energy through the use of DERs.

Another priority discussed was keeping fuel costs and, as a result, rates from increasing. The stakeholders mentioned that incentives to expand deployment of DERs by individuals and entities that own rentals (primarily Pulama Lanai's properties rented to employees) would benefit the island as a whole and individual household by reducing monthly electricity costs. They explained that increased adoption of DERs would act as a hedge against future increases in fuel costs.

5.1.4.1.2 Status Quo

The stakeholders explained that the status quo works well, that service is reliable, and that MECO maintains a personal relationship with the community. However, stakeholders expressed that the current model does not address all of the community's priorities. For example, the stakeholders would like to see a greater focus on keeping rates low for customers. Additionally, they would like to see an increase in incentives for rooftop PV and renewable energy in general and perhaps requirements for Pulama Lanai to install PV on employee rental properties. The stakeholders questioned why the fuel delivery costs are so much higher for Lanai than for the other neighbor islands and would like to see more equality in these costs.

In general, stakeholders were supportive of the PUC as an entity that ensures utilities operate in the best interests of Hawaii's citizens, and they see this as an integral role. They noted that the consumer advocate does not accurately represent the interests of the community on Lanai as it represents the state's interests broadly. The stakeholders explained that this has resulted in issues relevant to Lanai being dismissed.

5.1.4.1.3 Small Group Discussion

In general, the stakeholders were supportive of implementation of the PBR model as they felt that the use of metrics would be a beneficial way to ensure that community needs are incorporated into utility decisions. There was more interest in incorporating PBR metrics into the status quo as a method to modify the current regulatory model rather than implementing a major overhaul of the current model. In discussing potential PBR metrics, the stakeholders mentioned:

- generation efficiency;
- transmission efficiency;
- costs;
- reliability;
- upgrades to the transmission and distribution system, particularly in coordination with long-term planning;
- time to restore power after an outage;
- increased resilient supply of oil and reduction in dependency on oil;
- environmental impacts/benefits including increased deployment of renewables and mitigation strategies related to the potential effects of oil delivery and storage (e.g., oils spills and leaks, both in land and in the harbor); and
- resiliency planning, including strategies to mitigate system impacts if the infrastructure in the harbor in Lanai or Oahu is damaged and the barge is unable to deliver oil to Lanai for an extended period.

The stakeholders stated that the development of metrics must be conducted by entities within Hawaii and that it would be best if representatives from Lanai were involved in the process. They do not want the metrics developed by an entity outside of the state.

There was concern that the HERA, ISO, and DSPP models would not work on Lanai and would not work well for MECO. Specifically, it was noted that the market is too small on Lanai for these models to work well. Along those lines, stakeholders were united in stating the importance that any model must ensure that the current MECO staff on Lanai remain employed.

Regardless of the regulatory model in place, the stakeholders stated that any potential projects must consider and minimize environmental impacts and that the siting process must include a detailed environmental review.

Stakeholders pondered if it would be possible and beneficial to mix components of different models into a hybrid model that would best address Lanai's unique contexts. Additionally, they pointed out that they would like the analysis to consider how each model might result in increased employment opportunities on Lanai.

Stakeholders strongly expressed that the control of the regulatory model must be based in Hawaii and should not be managed by an entity outside of the state. Additionally, it was discussed that it would be preferable for there to be representation from the Lanai community on the regulatory body. Stakeholders discussed options for achieving sufficient representation, including having a resident of Lanai as an active member on the PUC. There was concern that an outside entity would be hired to implement and operate HERA or an ISO resulting in a loss of local control in regulations.

5.1.4.1.4 Other Topics

It was noted that Lanai is too small for a co-op ownership model to work well and cost-effectively.

The topic of Community-Based Renewable Energy was discussed, and stakeholders expressed an interest in the state working to make sure that this is implemented successfully. In relation to this, one stakeholder mentioned that Pulama Lanai is required through the community planning documents to develop a light industrial facility or area on Lanai but that it has not moved forward with this. The stakeholders identified this as a potential opportunity for Pulama Lanai to build a project under the Community Based Renewable Energy program.

The stakeholders encouraged the project team to consider that Lanai is unique and that this will mean that each model will have a different impact on Lanai than on the other islands. The stakeholders pointed out that one unique thing about Lanai is that the majority of the island is owned by a single entity. It was highly recommended that the project team engage Pulama Lanai to understand how any model would impact Pulama Lanai's operations on the island. As the primary land owner and primary energy user, stakeholders stated that any model must work for Pulama Lanai. Otherwise, Pulama Lanai may consider grid defection which would have a hugely negative impact on Lanai's grid and electricity costs.

5.1.4.2 **Maui**

The workshop was held at the Waikapu Community Center in Wailuku. There were 12 participants.

5.1.4.2.1 Priorities for Stakeholders

Overall, stakeholders prioritized a valuable and resilient grid that would allow Maui to achieve independence from oil. The stakeholders stated that they would like to see an increase in renewable generation but would like to do so at the lowest cost. To enable this to happen, they would like the interconnection process to be simplified and for the utility to be responsible for providing the necessary upgrades to allow for an increased renewable generation instead of new generators being required to do this. Grid modernization was listed as a priority, but stakeholders want to make sure that it is implemented correctly. In line with grid modernization, they would like for the deployment of storage to be optimized.

5.1.4.2.2 Status Quo

Stakeholders explained that one benefit of the current model is that everyone understands how the model works and the associated processes. The stakeholders agreed that the current model has resulted in reliable electricity and that the utility fixes outages and other issues quickly. Additionally, under the current model, the utilities have been forced to learn how to modify their operations to incorporate the adoption of a substantial amount of rooftop solar with minimal utility investment. The stakeholders highlighted that the PUC's independence is integral to its success and that this has worked well under the current model. The current model is seen as motivating regulators to act in a way that best serves the public good.

Stakeholders would like there to be an improved community engagement process. Currently, they see a need for the HECO Companies to be required to increase the involvement of stakeholders in the working group and other discussions and that stakeholder input influences utility decisions. They would like the HECO Company's working groups to influence change. Under the current model, the stakeholders view the working groups as more of a formality and the stakeholders do not think that the utility is listening to the community input. Additionally, it was recommended that greater efforts be made to bring a broader representation of community interests into the process as engagement is primarily focused on those involved in the energy sector.

The stakeholders also discussed the concern with how the current model does not address the cost shift and inequity problems associated with grid defection. For example, the grid was built to supply electricity to everyone but, with grid defection, the costs to maintain the grid are being borne more heavily by LMI households that are unable to afford their own PV system. This inequity will continue to increase as grid defection increases and must be addressed. It was noted that affordable housing is a primary concern for Maui and stakeholders would like to understand how this issue is being included in the analysis of regulatory models. Stakeholders explained that this cost shift is a serious issue and that, under the current model, it is not being addressed.

The current regulatory process is seen by stakeholders as biased toward supply-side solutions. They would like for the regulatory model to incorporate better and value the benefit of demand-side solutions.

5.1.4.2.3 Small Group Discussion

When discussing potential models, it was pointed out that the adoption of new models would not necessarily replace the current model. Stakeholders noted that any changes to the regulatory model and subsequent requirements placed on utilities must be equitable and must function for everyone.

Due to the recent legislative and PUC actions, the stakeholders viewed PBR as a "foregone conclusion" but recognized that there are many variants related to PBR implementation and the potential existed for it to be adopted with components of other models being considered in this analysis. Stakeholders noted that the current model incorporates elements of PBR already, including the regulatory lag. There was concern that there will be unintended consequences related to the adoption of PBR, mainly based on how the metrics are defined. PBR was viewed as a solution to one problem (better aligning utility profits based on performance), but there was concern that PBR is being discussed as the solution to all of the state's energy problems. For example, stakeholders explained that is unclear how PBR will address equity issues or integration of EVs and other technology innovations that will require a grid that operates differently than it has in the past.

Stakeholders noted that the implementation of PBR would likely require revisions within the PUC itself. For example, there would need to be additional staff with the necessary experience to implement PBR. Additionally, the PUC's software systems would need to be updated, notably to allow for the required increased data sharing under the legislative requirements. Stakeholders questioned whether or not the PUC has the capacity to do this.

There was concern that any metric considered for inclusion under PBR would be politicized and that it will be difficult for an agreement to be reached regarding metrics and implementation in general. Stakeholders discussed that performance metrics should incentivize the utility to move toward relying more on technological or platform solutions to operate their grid rather than on capital-intensive approaches. One stakeholder mentioned the Federal Communication Commission's spectrum auction as a potential example to follow when creating an auction for DER under PBR.

Stakeholders mentioned that there are many similarities between an ISO and HERA. Stakeholders disagreed about whether or not HERA would solve any problems. While some did not think that it would do so as the utility is currently responsible for maintaining the grid, others explained that HERA would set a standard for the utility to follow and result in more cost-effective infrastructure investments. For example, a stakeholder explained that utilities would be unable to adjust reserve margins in order to justify more capital investments. There was concern that IPPs would have increased responsibilities for maintaining the grid under HERA. The impartiality of HERA was seen to be beneficial as stakeholders explained that it is currently difficult to determine the cost to connect to the grid which has resulted in distrust of how the utility is assessing the costs.

When discussing an ISO model, stakeholders explained that any implementation of an ISO in Hawaii would be very different than implementation on the mainland. Stakeholders asked if anything would be much different under an ISO since there would still be a single vertically integrated utility. It was questioned if an ISO provides a solution on Maui where there are thousands of small generators, not thousands of utility-scale generators like on the mainland. It was also noted that ISOs typically operate at the transmission level when one would need to operate at the distribution level in Maui due to the amount of DERs. Stakeholders discussed that an ISO would just manage grid access and dispatch, some of which HERA could address. Stakeholders were supportive of the increased equality in dispatch control that an ISO would bring to the system.

Regardless of model, the stakeholders would like to see increased impartiality when it comes to the integration of DERs into the system. Stakeholders recommended that the analysis consider how different regulatory models would work with varying models of ownership. They would like to understand if different regulatory models are more suitable with varying models of ownership and if different regulatory models would be more appropriate on each island.

It was brought up that some of these models may make more sense if the islands were interconnected, particularly by increasing the economies of scale. Stakeholders discussed that although interconnection is still in HSEO's plans, both the current governor and potential future governors are against it.

5.1.4.2.4 Other Topics

Stakeholders discussed the need for there to be coordination between the legislative, regulatory, and administrative processes in relation to this topic. It was perceived that the legislature passes bills without having done the necessary due diligence regarding analysis or coordination with other government entities. Stakeholders viewed this inconsistency in actions as unlikely to result in practical and successful implementation. Consistency from the legislature over multiple years was considered to be more helpful in supporting the PUC's implementation of policy.

There was interest in increasing the use of non-wires alternatives and better understanding how to create and leverage these opportunities throughout Maui.

One stakeholder recommended that the project team increase stakeholder outreach to discuss these options with stakeholders representing broader interests on Maui as it seemed that most stakeholders participating in the meeting were formally engaged in the energy sector. Similarly, there was concern that this lack of representation from the broader community would result in a backlash against any recommendations from the analysis.

It was brought up that people who defect from the grid are seen as acting nobly even though their actions have a negative impact on others who now must pay an increased share for maintaining the grid.

5.1.4.3 **Molokai**

The workshop was held at the Mitchell Pauole Community Center in Kaunakakai. There were 12 participants.

5.1.4.3.1 Priorities for Stakeholders

The primary priority for stakeholders was keeping electricity costs as low as possible. There was strong agreement among the stakeholders that the community should be involved in utility decisions and involved from the early stages of any potential project or planning process. The community would like to have more options and more control over the costs of electricity. Additionally, there was interest in increasing distributed generation as a way to both lower costs and increase community ownership in electricity generation.

Many stakeholders mentioned extreme concern with the utility's lack of a public bidding process for generation projects with specific mention of the Half Moon Ventures project. They would like to ensure that there is a robust public bidding process which enables competition and allows the community an opportunity to provide a proposal and to provide input on project selection.

The stakeholders identified both efficient operations and system-wide/island-wide efficiencies as a priority area for any regulatory model to consider. For example, it was discussed that there might be opportunities to coordinate operations of multiple systems (e.g., water, agriculture, economic development) across the island to maximize efficient use of resources more cost-effectively than considering each system individually.

5.1.4.3.2 Status Quo

In general, the stakeholders did not feel that the current regulatory model aligns well with community priorities. However, there was recognition that the appliance replacement program that MECO operates is well run and provides a benefit to the community.

The primary concern with the current regulatory model was focused on the procurement process and that it does not require the utility or PUC to include a stakeholder review from residents on Molokai for any potential projects, regardless of size.[12] The stakeholders would like to see a drastic improvement in the amount of engagement that local residents can have in the review of and decision making related to all projects. It was pointed out, however, that MECO has improved their engagement with the community. The stakeholders were appreciative of this effort and the opportunity for their input to be considered in the utility planning process. It was suggested that a possible solution would be for the PUC and utility to consult with either the County Council or Molokai Planning Commission on any potential projects.

Additionally, stakeholders would like to see a model that increases the use of and diversity of renewable energy projects, including pumped hydro as a method for storing renewable generation for dispatch as needed and use of landfill gas for electric generation. It was stated that all projects should consider the long-term sustainability and cost of projects and they would like to see the utility consider making system upgrades rather than building new generation as that might be a more cost-effective option over the long-term.

5.1.4.3.3 Small Group Discussion

The majority of the small group discussion focused on the characteristics of an ideal regulatory model rather than on each specific model being assessed for the study. There was strong interest in understanding which model(s) would result in the greatest economic development for Molokai. The stakeholders were supportive of unused or underutilized land being put to productive use in coordination with creating jobs for residents. One example discussed was the creation of a hibiscus farm that would provide long-term, sustainable jobs for the community. Stakeholders wondered if it would be possible to identify similar solutions for renewable generation projects.

Stakeholders asked which model would be most inclusive of small communities and suggested that any model include a formal process requiring any PUC regulated entity to implement a community engagement process. They would like to see a model that includes a formal process for community input. For example, the stakeholders suggested that there could be an advisory group established under any model which would include representatives from each island. There was concern that a single entity would be selected to represent Molokai's interests and that it would be preferable to have multiple representatives from Molokai no single entity could accurately represent the community's diverse interests. They felt that the Community Plan should be used as a guide for potential projects and that the County Council should be involved in all discussions about potential projects at an early stage and throughout the entire discussion. They expressed concern that there is the potential for corruption under any model and, without

[12] The current regulations stipulate that the utility does not need to conduct a competitive bidding process for procurement of generation if the net output available to the utility is 1% or less of a utility's total firm capacity (see page 4 of HPUC Docket 03-0372, Decision and Order No. 23121, available at http://files.hawaii.gov/dcca/dca/dno/dno2006/23121.pdf).

sufficient local representation, it would be difficult to trust that the community's best interests were being considered.

Regardless of the model, stakeholders explained that it is imperative for it to ensure that Molokai residents can provide input on RFPs and that they have the opportunity to submit proposals through a competitive bid process. They would like local economic benefits such as job creation to be included as a factor in project evaluation.

The stakeholders stated that any model must ensure that environmental and cultural concerns are incorporated in the assessment of potential projects. They would like all utility projects to be required to complete a "full environmental review" and a Programmatic Environmental Impact Statement.

The stakeholders would like to see the regulatory model encourage and support the creation of creative partnerships to develop solutions. They also highlighted that any model must include a mechanism for assessing any potential project or decision based on the impact that it will have on future generations.

There was interest in increasing the diversity of renewable energy generation across the island and supporting the development of smart grid technology. The stakeholders were interested in understanding how each model would address this.

In general, there was interest in PBR as a model that would allow the community to have more opportunity to drive utility decisions and ensure that they are in line with the community's goals. They would like to see metrics addressing reducing rates, improving grid infrastructure, and maximizing the community's benefit from any investment while balancing the benefits of grid maintenance with increased generation. The stakeholders questioned who would establish the goals under the PBR model and reiterated that Molokai residents must be involved in the process.

One stakeholder mentioned that an ISO would not work on Molokai as the market is too small for this model.

When Hawaii's community-based renewable energy program was brought up, stakeholders expressed interest in learning more about options and how a project under this program could increase the opportunity for more direct community participation in generation. Additionally, they would like to see a program that resulted in the installation of solar hot water systems on every resident's property.

5.1.4.3.4 Other Topics

The stakeholders explained that they do not like it when organizations (e.g., consultants, developers, and the utility) present them with a solution. Instead, they would like to be involved in the process of identifying and assessing potential solutions from the beginning. Additionally, one stakeholder expressed concern that the state hired an out of state consultant to conduct this study when it would be better to have an in-state company with connections to the community conduct the analysis. The stakeholders recommended that additional outreach be held before the community meetings to ensure more people are aware of the meetings, and suggested advertising in the local newspaper, speaking with the county council and Molokai Planning Commission, and perhaps even having meetings in each district on Molokai instead of only in Kaunakakai.

One stakeholder mentioned that microgrids would be a good solution for Molokai and that they would like to see microgrids developed on the island.

There was some interest in a co-op ownership model, but stakeholders noted that it would not work for Molokai if the community had to start out in debt.

The stakeholders strongly expressed concern and anger about the Half Moon Ventures project. In general, there was frustration that MECO was not required to conduct a competitive bidding process for the project, that the community was not consulted, and that it would not be the best use of Hawaii's GEMS financing program.

5.1.5 VERGE Workshop

The VERGE Workshop was held at the Hilton Hawaiian Village in Honolulu. There were more than 100 participants.[13]

5.1.5.1.1 Priorities for Stakeholders

The stakeholders identified the following priorities:

- reliability/stability;
- achievement of state policy goals such as the RPS, but potentially others;
- reducing rates;
- innovation and openness to the adoption of new technologies;
- equity between customer classes;
- transparency, including improving public awareness and understanding of the regulatory process;
- ensuring rate design has appropriate incentives;
- grid resiliency;
- improving the speed of the regulatory process;
- providing a framework for investment; and
- implementing a model that will function in an island context.

5.1.5.1.2 Status Quo

Under the current model, stakeholders expressed that the quality and reliability of electric service is good. It was felt that the PUC communicates well with the utilities about dockets and that

[13] Very few of the participants signed in at the VERGE workshop.

consumer engagement in energy issues is high as both the PUC and utilities have improved transparency and public outreach.

Stakeholders noted that the PUC is already incorporating some elements of PBR that incentivize the adoption of renewable energy (e.g., competitive bidding, decoupling, etc.). However, they expressed that the current model does not generally align the utilities incentives with policy goals.

The primary improvement needed as identified by stakeholders was the speed and efficiency of the regulatory process as it is considered to be too inflexible. In general, stakeholders would like to see the regulatory process revised to ensure that utilities are better meeting the priorities identified above in 5.1.5.1.1. Other improvements included using a "holistic approach" and being more results-focused. However, there was conflicting input on whether there should be more or less oversight by regulators.

5.1.5.1.3 Discussions on Models

5.1.5.1.3.1 HERA

Many stakeholders did not see HERA as a good fit for Hawaii and questioned its necessity. However, some mentioned that it would provide a layer of independence in regards to reliability and may improve or complement the regulatory process. In general, stakeholders saw HERA as adding unnecessary costs and complexity to the regulatory framework and stated that it would be redundant. There remained uncertainty about how HERA would work and what implementation costs would be.

5.1.5.1.3.2 ISO

The majority of stakeholders did not think that it would be beneficial to adopt an ISO model in Hawaii. However, they noted that it could be more efficient in terms of time and costs if markets could be established and would provide more opportunities for stakeholders outside of the utility. Someone also pointed out that an independent entity may have a better rating than the HECO Companies. In general, stakeholders explained that adoption of an ISO would increase costs and bureaucracy. Overall, it was thought that an ISO could not work in Hawaii because it is too small, and each island is a separate grid.

5.1.5.1.3.3 DSPP

Stakeholders discussed that this model could result in an increase in DER deployment and customer choice and were supportive of the potential for growth in innovation and competition under this model. However, they were concerned that the high up-front costs to establish this model and the market depth needed for it to operate well makes it a poor choice for Hawaii. Some stakeholders explained that this model could result in lost opportunities on transmission and generation optimization. There was general uncertainty about how this model would work, with stakeholders posing the following questions:

- Would all customers be served?

- Would we lose control over managing the grid?
- Would risk increase for investors?
- Would the system be fully reliable?

5.1.5.1.3.4 PBR

Overall, many stakeholders were supportive of the adoption of PBR as a way to augment the existing system. They saw the model as a way to encourage innovation and align utility actions with state policy goals. Many stakeholders liked the use of incentives and penalties as a way to help utilities to take specific actions and as a way to hold them accountable if they do not meet the goals. The stakeholders saw an earnings sharing mechanism ("ESM") as a way to align the utility's actions with policy and consumer goals.

Additionally, it was noted that some components of PBR are already in use in Hawaii and that there is a precedent for this type of model. The stakeholders were supportive of PBR as a way to remove the utility's incentive to increase capital investments and saw this as a path for reducing costs and giving the utility greater flexibility in meeting targets. Stakeholders liked the idea of capping utility prices or revenues as because of the rate certainty it would provide to customers and that it would encourage the utility to be more efficient. The model was seen as a way to increase utility flexibility and, if done correctly, reduce costs.

There was concern that there is not a single PBR model that works well for every location and that example models from other jurisdictions will not work in Hawaii's unique situation. Stakeholders pointed out that it is difficult to forecast correctly and would, therefore, be difficult for regulators to design PBR successfully. Many stakeholders mentioned the potential of perverse incentives and negative consequences if PBR is not designed carefully. There was concern that it will be difficult to design penalties fairly and such that they do not penalize the utility for areas outside of their control. Similarly, it was expressed that it would be challenging for a rate or revenue cap to be set at the appropriate level without leading to unintended consequences. Stakeholders wondered if an ESM would reduce the utility's incentive for investing in longer-term projects, and that this would result in higher costs for customers in the future. Some stakeholders explained that removing the utility's incentives for capital investments may make it more difficult for the utility to access capital and, therefore, be riskier than the status quo.

There was also a lot of uncertainty about how PBR will be designed and implemented, particularly regarding incentives.

Potential metrics discussed by stakeholders included:

- reliability and availability;
- customer satisfaction (could cover cost, accountability, and reliability, data and education);
- lower prices;
- safety;
- environmental impact;
- aligning with social obligations;
- innovation;

- aligning utility and customer incentives;
- consider impacts on employment in other sectors besides energy; and
- general discussion that it would be useful if PBR could result in broader positive implications across the economy.

In general, there were questions about how PBR would be implemented. For example, someone asked if it would make sense to do a pilot study, others discussed if it would be scaled up over time, and there was interest in more information and education being provided to the public surrounding PBR.

5.1.5.1.3.5 Lighter Regulation for Co-ops

Stakeholders were supportive of lighter regulation for co-ops because unregulated co-ops work well in other parts of the country. They saw reduced regulation as a way to streamline the co-op's processes, reduce costs, and give KIUC the ability to make decisions more quickly. There was a concern, however, that lighter regulation could lead to higher rates and an inability of the state to ensure co-ops to comply with state policy goals. Stakeholders explained that ratepayers would have no recourse aside from judicial action if the co-op is not taking appropriate measures in line with the ratepayers' interests. Some also brought up that this could result in differences in utility processes and policies on different islands which would make it more difficult and costlier for developers that work on multiple islands.

5.2 Bilateral Discussions

The teams conducted multiple bilateral meetings during the two weeks, as listed in Figure 15, meeting with 19 individuals representing counties, utilities, non-profits, state and local elected officials, and the private sector. The comments are compiled by themes in the list below. They are not attributed to a specific individual or organization.

Figure 15. Bilateral Meetings

	Team 1	
	Island	**Organization/Individual**
12-Jun	Oahu	Hawaii Solar Energy Association HECO Management Rep. Nicole Lowen
13-Jun	Oahu	City and County of Honolulu Lorraine Akiba, Former PUC Commissioner Randy Iwase, PUC Commissioner Rep. Chris Lee
14-Jun	Oahu	Carl Caliboso, Former PUC Commissioner Distributed Energy Resources Council Elemental Excelerator Ulupono Initiative
15-Jun	Kauai	County of Kauai Hermina Morita, Former PUC Commissioner
	Team 2	
	Island	**Organization/Individual**
21-Jun	Hawaii	County of Hawaii Hawaii Island Energy Cooperative

The comments from the bilateral meetings are summarized and combined by the topics below.

5.2.1 Priorities

Improving the interconnection process, reducing the time to interconnect, improving interconnection transparency, and reducing interconnection tariffs are priorities for the DER industry. Though it has improved slightly, they feel the process is still too long and impacts project economics. It is not only the utility process that is causing delays, but also the municipal permitting process. The informal interconnection process varies across the HECO Companies and is entirely different for KIUC which makes it difficult for companies that work on multiple islands, increasing the cost of interconnecting. It would be beneficial for the process to be consistent across all utilities. Additionally, the solar market on Kauai is only open to a small number of on-island companies.

Affordability and cost control, in general, were mentioned by many stakeholders with some stating that these are the number one priorities, even before meeting RPS goals.

Multiple stakeholders highlighted the importance of improving resiliency. Resilient electricity supply is critical however it is not efficient for a utility to have excessive redundancy in place (e.g., it was questioned if HELCO has had too much redundancy since the utility has explained that they will not have any supply disruptions with PGV being closed). It may be more cost-effective to have smaller, more diverse generation sources providing redundancy. Innovative ways should be explored to achieve reliability rather than building massive amounts of additional capacity.

Utility customers want the ability to develop their own generation projects that increase their resiliency and, for some, reduce their greenhouse gas ("GHG") emissions.

For customers that have public policy goals, they would like to see a regulatory structure that enables them to meet these goals.

5.2.2 Status Quo

Some stakeholders explained the current regulatory model is working well. They felt that the legislature has been proactive in establishing a clear policy and the PUC has taken this direction seriously. Additionally, the PUC has been open to stakeholder engagement in dockets. The current model is seen as providing benefits and efficiencies with a single body (the utility) operating the entire system. There was concern that models which separate some components of grid management will be less efficient.

Stakeholders expressed frustration with the lack of local control in the decision-making process. All of the decisions impacting the electricity system are seen as being made in Oahu, via the legislature, PUC, or the HECO Companies. Due to the balance of power, stakeholders explained that representatives from Honolulu have the majority and can dismiss the interests of the neighbor islands.

There was concern that the current model is not transparent in how and why utilities and the PUC are determining which renewable projects are approved. For example, the PUC has approved large solar with higher costs than compared to distributed solar projects. Stakeholders would like to see the process conducted in a competitive, transparent manner like what the PUC did with energy efficiency.

Multiple stakeholders stated that the PUC is understaffed and does not have sufficient resources to operate. Additionally, it was mentioned that the PUC plays many roles and has similar responsibilities to the North American Electric Reliability Corporation ("NERC"), an ISO or regional transmission organization ("RTO"), and a PUC at the same time. One stakeholder suggested that interconnection studies could be outsourced to improve the speed of interconnection. Another stakeholder highlighted the importance of having consultants as independent investigators, facilitators, and working groups to support the PUC.

Multiple stakeholders explained that the interconnection process is too slow and cumbersome due to the utilities' operations. However, some stakeholders mentioned that it has improved, and that technical concerns with interconnection have arisen first on Maui but will be delayed on Oahu as the grid is more robust.

There was concern that the necessary data is not currently tracked. For example, data on the process for interconnecting (i.e., the time from interconnection application submittal to connection to the grid), capacity provided by renewables, and DER data are not currently tracked sufficiently. It was recognized that this data would need to be tracked for implementation of many potential regulatory changes.

The HECO Companies are seen as difficult to work with, and there was interest in understanding how different models could move the utility to operate more of a service model. One stakeholder suggested that there needs to be a cultural shift where the utility proceeds to operating more like a technology company than a government-like organization.

Some stakeholders explained that there is no dedicated focus on driving innovation in the current model and that the utility should be required to have an innovation budget, not just an R&D budget.

5.2.3 HERA

Some stakeholders saw this model as redundant with the ISO model, and one stakeholder questioned if HERA would truly be able to remain independent. Stakeholders speculated that HERA had not been implemented for two reasons: first, because the legislation does not mandate its implementation and, second, because the PUC put other utility issues on hold while the NextEra acquisition docket was being considered.

One stakeholder highlighted the value that HERA would provide by ensuring a competitive framework for interconnection that does not favor the utility and, therefore, leveling the playing field for non-utility players. It was noted that the PUC does not currently have the technical ability nor resources to implement HERA but that it could potentially be operated as a small office with funding from the PUC. To be performed well, stakeholders noted it would require strong support from PUC commissioners.

5.2.4 ISO

One stakeholder commented that an ISO does not make sense for Hawaii.

5.2.5 DSPP

Some stakeholders expressed interest in the DSPP model. For example, stakeholders that work in the DER industry explained that this model might be preferable because it would increase deployment of DERs. Other stakeholders expressed that this model seems to create a lot of opportunities to incorporate electric vehicles, on-bill financing, and other options. There was some who valued that this model would allow for small customer-to-customer based transactions.

5.2.6 PBR

In general, stakeholders were supportive of PBR. Stakeholders viewed PBR as a way to better balance the risks between the utility and the ratepayers. There was support for reducing or eliminating utilities' motivation for increasing capital expenditures and breaking the link between capital investments and rates. Additionally, stakeholders viewed PBR as a way to align the shareholder values with policy and community goals. PBR was seen as a good option for this, especially in light of rapid changes in technology and the unique issues that pertain to a primarily rural state. It was suggested that PBR could be designed to increase the penetration of DERs. However, it was noted that it would be beneficial if it could also address issues associated with rate design and the inequities created in the cost shift associated with DERs.

There were many topics related to PBR discussed during the bilateral meetings, and they are summarized by category below.

5.2.6.1 **Design and Unintended Consequences**

It was recognized that PBR is a complicated topic and that the "devil is in the details" when it comes to design and implementation. While there will inevitably be some mistakes made in implementing PBR, stakeholders explained that the PUC could not afford to make enormous errors as it would be extremely costly to the ratepayers. As the timeline for implementation is relatively quick, some stakeholders felt that it is more critical for the PUC to implement PBR correctly than to meet that timeline. Additionally, stakeholders strongly expressed concern that there will be unintended consequences if PBR is not implemented through a well thought out process. To prevent this, it was recommended that PBR not be designed to be too rigid in the initial years and that it be implemented through incremental changes over time. It was noted that PBR implementation should recognize what the utility does and does not have control over. For example, the utilities do not have complete control over the permitting process and issues like local opposition impede project development.

5.2.6.2 **Breadth of Regulatory Change**

The interest in the amount of regulatory change varied across stakeholders, with some preferring moderate and incremental changes and others preferring more revolutionary change. Some saw PBR as a good first move toward implementing changes to the status quo. Others discussed the potential for gradual evolution or using "shadow rates" to incrementally perform PBR. A broad change in regulation was seen to be unlikely by the 2020 timeline, and it is expected that PBR adoption will look more like modifying the current regulatory model.

Stakeholders noted that the current model already incorporates some components of PBR, including the earnings sharing mechanism (e.g., the HECO companies are required to share benefits of the lower tax rate after recent tax reforms). Performance incentive metrics ("PIMs") are also included, and it is unclear to some stakeholders if expanding PIMs would be sufficient to accomplish the goals of the legislature or the PUC docket in regards to PBR.

5.2.6.3 **PUC Resources**

Many stakeholders were concerned that the PUC does not have the staff or financial resources to successfully develop and implement PBR.

5.2.6.4 **Financial Impact on Utility**

There was concern expressed about how the PBR legislation was written without regard for financial markets or the potential impact on the HECO Companies. Stakeholders mentioned that the legislation created substantial concern for investors, but that the docket provided a calming effect as it more thoughtfully considered the issues and implementation of PBR. It was pointed out that the HECO Companies have a BBB- rating and that implementing PBR, primarily if it is poorly designed, could result in credit rating companies downgrading the HECO Companies which could destroy the utility.

For PBR docket, it is important to understand how different designs that are being considered would impact utility finances. The utility's capacity for debt is essential, not just its annual income. Regardless of the regulatory model, the HECO Companies will have a fundamentally similar capital model which focuses on institutional investors. While a utility in a larger area could reposition itself as a growth opportunity expanding into new markets to attract different investors, the HECO Companies have no potential for growth and will always be a small utility. It is necessary to maintain a reasonable amount of dividend growth to ensure institutional investors remain interested. The dividend growth could be reduced, but it must stay attractive to the pension fund market.

5.2.6.5 **Implementation Elsewhere**

One stakeholder felt that there is a lack of experiential data on PBR implementation and, therefore, little understanding of what has worked well and what it costs to implement.

Stakeholders felt that New York's Reforming the Energy Vision would not work in its pure form in Hawaii. However an "impure" form could work. Stakeholders explained that it would be fine to rate base grid improvements, but that fuel costs would need to be reduced, or the LMI customers will bare increasing costs as wealthier customers defect from the grid.

5.2.6.6 **PBR Docket**

Stakeholders saw value in the PBR docket process and outcomes. Some stakeholders mentioned that it is too early in the docket process to understand if a light PBR or a more extensive implementation of PBR would work better. However, implementing PIMs is seen as a relatively easy way to better align the utility with the community goals in the near term. Some stakeholders pointed out that there is interest in more radical change, however, as incremental changes have not resulted in the necessary adjustments to move the utility.

5.2.6.7 **Metrics/Incentives:**

It was expressed by multiple stakeholders that IOUs respond well to incentives, but there was concern that this would just result in higher rates for ratepayers. One stakeholder recommended that the best approach for determining regulatory changes is first to determine what the utility's role should be in the system and then determining which assets should be owned by the utility, which could differ in front of and behind the meter and may also vary from what the utility operates. Following this assessment, the requirements for utility performance could then be determined and could include operational performance metrics that are quantifiable and transparent. This could include a political and negotiated discussion of how savings are shared.

Stakeholders explained that when selecting and designing metrics, regulators must understand that specific groups of PIMs work well together financially, and that PIMs cannot be cherry-picked. There are unintended consequences with each potential PIM, and the regulators should identify those with the fewest unintended consequences.

Some metrics were discussed by stakeholders including:

- rate stabilization or reduction;
- progress toward RPS, carbon-free energy;
- responsiveness to customers and interaction with the community;
- improved interconnection process, reduced time to connect, and transparency in the process;
- resiliency: primarily grid resiliency but also social and community resiliency;
- equitability of pay: for example, a potential metric could be the ratio of the utility CEO's salary to the salary of the average employee or the median household income for the utility's service territory, with the goal being for a lower ratio;
- energy resource planning;
- efficient, holistic service providers, including non-wires alternatives, similar to New York's Reforming the Energy Vision;
- the diversity of generation sources;
- valuing the unique goals for each island; and
- innovation: could include the number of new projects, number of scaled pilot projects, hiring a chief innovation officer at a high level in the utility, developing and implementing an innovation strategy.

5.2.7 Lighter Regulation for Co-ops

There was general support for reduced regulation for co-ops and many stakeholders viewed the current regulation as costly for KIUC. The stakeholders said that it would be difficult to estimate the costs of regulation but that in a rate case year it could be around $3 million. Stakeholders explained that the high costs to revise rates had prevented KIUC from implementing rate changes that it would like to make to better serve customers, such as an EV rate.

Stakeholders explained that lighter regulation would work because KIUC

- moves faster than HECO on many issues and is held up by regulation;
- knows their system well and is willing to experiment in ways that the HECO Companies are not;
- has strong leadership; and
- is flexible and adaptable.

Stakeholders mentioned that there may be a pathway for the PUC to follow to reduce regulation for co-ops but that it would most likely require legislative action for any change. If regulation were reduced, stakeholders expressed concern about how any inconsistencies with congressional direction would be enforced. The example of KIUC interpreting the Community-Based Renewable Energy docket differently than the legislature or PUC was discussed, with stakeholders questioning which body would be the one ultimately responsible for understanding these policies.

It was explained that KIUC primarily participates in dockets to ensure that they are not negatively impacted by resulting decisions. As such, stakeholders felt that reduced regulation for co-ops would lessen the PUC's burden.

Stakeholders hypothesized that there would not be as much opposition to reduced regulation as there was when KIUC formed. However, one stakeholder noted that there was opposition from the PUC in relation to the decoupling docket.

Stakeholders discussed the potential for a more "light-handed approach" where the co-op would not need to seek approval for specific actions as long as certain thresholds were not exceeded. Potential limits discussed included:

- A rate increase exceeding X%;
- Project costs exceeding $X; and
- Customer disputes are exceeding X% of the customer base.

If the thresholds are exceeded, PUC involvement would be triggered. However, it was noted that the thresholds would need to be designed to exclude factors beyond the control of the utility (e.g., pass-through fuel costs). Under this model, the PUC could still have the opportunity to weigh in on governance issues. Under this model, stakeholders suggested that project approval and rate approval could be deregulated with thresholds established (i.e., a dollar threshold above which projects would require approval).

Stakeholders felt that KIUC's board is strong and knowledgeable. There was some mention of increasing concern regarding the potential for board capture and if the board just complies with the desires of the CEO.

The stakeholders point to the community oversight as a result of the co-op structure as a benefit of KIUC and a reason that lighter regulation would work. It was explained that very few signatures are required to trigger a community-wide vote of a board decision but that it has still happened only twice. For both of these votes, the community supported the board's decisions. This is seen as a good check and balance for the board.

Stakeholders explained that they are not concerned about issues related to dispute resolution in a deregulated environment because the community has handled dispute resolution more informally since it is a small population. Additionally, stakeholders stated that it is not hard to change the board as 500 votes could swing the decision. If issues did arise, it was discussed that the CA's attorney general could act as a watchdog or advocate. There were only minimal concerns about the potential for the voting structure to create perverse incentives.

Other stakeholders explained that there is a need for continued regulation of co-ops in Hawaii, particularly in regards to rates, PPAs, and customer complaints.

5.2.8 Other Topics

5.2.8.1 Ownership Models

Stakeholders discussed various topics related to ownership models. In regards to co-ops, it was noted that KIUC was successfully established because there was a willing seller. Though KIUC is considered successful, some said that it is not merely successful because it is a co-op but because of the knowledgeable leadership, the utility's focus on keeping the community satisfied, the appetite for risk, and the community's small size which allows for decisions to be made quickly.

Moving to a co-op is not seen as a solution for all of the problems that people identify with the HECO Companies. It was discussed that a co-op model might be more challenging to operate on the other islands due to the population size and the need for transmission across more considerable distances. One stakeholder said that although there is a lot of discussion of or interest in co-ops, which it is imperative that a community would need to demonstrate that they are capable of purchasing and operating a utility before any change to a co-op be considered seriously. There seemed to be a consensus that a co-op model would not be successful on Oahu but could work on the Big Island and perhaps on Maui. Some stakeholders thought that a vertically integrated IOU has different drivers than wires only models that benefit the community.

Input differed on the interest in co-op ownership of a utility on the Big Island. One stakeholder explained that the general interest in developing a co-op declined after the PUC's ruling on the NextEra acquisition. Conversely, a different stakeholder said that community members are "emotionally drawn" to a model where they can directly influence the decisions. Even for those interested in the model, there are questions about how it would impact rates and how it would be operated. Multiple stakeholders mentioned that KIUC is viewed as a successful model because they have a higher penetration of on-grid solar and have pursued more innovative and experimental solutions (e.g., pumped hydro, solar plus storage). It was noted that KIUC seems to be able to act more quickly and that it has a more straightforward procurement process.

Stakeholders explained that the IOU model only works well if the PUC can regulate effectively and they questioned the PUC's current ability to do this. The ownership model was not seen as the root of the problem. Instead the utilities' bias toward capital investments is.

There was some interest in the B-corp model as a way for the utility to access more patient capital that would give them the flexibility to make investments that have a longer return on investment. Stakeholders wondered how each regulatory model would work if utility ownership changed, particularly to a Sustainable B. Corp model.

5.2.8.2 **Renewable Energy and Other Technologies**

Stakeholders explained that Hawaii's solar industry was going strong under the net metering program but that it has been negatively impacted by the end of that program. As a result, smaller, local companies have been most severely affected. The solar industry is now focused on energy storage, mainly because it is required under the current regulatory context.

One stakeholder mentioned that there seems to be an overemphasis on the RPS when the focus should be more generally on larger goals like carbon reduction and affordability.

Stakeholders noted that the changes to the net metering program have resulted in substantially decreased opportunities for individuals to access DERs as a strategy to reduce their costs of electricity. However, DERs and microgrids are both considered good options for the Big Island.

5.2.8.3 **The HECO Companies**

The HECO Companies were seen by some as investing substantial time and resources in interacting with the community, particularly on the neighbor islands. Some mentioned that communities on the neighbor islands question why IPPs are developing projects instead of the utility as they have no relationship with the IPPs and they are viewed as outsiders instead of neighbors that the community will interact with on a long-term basis. IPPs are considered by some to be unaware of the sensitivities in each community.

One stakeholder felt that a cultural shift is needed within the utility and that the HECO Companies need to understand better and be more responsive to customers, to operate as a platform that encourages innovation, be more agile, and support a robust DER market.

Some stakeholders recognized that it is valuable for the utility to be a partner in large-scale projects but that it is currently difficult to work with the HECO Companies.

5.2.8.4 **Uniqueness of Hawaii**

Stakeholders explained that Hawaii is unique from other systems. First, there are isolated grids on each island, and each is relatively small systems. The small size of the grid on neighbor islands has resulted in little interest from developers. There are unique cultures on each island with communities having different goals. Stakeholders explained that examples of regulatory models in other locations are not relevant to Hawaii because other areas have access to a larger grid which makes it easier to take risks.

Hawaii is a rural state and stakeholders explained that it is not useful for the focus of regulatory changes to be on creating markets that only work in larger states with more liquidity and market actors. Rural areas like Hawaii do not have the liquidity necessary for these market-based models to function well. In general, stakeholders pointed out that it can take a long time for anything to be developed in Hawaii and that it is vital for any results of this analysis to be actionable. One stakeholder explained that energy planning is a complicated process and that it can be especially difficult to develop any project on the Big Island which further complicates the planning process.

5.2.8.5 **Non-wires Alternatives**

While some stakeholders did not see non-wires alternatives as an option that would work well in Hawaii, others saw benefit in disaggregating generation and wires. They felt that this would address the problem of the utility operating as a monopoly and monopsony by creating competition.

5.2.8.6 **Stakeholder Engagement**

Stakeholders noted that the stakeholder process for this analysis could be influenced by "those who speak most loudly" and not represent the diverse interests and priorities of the communities on each island. Regardless of the model that the PUC decides to adopt, it is imperative that the changes are messaged well to the community, or any change will not be successful.

5.2.8.7 **Regulatory Levers**

One stakeholder explained that for regulation changes to be impactful, there will need to be multiple levers implemented. Currently, the PUC's primary lever is regulating what is allowable for a utility to rate base. It is possible for PBR to be implemented to include basic operations metrics (e.g., call center response times, interconnection times, etc.) that are easily measurable and auditable and are not open to interpretation. These types of levers have only a minimum impact on increasing the value to the system, so they should be limited in use.

One stakeholder pointed out that if too much of the utilities' profits are tied to incentive mechanisms, the utility may focus their performance on these metrics and other areas of operation could suffer. The PUC will need to be careful in establishing metrics and implementing PBR to avoid unintended consequences. To address this, it would be useful to expand the incentive metrics beyond operational areas. However, these metrics would be much more difficult to measure, particularly any novel metrics.

A third lever is shared savings where the utility is given credit for their actions to reduce the rate base. Previous proposals related to this have included too large of a reward for the utility, but the reward should be just large enough to make it worthwhile for the utility to take action. This can be very valuable for the utility because there are low-cost options that they can implement to reduce the rate base. For example, the PUC has implemented a version of this with a new renewable request for proposals ("RFPs") where the utility can keep some of the savings they achieve if they sign a contract for an RFP that is below the price that the PUC has established for renewable RFPs.

A potential concern with this, however, is that it can be challenging to track and measure where savings begin and if there are unnecessary delays in project deployment which would impact when the savings should have occurred. Penalties can be an effective way to mitigate this risk. The fourth lever to consider is the RPI-X model of PBR. The stakeholder viewed this as a critical component for success in revising the regulatory model to be more effective. For example, it was stated that there "is a ton of bloat" in the HECO Companies that could be reduced through efficiency improvements, specifically middle management. If all of this is implemented well, the rate base will continue to grow, but primarily on the grid-side as there is a shift toward non-utility distributed generation. The grid would then shift from being a "giant battery" to a "giant interconnection." If this happens, the rate base will increase through sales will decrease, so opportunities to increase sales, like from the electrification of transportation, will be very important.

5.2.8.8 **Other Topics and Concerns**

- Customers should own their data as data sharing will be essential to open access to the grid.
- It was noted by multiple stakeholders that there are broader community goals than just clean energy, including a sustainable economy, but that regulatory requirements on the utility cannot influence all of these goals.
- Some stakeholders felt that it is not realistic for unique regulatory models to be put in place on different islands.
- One stakeholder explained that electricity is a public good and that the utilities providing electricity should be accountable to the people they serve.
- Regardless of the model, it is vital for rate design to be considered. The utilities have been maximizing fixed costs as a reaction to solar. While economists would recommend

implementing time of use pricing to address this, because it may not be that reducing peak demand is the priority now. Instead, rate design should consider that a goal is increased flexibility over time as the grid moves toward being a giant interconnection.

- One stakeholder would like to see the HECO Companies operate more as a platform and technology provider.
- Many stakeholders brought up electrification of the transportation sector as an important topic that should be considered in any regulatory model revision.
- Some stakeholders were interested in understanding how a hybrid of regulatory models may work best for Hawaii.
- It was noted that consumer priorities are not monolithic and can vary substantially, with different groups prioritizing different functions for the utility (e.g., LMI focus, increased choice for consumers, reliability, affordability, resiliency, etc.).

6 Conclusion

While the discussions at each workshop were unique as stakeholders expressed their priorities and concerns, there were some themes that came up multiple times during the two weeks, namely:

- reliable electricity is a priority, and the current regulatory model has been successful at ensuring utilities provide reliable service;
- minimizing rates now and in the future is a priority;
- that stakeholders greatly value the ability to be engaged in and influence utility decisions to ensure they are aligned with community needs;
- there is much interest in improving resiliency in the electrical grid across the state, particularly in relation to severe storms;
- there is demand for more renewable energy, from more diverse sources, and for more opportunity for a customer-sited generation;
- the regulatory model must allow for and encourage innovation so that the utility can meet its goals in the most cost-effective manner;
- there is concern that the current regulatory model does not allow for the competition in generation necessary for generation to be developed in the most cost-effective way;
- that any model must consider the equity of costs and access to renewable resources as there is concern that grid defection is impacting the LMI community the most.

6.1 Status Quo

All stakeholders agreed that the current regulatory model results in the provision of reliable electricity to the majority of the state, though there was concern about grid resiliency. Across the state, stakeholders believed that this model has not been successful in minimizing electric rates.

Many stakeholders expressed dismay over the lack of community involvement in the utility decision-making process required under the status quo and showed that the utility is not incentivized to take action or make investments in line with community priorities. Some suggested that increasing representation from each island on the PUC would be a good first step to ensuring that priorities from each island are addressed. Some stakeholders explained that this model does not allow sufficient access to the grid for IPPs and does not sufficiently incentivize investments in renewables. Overwhelmingly, stakeholders discussed that the PUC does not have adequate resources to handle its current tasks.

6.2 HERA

In general, stakeholders did not think that HERA would be a good solution for Hawaii. While many noted that it might increase grid access and increase deployment of renewables, a majority of stakeholders thought that HERA would be redundant and increase overall costs.

6.3 ISO

Though it was recognized that an ISO would increase competition, stakeholders agreed that it would be too costly and that the market is too small in Hawaii for an ISO to work.

6.4 DSPP

Stakeholder opinions varied considerably regarding a DSPP model. While many explained that this model would not work in Hawaii, others saw it as a way to increase competition and deployment of DERs. Many stakeholders mentioned that the costs would be too high, particularly the necessary up-front investments required to implement this model.

6.5 PBR

Stakeholders were supportive of using incentives under PBR to encourage utilities to make investments and take actions that are in line with community and policy goals. The potential metrics discussed varied greatly and included cost stabilization, cost equity, increased renewables, incorporation of community priorities, reliability, and resiliency. Multiple stakeholders suggested that it would be critical for representatives from each island to be involved in designing the metrics. There was general agreement that linking utility revenues to performance would be beneficial.

Many stakeholders highlighted that it would be difficult to design and implement PBR well and there was substantial concern about unintended consequences that would result if it is not designed well. As a result, some stakeholders explained that it might be too risky. Preferences varied from a PBR model that would create minor adjustments to the status quo to one that would result in a major overhaul of the system.

6.6 Lighter Regulation of Co-ops

There was support for lighter regulation of co-ops, mostly from stakeholders on Kauai. Many stakeholders said that KIUC has demonstrated the ability to manage and operate the utility well and that PUC regulations are unnecessary. Some stakeholders suggested that Hawaii follow the example on the mainland where co-ops are not regulated as heavily as IOUs. Stakeholders on Kauai noted that a reduction in regulations would reduce costs for both KIUC and the PUC.

6.7 Future Stakeholder Engagement Opportunities

The results from these workshops and the other stakeholder engagement conducted throughout this project will be incorporated into the analyses and the final report, to be submitted to DBEDT in October 2018. Feedback will be collected over the course of the project. All feedback related to the regulatory model analysis that is received by August 31st, 2018 will be summarized and added as an addendum to this report. All other feedback will be incorporated into future reports submitted under this project.

The Project Team will continue to engage with stakeholders to keep them apprised of the status of the project and to receive their input related to the project. The Project Team will be conducting stakeholder workshops in the fall of 2018 to provide an overview of the results of the analysis.

7 Appendix A: Overview of Regulatory Models

The workshops participants were provided with a worksheet providing a high-level overview of different regulatory models. The worksheet is listed on the following two pages.

Hawaii Utility Regulatory Models Community Workshops
June 12-22, 2018

This worksheet is provided as a reference on different utility regulatory models. If you choose to, please use this sheet to record your thoughts on potential regulatory models and hand it to your facilitator to be recorded as feedback.

Name and Organization (optional):

Overview of Regulatory Models

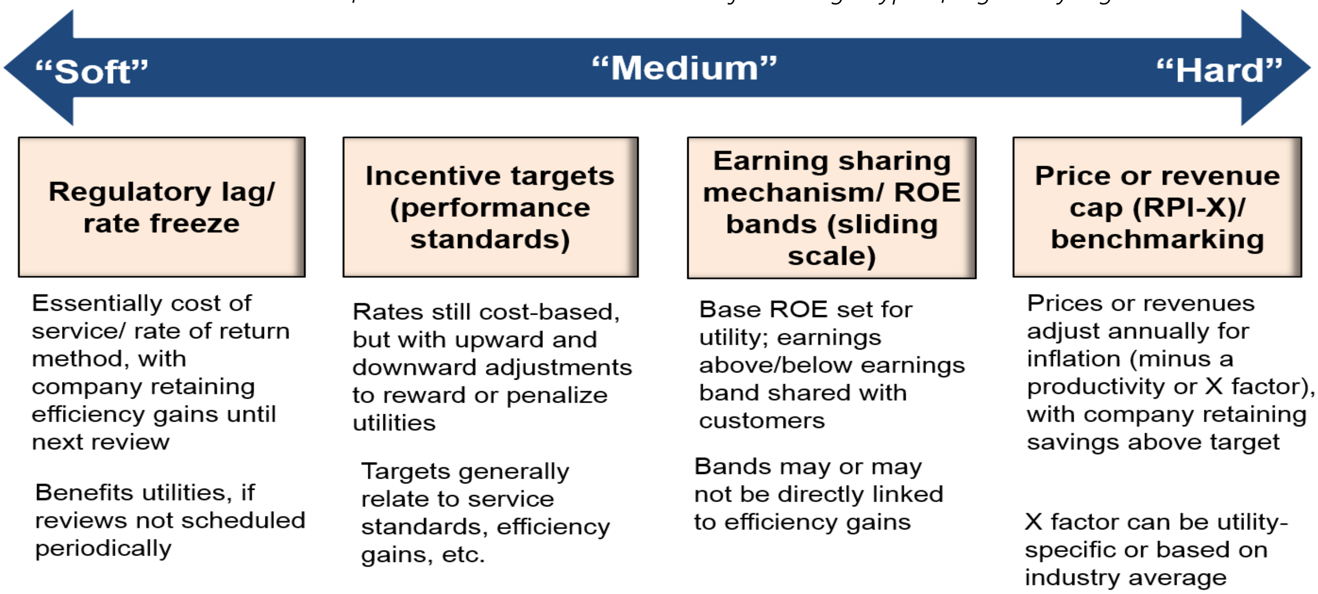
Model	Description
Status Quo (Cost of Service; PUC regulation of vertically-integrated utilities)	Incumbent utilities own and operate all generation, transmission, and distribution assets and are regulated by the PUC. Currently, HECO utilities are permitted to collect rates that are based on their costs of providing electric service, plus an allowed return.
Hawaii Electricity Reliability Administrator (HERA)	HERA would be a new entity that would be charged with ensuring reliability and grid access. This new organization would be formed through existing state law and would support the PUC.
Independent System Operator (ISO)	A new entity would be formed to perform the day-to-day operation of the electric grid and manage resource planning and other important grid functions. This would not entail any changes in the ownership of any utility generation, transmission, and distribution assets.
Distribution-Focused Regulation	A Distributed System Platform Provider (which could also be a utility) would own the distribution system and would facilitate access to competitive third-party distributed energy resource providers.
Performance-Based Regulation (PBR)	PBR would replace or augment cost-of-service regulation and reform the way that utilities collect revenue by tying revenues more closely to the utility's performance in (i) achieving state policy goals, (ii) ensuring greater cost control, (iii) making efficient investments, and (iv) safeguarding fair distribution of risks between utilities and customers.
Decreased Regulation of KIUC	The PUC would no longer regulate various elements of KIUC's operations, including rate-setting. The PUC would continue to regulate HECO utilities.

Model	What strengths do you think this model has?	What weaknesses do you think this model has?
Status Quo		
HERA		
Independent System Operator		
Distribution-Focused Regulation		
Performance-Based Regulation		
Decreased Regulation of KIUC		

What other comments do you have on different regulatory models?

Performance-Based Regulation Detail

PBR exists as a continuum with "soft" to "hard" mechanisms and not just a single type of regulatory regime.



PBR Component	What strengths do you think this approach has?	What weaknesses do you think this approach has?
Provide rewards for the utility if they achieve set targets		
Penalize the utility for not meeting certain performance targets		
Share earnings between utility & customers		
Remove utility incentives between capital and operating expenses		
Cap utility prices or revenues, and allow the utility to benefit from cost savings		

What types of outcomes or metrics do you think PBR should encourage? Examples: Reliability and availability, Customer satisfaction, Safety, Environmental impact (e.g., RPS goal), Social obligations, Innovation

What other comments do you have on PBR

8 Appendix B: Outreach Flyers

All outreach flyers can be accessed at the links below.

City and County of Honolulu

- Kailua: https://www.dropbox.com/s/s2fsob0pjum702i/Kailua.docx?dl=0
- Honolulu: https://www.dropbox.com/s/jpdd5l0vo2oii65/Honolulu.docx?dl=0

Hawaii County

- Hilo: https://www.dropbox.com/s/sbithk48afbmu1j/Hilo.docx?dl=0
- Kona: https://www.dropbox.com/s/5luewztsbk4oxdr/Kona.pdf?dl=0

Kauai County

- Lihue: https://www.dropbox.com/s/om0wm3b7xgnn2oj/Lihue.docx?dl=0

Maui County

- Kaunakakai, Molokai: https://www.dropbox.com/s/8gcgiydm2otx68h/Kaunakakai.docx?dl=0
- Lanai City, Lanai: https://www.dropbox.com/s/brlly5m29pdvn8t/Lanai.docx?dl=0
- Wailuku, Maui: https://www.dropbox.com/s/kw6wo98dve7u4ol/Wailuku.docx?dl=0

9 Appendix C: Press Release

HAWAII STATE ENERGY OFFICE SCHEDULES COMMUNITY MEETINGS ON UTILITY MODEL STUDY

Posted on Jun 12, 2018 in News Releases

For Immediate Release: June 12, 2018

HONOLULU – The Hawaii State Energy Office (HSEO) will host a series of community meetings across the state starting tomorrow to gather community input for the second phase of a study being done on future models for utility ownership and regulation in Hawaii.

The latest round of community meetings will focus on the future of electric utility regulatory models, including performance-based regulation and the role the Public Utilities Commission plays in achieving state energy goals. The first series of community meetings held last October addressed the issue of utility ownership.

HSEO, a division of the State Department of Business, Economic Development and Tourism (DBEDT), is undertaking the study at the request of the Hawaii State Legislature to evaluate the costs and benefits of various electric utility ownership models, as well as the viability of various utility regulatory approaches to help Hawaii in achieving its energy goals. The study will examine scenarios for each of Hawaii's counties.

HSEO has contracted with Boston-based London Economics International (LEI) to carry out the study, which is expected to be completed by January 2019. LEI and subcontractor Meister Consultants Group will lead the community meetings for June 13-22. The meeting schedule is as follows:

Honolulu County:

- Kailua, June 13, 5:30 – 7 p.m., Enchanted Lake Elementary School Cafeteria, 770 Keolu Dr. Kailua Event Flier and Registration
- Honolulu, June 14, 6:00 – 7:30 p.m. Foreign Trade Zone #9, Homer Maxey Conference Center, 521 Ala Moana, Suite 201. Honolulu Event Flier and Registration

Kauai County:

- Lihue, June 15, 5:30 – 7 p.m. Kauai High School Cafeteria, 3577 Lala Rd. Kauai Event Flier and Registration

Maui County:

- Wailuku, June 18, 6:00-7:30 p.m. Waikapu Community Center, 22 E Waiko Rd. Maui Event Flier and Registration

- Kaunakakai, June 19, 6:00-7:30 p.m. Mitchell Pauole Center Main Hall, 90 Ainoa St. Molokai Event Flier and Registration
- Lanai City, June 20, 6:00-7;30 p.m. Lanai Community Center, Eighth St. and Lanai Ave. Lanai Event Flier and Registration

Hawaii County:

- Hilo, June 21, 5:30 – 7 p.m. Waiakea High School, 155 W Kawili St. Hilo Event Flier and Registration
- Kailua-Kona, June 22, 5:30 – 7 p.m. NELHA Research Campus, Hale Iako Building, 73-970 Makako Bay Drive. Kailua-Kona Event Flier and Registration

Community members planning on attending the meetings are encouraged to RSVP at the link above. Light refreshments will be served. Those unable to attend a meeting in person can view a copy of the material presented, which will be posted on HSEO's website energy.hawaii.gov/utility-model after the meetings, and may participate by submitting feedback via email to: dbedt.utilitybizmodstudy@hawaii.gov. Questions about the meetings or the study can be emailed to the same address.

10 Appendix D: Email Invitation Text

Stakeholders across the state that had been engaged with this project in the past, expressed interest in participating, or were identified through discussions with DBEDT and the Core Group were sent the following email invitation from DBEDT.

INVITATION TEXT:

Under the direction of the Hawaii State Legislature, the Hawaii State Energy Office (HSEO) within the Department of Business, Economic Development, and Tourism is undertaking a study on the future of electric utility regulatory models in Hawaii.

HSEO has contracted with Boston-based London Economics International to carry out the study, which is expected to be completed by January 2019.

As a part of this study, you are invited to share your thoughts and input on the future of electric utility regulatory models including performance-based regulation and the role the Public Utilities Commission plays in achieving state energy goals, including achieving 100% renewable energy and minimizing rate increases. We welcome everyone's participation and request that you register via the link below. Light refreshments will be served.

The meetings will occur statewide, June 13 through June 22, 2018.

Register today! (linked to: http://hawaiistateenergyoffice.cmail20.com/t/t-l-uithpy-xpskrll-d/)

If you have any questions or are not able to attend a meeting and would like to provide feedback via email, please contact us at dbedt.utilitybizmodstudy@hawaii.gov. The meeting materials will be posted on the Community Meetings page.

We look forward to your participation and input.

11 Appendix E: Scope of work to which this deliverable responds

Task 2.2.5 Outreach Plan and documentation of results of public outreach on each island served by an electric utility. CONTRACTOR shall develop and carry out an outreach plan approved by the STATE to solicit public input from each island currently served by an electric utility on the results of TASKS 2.1.1 through 2.2.4.

DELIVERABLE FOR TASK 2.2.5. CONTRACTOR shall provide all work to support an outreach plan for public input, designing and conducting outreach processes and activities with stakeholders, and incorporate feedback throughout the duration of the project as described in Proposal Scope TASK 2.2.5. CONTRACTOR shall provide a written Outreach Plan to the STATE for approval prior to carrying out the plan. CONTRACTOR shall provide documentation of results of public outreach on each island in MS Word and spreadsheets in MS Excel. CONTRACTOR shall submit deliverable for TASK 2.2.5 to the STATE for approval.

Ranking and recommendation of regulatory models for further review

Prepared by London Economics International LLC and Meister Consultants Group for the Hawaii Department of Business, Economic Development, and Tourism

September 6, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study to assess the costs and benefits of different electric utility ownership models and regulatory models that could support the State of Hawaii in achieving its energy goals ("DBEDT Study"). As part of the engagement, this working paper provides a ranking process and rationale for the recommendation of three regulatory models for further consideration. The three regulatory models recommended for further analyses for counties served by the HECO Companies include: (1) Hybrid model, (2) Conventional performance-based regulation ("PBR") with Light Hawaii Electricity Reliability Administrator ("HERA") model, and (3) Outcomes-based PBR model. For Kauai, the Project Team selected (1) the HERA model, (2) Independent Grid Operator, and (3) Lighter PUC regulation for further review.

Table of Contents

London Economics International LLC
717 Atlantic Ave., Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Cherrylin Trinidad/Utsav Dhoj Adhikari
617-933-7229
cherrylin@londoneconomics.com

Table of Figures

List of acronyms

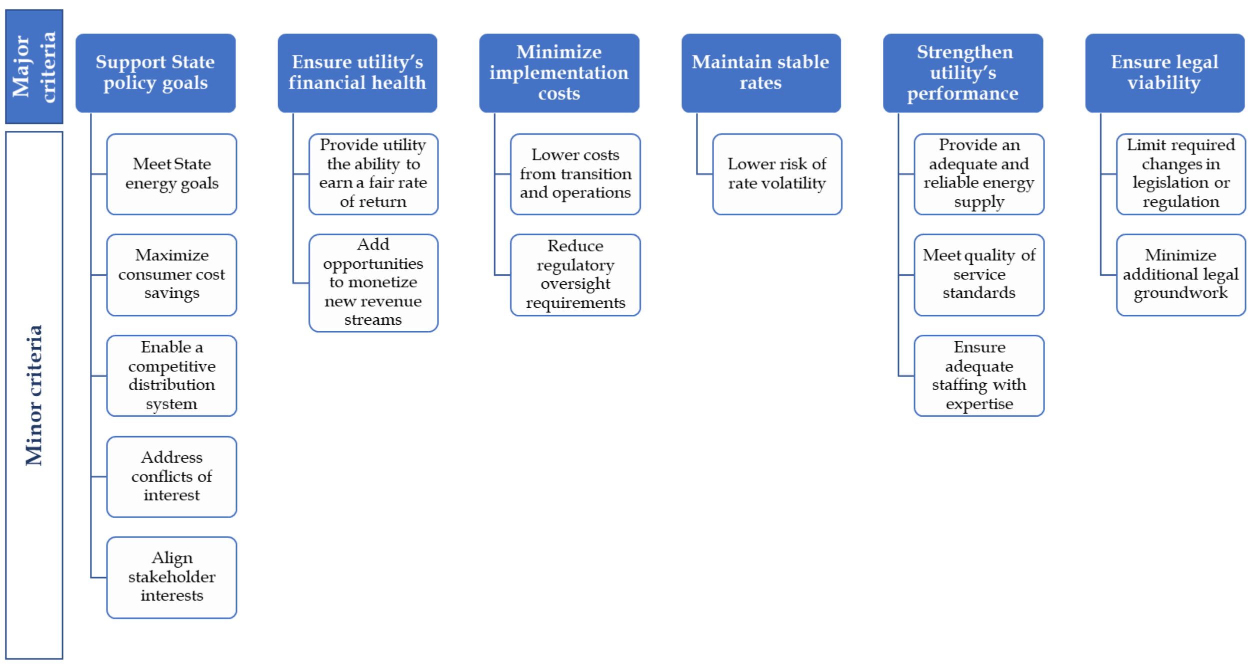
DBEDT	Hawaii Department of Business Economic Development and Tourism
DER	Distributed Energy Resource
DG	Distributed Generation
DR	Demand Response
DSPP	Distributed System Platform Provider
EE	Energy Efficiency
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
HECO	Hawaiian Electric Company, Inc.
HELCO	Hawaii Electric Light Company, Inc.
HERA	Hawaii Electricity Reliability Administrator
HSEO	Hawaii State Energy Office
IGO	Integrated Grid Operator
IOU	Investor-owned Utility
IPPs	Independent Power Producers
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MCG	Meister Consultants Group
MECO	Maui Electric Company, Ltd.
PBR	Performance-based Regulation
PIMs	Performance Incentive Mechanisms
PUC	Public Utilities Commission
RAB	Regulated Asset Base
RPS	Renewable Portfolio Standards
T&D	Transmission and Distribution
TOTEX	Total expenditure

1 Executive summary

The Hawaii Department of Business Economic Development and Tourism ("DBEDT") contracted London Economics International LLC ("LEI"), together with Meister Consultants Group (the "Project Team"), for a study that will assess the costs and benefits of various electric utility ownership models and regulatory models that can support the State in achieving its energy goals. This working paper, which corresponds to Task 2.2.6 in the project scope of work, provides a ranking of the regulatory models introduced in Task 2.1.1. The ranking of the regulatory models was undertaken so that the three most feasible and viable regulatory models may be considered for more in-depth analysis in subsequent tasks.

The Project Team developed a set of major criteria with minor sub-criteria (based on the State-specified criteria and Scope of Work), which guided the assessment. Figure 1 below shows the set of major and minor criteria used to assess the regulatory models.

Figure 1. Major and minor criteria



The Project Team scored the potential performance of the regulatory models on each evaluation criterion as positive, neutral, or poor, subject to certain assumptions. Moreover, within these major criteria, the ranking methodology weighed some minor criteria more heavily than others based on the relevance of the criterion to the goals of the DBEDT Study, implications toward the achievement of other standards, and value to stakeholders**.** The weights of all minor criteria total 100%. Figure 4 summarizes the weights of these criteria.

Based on the analysis, guided by the ranking, the Project Team concludes that the three most promising regulatory models for Honolulu, Hawaii, and Maui Counties for further review are:

1) **Hybrid model** [combination of Outcomes-based Performance-Based Regulation ("PBR"), Distributed System Platform Provider ("DSPP"), and Integrated Grid Operator ("IGO")],
2) **Conventional PBR** with a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**") model, and
3) **Outcomes-based PBR** model.

As discussed in previous working papers, **Outcomes-based PBR,** which is the most comprehensive PBR regime, seeks to incentivize the utility toward beneficial outcomes for society. These potential outcomes include i) enhancing customer experience, (ii) improving utility performance, (iii) achieving public policies and goals, and (iv) maintaining healthy financial performance. Under this PBR regime, utilities have flexibility on preferred solutions and strategies to attain those outcomes. Other mechanisms such expanded Performance Incentive Mechanisms ("PIMs"), Earnings Sharing Mechanism ("ESM"), total expenditure ("totex") approach,[1] and more stringent reporting regimes are included under the Outcomes-based PBR.[2]

Conventional PBR with Light HERA would combine a PBR regulatory regime with a Light HERA entity to oversee the interconnection process and reliability planning. Under Conventional PBR, the revenue requirements of the utilities are based on an indexing formula (inflation less productivity factor) for the second and third years of operation. Mechanisms such as an expanded set of PIMs, ESM, and totex approach are included under this PBR regime. The Light HERA entity would perform the task of an ombudsman, for example, stepping in for dispute resolution when required.

The Hybrid model assumes an independent entity (i.e., Independent Grid Operator or "IGO") would manage the dispatch and planning functions of both the transmission and distribution assets. Moreover, under this model, the utilities would serve as the Distributed System Platform Provider ("DSPP"), providing open access to Distributed Energy Resources ("DERs") and other providers offering energy management or customer data analytics services. Customers, service providers, DERs, and utilities conduct transactions of energy and services on the modernized grid platform provided by utilities. For the utilities to remain effective in their traditional functions even as a DSPP, an Outcomes-based PBR would also be implemented. The utilities,

---

[1] Under a totex approach, there is no distinction between the capex and operating expenditures as the utilities are incentivized to consider the whole life costs, rather than choose between a capital expenditure or an operating expenditure solution.

[2] Task 2.1.1 (Introduction to the Regulatory Models) provides more description on the mechanisms under an Outcomes-based PBR.

Public Utilities Commission ("PUC"), and stakeholders would determine appropriate outcomes that the utilities need to achieve by the end of the regulatory period.

The Project Team's separate analysis conducted for Kauai County concludes that the three most promising regulatory models for Kauai County are:

1) **HERA model**,
2) **IGO**, and
3) **Lighter PUC Regulation**.

Under the **HERA model**, the PUC's role in ensuring grid access and reliability would be transferred to HERA. The HERA, as an entity, was authorized by the Hawaii State legislation (Act 166) in 2012.

The Project Team envisions the **IGO** as an entity that combines the work of an Independent System Operator and a Distribution System Operator. It would assume responsibility for resource planning, oversee system operations (including dispatch), and determine the investment requirements for both transmission and distribution networks. While the utility would continue to operate as a co-op, its planning and dispatch functions would be assumed by the IGO.

A **Lighter PUC Regulation** model would primarily serve to reduce Kauai Island Utility Cooperative's ("KIUC") regulatory burden. All utility functions and operations would remain the same, but KIUC would no longer be required to obtain PUC approval for rate changes, supply contracts, and capital expenditures unless rates increase, or capital expenditures surpass, a certain threshold. The PUC would still remain involved in dispute resolution.

These three regulatory models will be subject to additional analyses in Tasks 2.3 to 2.5.

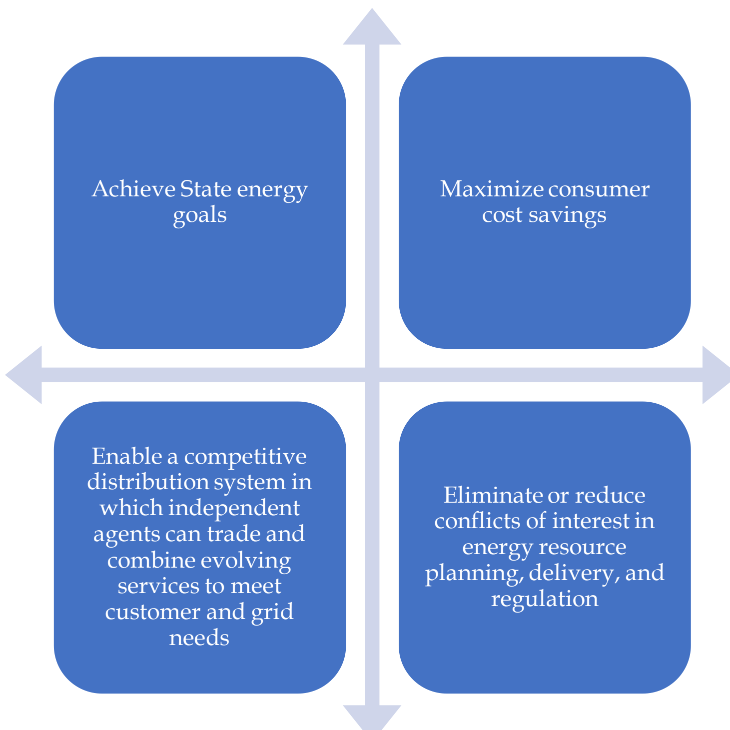
2 Introduction and scope

2.1 Project description

DBEDT was directed by the State's legislature to commission a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models which can best facilitate the achievement of the State's energy goals. The Project Team, through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The project aims to evaluate different utility ownership and regulatory models—based on the State's key criteria—and determine which among them can best be adapted in Hawaii[5] (Figure 2).

Figure 2. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

---

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models that serve each county of the state.

Furthermore, it will also aid in identifying the process that must be followed in forming such ownership and regulatory models as well as determining whether such models would create synergies in the sector. Such synergies can be appreciated in terms of increasing local control over energy sources serving each county, diversifying energy resources, promoting economic development, reducing greenhouse gas emissions, improving system reliability and power quality, and lowering costs to all consumers. [6]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Task 2.2.6 in the project scope of work. It builds on several previous deliverables, namely, introduction of the regulatory models (Task 2.1.1), high-level assessment based on the state goals (Task 2.2.1), current markets using such regulatory models (Task 2.2.2), potential stranded costs (Task 2.2.4), and high-level feasibility of ownership models (Task 2.2.3).

Moreover, the rankings in this deliverable take into consideration feedback received as part of the stakeholder engagement efforts (Task 2.2.5 - Community Discussions on Regulatory Models), as well as numerous one-on-one meetings with stakeholders. These stakeholder engagement efforts elicited valuable feedback and underscored the importance of the key criteria that guided the ranking design and weighting.

Finally, this task will serve as the precursor to further analysis in subsequent tasks:

- identification of steps, costs, and projected timelines required by the change from the current regulatory model to the recommended regulatory models (Task 2.3.1);
- analysis of Hawaii law and history to determine the regulatory and legislative changes needed in the implementation of the recommended regulatory models (Task 2.3.2);
- identification and assessment of the impact of known or potential financial and operational risks for different stakeholders under each regulatory model (Task 2.3.3);
- evaluation of how each regulatory model could impact state agencies such as the Public Utilities Commission and stakeholders such as the Consumer Advocate (Task 2.3.4);
- estimated potential of each model in increasing distributed energy resources, demand response, system security, reliability, and resilience and meeting Hawaii's RPS milestones through 2045 (Task 2.4.1);

[6] Hawaii Contract No. 65595. Scope of Services.

- estimated annual revenue requirement (including major costs by category) of each of the recommended regulatory models; comparison of the outcomes of the three regulatory (Task 2.5.1);
- assessment of system average retail rates for an average residential, commercial, and industrial customer (up to 2045) in each regulatory model (Task 2.5.2);
- analysis of how costs differ (as well as an explanation of the revenue requirement calculation) under each regulatory model (Task 2.5.3);
- review of issues that could impact the valuation of an electric utility and identify key risks in utility valuations for each regulatory model (Task 2.5.4); and
- identification of funding mechanisms for each regulatory model (Task 2.5.5).

3 Criteria and methodology

The Project Team determined the ranking by first establishing major categories through which the regulatory models were evaluated. Following this, the Project Team developed "minor categories" or sub-criteria, which further refined the scope of major categories. The Project Team then designed a weighting system to indicate the relative importance of each of the minor criterion. Using existing data, literature, case studies, interviews, and insights gathered from stakeholder workshops, the Project Team determined the final weighting and scoring of the regulatory models. Many of these insights were presented in the previous working papers.[7] This methodology will be discussed in this section.

3.1 Models reviewed

The Project Team initially evaluated nine regulatory models that could be implemented in the counties served by HECO Companies. These counties include Hawaii, Oahu, and Maui. The Project Team reviewed more regulatory models than what was asked for in the Scope of Work to ensure more comprehensive analytical work. More specifically, the Scope of Work required the team to look into five regulatory models:

(1) Status Quo;

(2) Status Quo with increased oversight from Hawaii Electricity Reliability Administrator ("HERA") or the "HERA model;"[8]

(3) Independent System Operator ("ISO");[9]

(4) distribution-focused regulatory model (or the Distributed System Platform Provider or "DSPP model"); and

(5) Performance-Based Regulatory model ("PBR").

[7] These include Task 2.2.1 (which evaluated the regulatory models with respect to State goals), Task 2.2.3 (which provided an initial high-level feasibility overview of each of the regulatory models), and Task 2.2.5 (which produced the results of the stakeholder outreach workshops from June 2018).

[8] A Light HERA was also considered as an alternative option to HERA. Under the Light HERA, HERA (the entity) could act as an ombudsman, an appeals body focused on hosting capacity and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs in order to arbitrage disputes between customers and the utility. See Task. 2.1.1. for a detailed description of the Light HERA.

[9] As discussed in Task 2.2.1, the functions of the ISO and the independent distribution system operator are combined into an Independent Grid Operator ("IGO"). Given the smaller size of Hawaii State's transmission and distribution systems (compared to other jurisdictions), combining these two regulatory models would be more effective and efficient.

However, the Project Team decided to assess three PBR variants—Light, Conventional, and Outcomes-based—because PBR is an umbrella term that covers a wide range of mechanisms and combinations of these mechanisms:[10]

- **Light PBR** would feature expanded Performance Incentive Mechanisms ("PIMs") with rewards and financial consequences, as well as the current Earning Sharing Mechanism ("ESM").

- **Conventional PBR** would use an indexation formula and a revenue cap to determine the revenue requirements of the utilities, together with PIMs, a symmetrical ESM, and a total expenditure ("totex") approach in treating expenditures.[11]

- **Outcomes-based PBR** would focus on the outcomes related to enhancing customer experience, improving utility performance, achieving public policies and goals, and attaining healthy financial performance. It also features an expanded set of PIMs, an ESM, and longer regulatory period (5 years),[12] among the other features of this PBR.

Furthermore, the analysis in Task 2.2.1 (Evaluation of Regulatory Models Relative to State Criteria) showed that combining some of the regulatory models would be more effective in facilitating the achievement of state goals. In particular, two combinations stand out given the state's goals:

(1) Hybrid Model - a combination of the Outcomes-based PBR, IGO, and DSPP; and

(2) Conventional PBR with Light HERA.

The Project Team also assessed five models for Kauai County, namely:

(1) Status Quo;

(2) HERA model;

(3) IGO;

(4) DSPP; and

(5) Lighter PUC regulation.

---

10 Task 2.1.1 (Introduction to the Regulatory Models) provides a detailed discussion of the difference between these three PBR models.

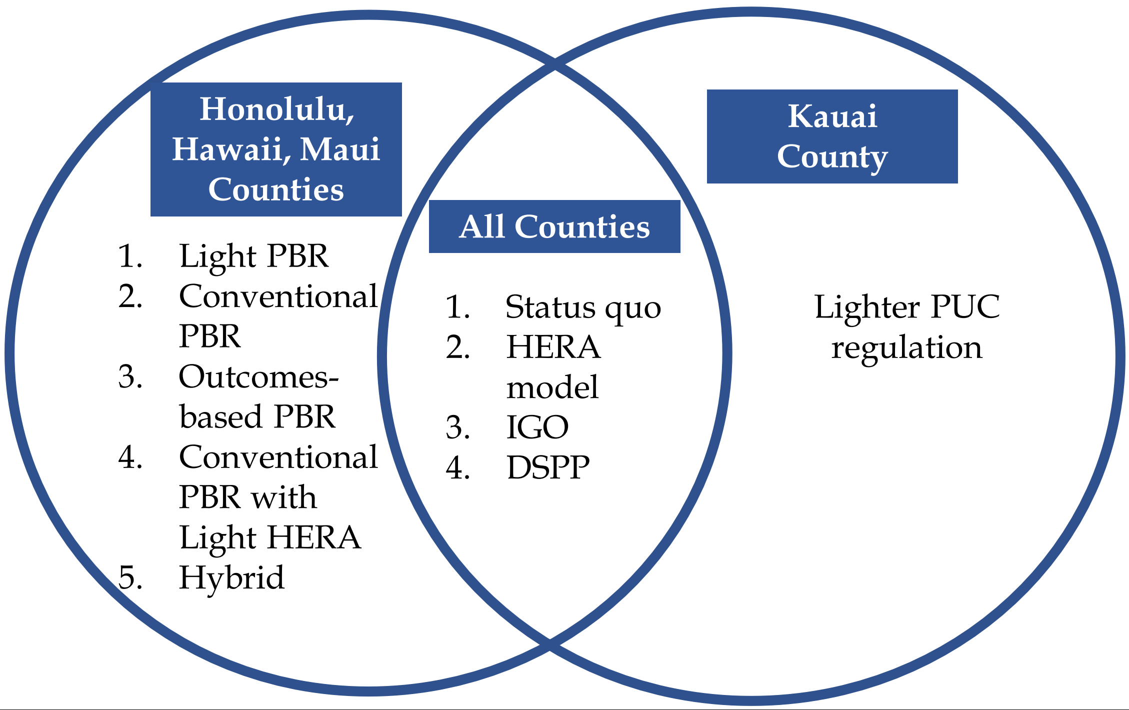
11 See Footnote 1.

12 In addition to these, the Outcomes-based PBR also incorporates the totex approach and a more stringent reporting requirement. It also requires utilities to submit capital expenditure and asset plans in its PBR submission.

PBR was not included in the evaluation for Kauai County because cooperatives are excluded from the PBR legislation. The Lighter PUC Regulation was added as an option since KIUC *"considers and potentially seeks increased exemption from regulation by the PUC."*[13]

This analysis identified three regulatory models that are considered for further analysis in subsequent tasks. Figure 3 shows the regulatory models reviewed for the different counties.

Figure 3. Regulatory models reviewed



3.2 Criteria and major evaluation categories

The Project Team developed and categorized several evaluation criteria, taking into consideration the Scope of Work's specified criteria. Stakeholder feedback generated during the community outreach and one-on-one meetings was also taken into consideration. Figure 3 shows the list of the major and minor criteria, which are discussed below.

[13] KIUC. *Strategic Plan Update 2016 – 2030.* January 31, 2017 adopted. Page 5.

Figure 2. Major and minor criteria

Support State policy goals	Ensure utility's financial health	Minimize implementation costs	Provide stable rates	Strengthen utility's performance	Ensure legal viability
• Meet State energy goals • Maximize consumer cost savings • Enable a competitive distribution system • Address conflicts of interest • Align stakeholder interests	• Provide utility the ability to earn a fair rate of return • Provide financial incentives	• Lower costs from transition and operations • Reduce regulatory oversight requirements	• Lower risk of rate volatility	• Provide an adequate and reliable energy supply • Meet quality of service standards • Ensure adequate staffing with expertise	• Limited required changes in legislation • Minimize additional legal groundwork

3.2.1 Criterion 1: Support State policy goals

Each regulatory model was scored based on its ability to help achieve the policy goals established by the legislation in House Bill 1700, which provided the directive for this Study. These study criteria, introduced in Task 1.2.1., include the following and are further discussed below:

1. achieve State energy goals;
2. maximize consumer cost savings;
3. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and
4. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.[14]

3.2.1.1 Achieve State energy goals

This sub-criterion focuses on the regulatory model's ability to enable the achievement of Hawaii's Renewable Portfolio Standard ("RPS") target, which is to procure 100% of net electricity sales from renewable energy by 2045. Hawaii's utilities have made significant strides toward the achievement of the 100% renewables target under the existing regulatory structure. The Project Team evaluated the proposed alternative regulatory models based on additional or alternative levers available in each model. Such levers are meant to encourage compliance through incentives

[14] Hawaii State Energy Office. *Utility Model Study*, http://energy.hawaii.gov/utility-model (accessed August 21, 2018).

and/or penalties and address barriers to the growth of utility-scale and customer-sited renewable energy, battery storage, energy efficiency ("EE"), and demand response ("DR")—all of which help in assessing whether they would have a larger or smaller potential in facilitating the achievement of the State's energy goals.

3.2.1.2 Maximize consumer cost savings

> State energy goals include the State of Hawaii's 100% renewable energy target as well as the five Energy Policy Directives of the Hawaii State Energy Office ("HSEO") which consist of:
>
> 1. diversifying Hawaii's energy portfolio;
> 2. connecting and modernizing Hawaii's grids;
> 3. balancing technical, economic, environmental, and cultural considerations;
> 4. leveraging Hawaii's position as an innovation test bed; and
> 5. promoting an efficient marketplace, that benefits producers and consumers.
>
> Source: Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at: https://energy.hawaii.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf

The Project Team evaluated the regulatory models based on how each model addresses the costs of producing and delivering electricity and the incentives for the improvement of operational efficiency.

Depending on the regulatory model, additional costs incurred by utilities or the oversight bodies (such as fees that help cover the costs of establishing and operating the regulatory agencies, incentive payments, or cost of regulatory proceedings) might be passed on to ratepayers. Therefore, the choice of a regulatory model for Hawaii must consider the additional costs that each model would entail alongside the potential savings that it can generate.

3.2.1.3 Enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs

For this sub-criterion, the regulatory models were scored based on whether they facilitate open grid-access at the distribution level for customers, DER providers, and other service providers. One of the goals articulated in House Bill 1700 is to *"enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs."* This goal is anchored on a desire to modernize Hawaii's electric grid by taking advantage of technological advancements in both software capabilities and renewable resources. Increased penetration of DERs opens new opportunities for energy management and other additional services based on advanced analytics.

3.2.1.4 Address conflicts of interests in energy resource planning, delivery, and regulation

The Project Team considered how useful each regulatory model is in separating planning, operational control, investment, and ownership to minimize conflicts of interests. The regulated and vertically-integrated monopoly structure of Hawaii's electricity industry can amplify the conflicts of interest in energy resource planning, delivery, and regulation. The potential for conflict of interest between or among different utility functions exists because the utilities control resource planning, grid operations, energy delivery, and a significant share of generation resources. Therefore, there is an inherent incentive in the current regulatory model for utilities to opt for a planning and operations approach that benefits their other business entities. It creates the possibility of a tilted playing field in favor of the utility because IOUs like HECO Companies have a profit-maximization objective. The primary check on the IOUs' self-interest is usually the PUC's regulatory proceedings, putting the utilities and the PUC in an adversarial arrangement.

3.2.1.5 Align stakeholder interests

Under this criterion, the different regulatory models were compared based on whether they include mechanisms that align the interests of utilities, customers, Independent Power Producers ("IPPs"), and policymakers. In any industry, stakeholders can have some interests that are mutually beneficial and others that benefit one at the expense of others. Well-designed regulations encourage behavior that falls in the former category and dissuade that which falls in the latter.

3.2.2 Criterion 2: Ensure utilities' financial health

Under this second criterion, the Project Team assessed how the different regulatory models impact the utilities' ability to earn a fair rate of return and generate additional revenues. The financial viability of the utilities is an important consideration when comparing different regulatory models. In all regulatory models, the utilities are integral parts of the system. Stakeholders (during the outreach meetings) also indicated that they expect the utilities to provide essential electric services. Modernizing Hawaii's electric grid infrastructure and achieving the State energy goals would require sizeable investments. For some of the necessary investments, the utilities remain best positioned to make those investments cost-effectively. Therefore, it is imperative to ensure that utilities can raise funds for capital needs and earn a fair return that allows them to meet their obligations and attract investors.

3.2.2.1 Provide utility the ability to earn a fair rate of return

Under this criterion, the Project Team evaluated how the change in the regulatory model would help ensure that the utilities can earn a fair rate of return. Regulatory changes that limit utilities' revenue or add financial penalties tied to performance could impact the utilities' cost of capital. The utilities' financial viability is reflected in their cost of capital, among other factors. Utilities that operate an efficient business in a stable regulatory environment have better access to capital, which could finance their expenditures. Lower levels of risks, whether real or perceived, usually translate into lower costs of capital and ultimately lower rates. The HECO Companies rely on capital markets for financing, and thus are acutely sensitive to regulatory changes that impact their ability to meet their operational mandates (as defined by the PUC) *and* provide a predictable return to their investors.

KIUC is also exposed to regulatory risks even though it can obtain debt at subsidized rates from specialty lenders and essentially raise equity *for free* (e.g., soliciting patronage capital from its members). As a co-op, KIUC relies on securing subsidized loans to lower its costs of providing service to its members. Even though the loans are subsidized, they have terms and conditions regarding, for instance, minimum levels of interest coverage. Failure to comply with debt covenants would raise its costs of debt and undermine a crucial part of its value proposition to its members.

3.2.2.2 Add opportunities to monetize new revenue streams

Aligning utility incentives with the State's priorities (such as lower electricity bills, reduced dependence on imported oil, and a greater say in utility decision-making) is often discussed in terms of removing specific incentives (for utilities), which result in a detrimental outcome for ratepayers. However, incentives can also be aligned by financially rewarding utilities for investing in or achieving outcomes that benefit the broader community. Utilities do not always benefit financially from actions that create value for the community; sometimes, their traditional revenue streams are even constrained as a result. Therefore, allowing utilities to generate incremental new revenue or providing reward opportunities for such actions would align their interests with the community while also supporting their revenues and financial viability.

Under this criterion, the Project Team assessed whether the regulatory models provide additional revenue streams or financial incentives to the utilities. For instance, PBR models offer financial incentives tied to the utilities' performance. Likewise, a DSPP model opens new categories of potential revenues for utilities. The presence and magnitude of such positive reinforcements could offset, in part or wholly, any increases in the riskiness of the utilities' operations.

3.2.3 Criterion 3: Minimize implementation costs

A change of regulatory model may result in savings on current costs in the long run but also cause additional costs during the transition to, and implementation of, the new regulatory model. Therefore, under this criterion, the regulatory models were compared based on the costs resulting from transitioning and operating the new regulatory model. Aside from the Status Quo (which would not result in incremental costs), the other eight regulatory models require varying degrees of stakeholder engagement, legislative processes, and infrastructure investments. Furthermore, a new regulatory model could also require the PUC to expand its capabilities to provide the necessary oversight.

3.2.3.1 Lower costs from transition and operations

Transitioning to a new model would requires expenditures associated with conducting the necessary studies and stakeholder engagement. Furthermore, there may be additional expenditures related to personnel and infrastructure, both initially and on an ongoing basis. This is particularly true for the IGO and DSPP models because they entail a significant change in how the grid is operated; substantial infrastructure investments and new operational capabilities are necessary to enable those models. The performance targets under PBR models also require some utility investments up-front as well as for regular monitoring and verification, all of which are crucial to the achievement of the goals.

3.2.3.2 Reduce regulatory oversight requirements

A new regulatory model may require the PUC to hire more staff (or external consultants), so it can ensure that the utilities remain in compliance with their new responsibilities. For instance, the PBR models place a significant administrative burden on the regulator, especially during the first generation of implementation. The PUC would need to put together regulatory implementation guidelines, which specify the PBR mechanisms and process. Moreover, the PUC would need to monitor the operational and financial performance of the utilities. On the other hand, the IGO and HERA entities may lower the burden on the PUC, for example, in terms of providing direct oversight on interconnections and reliability.

3.2.4 Criterion 4: Maintain stable rates

This criterion considers the volatility of electricity rates for consumers that may result from a regulatory change. Some of the models may provide rate stability while others might increase rate volatility. Rates could also change drastically between rate cases even without a significant change in regulation. For instance, rates could rise if the costs for utilities increase significantly due to substantial capital investments (e.g., for replacing infrastructure or installing new equipment), or due to the fuel prices, in certain years. One example of a mechanism for stabilizing rates without harming utility financials is to lengthen the regulatory period.

3.2.5 Criterion 5: Strengthen utility's performance

As discussed in previous working papers, the utilities are required to provide adequate and reliable electricity supply, meet the quality of service standards, avoid interruption of service, and conform to the policies set by the legislation. Incentivizing the utilities to improve their performance in these categories is one factor that was considered under this criterion.

Also, as the power sector evolves, the utilities are expected to perform new functions and offer new services. The new responsibilities could fall on the utilities or be transferred to new entities, depending on the model. Even some of the current functions of the utility could be transferred to other entities. There are technical risks in terms of how competent the different bodies are in performing the new tasks or maintaining current standards of reliability and customer service under the new regulatory structures. Therefore, another factor that was taken into account under this criterion is whether additional staffing is required to perform the new responsibilities.

3.2.5.1 Provide an adequate and reliable electricity supply

The Project Team evaluated the regulatory models based on the oversight and enforcement mechanisms within each model to ensure that the grid service continues to meet the standards set by the PUC. The General Order No. 7 (regarding Hawaii's PUC) outlined several standards for electricity service. It mandates essential metrics relevant to future regulatory models.[15] Indices

[15] Department of Regulatory Agencies, State of Hawaii. *Title VII – Public Utilities Commission. Standards for Electric Utility Service in the State of Hawaii, General Order No. 7.* Available at: https://puc.hawaii.gov/wp-content/uploads/2013/04/General-Order-7.pdf

that measure grid reliability include System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"). Maintaining grid reliability will be more challenging as the share of intermittent renewables in the generation mix increases.

3.2.5.2 Meet quality of service standards

The regulatory models were assessed in terms of how utilities under each regulatory model would continually achieve high quality of service standards as required by the PUC. Quality of service includes aspects of customer service and technical services, which involve both interactions and engagements between customers and utilities.

3.2.5.3 Ensure adequate staffing with the required expertise

A smooth transition to the new regulatory model requires staffing with relevant skills and competencies. While it is generally reasonable to assume that there would be a transition phase between regulatory models, some models would need new technical and operational capabilities (such as a distribution-level peer-to-peer transaction platform), resulting in greater operational risk. The Project Team's prior stakeholder engagement workshops revealed concerns about the ability of the PUC and utilities to attract and retain talented staff. This concern may be exacerbated by a transition to regulatory models that are less common nationally and globally, and therefore have smaller talent pools of experienced personnel or require more rigorous training for current staff.

3.2.6 Criterion 6: Ensure legal viability

Legal viability encompasses the overall legal feasibility of each potential new regulatory model and the associated transition process. This includes changes in legislation, regulations, or additional requirements. It also assesses the extent to which the involvement of various actors—whether it be the State legislature, local city councils, or the PUC—is necessary for the establishment of the regulatory model. There may be winners and losers from the transition to a new model. Stakeholders who are dissatisfied with the new model, whether in terms of overall structure or regarding specific details, may challenge the proposed changes before the PUC or the courts.

3.2.6.1 Limit required changes in legislation or regulation

A change in the regulatory model would require varying degrees of changes in legislation or regulations. New laws or regulations may be needed to:

(1) authorize the creation of a new entity (such as an IGO);

(2) transfer oversight functions from the PUC to a new entity – e.g., transfer responsibility in monitoring of reliability to HERA;

(3) authorize the transfer of asset ownership – e.g., transfer the infrastructure needed for system planning and dispatch from utilities to an IGO); and

(4) define new ratemaking paradigms – e.g., totex approach, indexing, and building blocks approach.

If current legislation and regulations are already in place, the regulatory model would score high in this criterion.

3.2.6.2 Minimize additional legal groundwork

The timeframe for the implementation of the necessary changes also differs based on the level of support from stakeholders. It is unlikely that the legislature or the PUC would authorize major changes without eliciting feedback from stakeholders. Some of the steps required in implementing new regulatory models are more likely to face pushback from stakeholders than others. This pushback may be expressed in regulatory proceedings or even as legal challenges in the courts. Regulatory models that require extensive groundwork are more likely to face problems or delays. The Project Team ranked the regulatory models based on the expected length of legislative and regulatory processes that are required in operationalizing the model.

3.3 Weights used for each criterion

The assignment of weights depends on the relevance of the criterion to the goals of the DBEDT Study, the implication for achieving other criteria, and the value of the criterion according to stakeholders. More specifically, the rationale for assigning higher weights to some criteria are discussed below:

- **meet State energy goals (10%):** Hawaii's 100% RPS by 2045 is an ambitious goal and of great significance to the stakeholders. This is particularly evident from the Project Team's discussions with stakeholders and their commitment towards this goal. The RPS target seeks to accelerate the energy transformation in Hawaii's electricity industry. It is also a key driver of this study primarily because there is urgency regarding the role of the State's utilities in helping achieve this goal. The high weight for this category reflects the economic and environmental underpinnings of this goal – underpinnings and considerations that are unique to Hawaii.

- **maximize consumer cost savings (10%):** The ranking emphasizes the importance of lowering energy costs because Hawaii has the highest electricity rates in the United States. Moreover, stakeholders stressed the importance of this metric in their feedback. This factor is also relevant for PUC regulatory decision-making toward any potential transition in utility ownership.[16]

- **align stakeholder interests (10%):** Aligning utility interests with the concerns of ratepayers and other industry participants is one of the most critical factors driving the study of alternative regulatory models. Imposing top-down policies and regulations to address conflicts of interest can also help achieve the necessary outcomes, but a regulatory model that aligns utility incentives with community benefits is ultimately more

[16] See Appendix A, Subsection A on "Ratepayer Benefits," Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket)*, available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

sustainable. Such an approach can also stimulate further innovation in the industry by promoting new partnerships and attracting the participation of new players in the industry.

- **provide utility the ability to earn a fair rate of return (10%):** This category was also given the same higher weight as the previous criteria because it compares the effects of regulatory models on the utilities' ability to raise capital. Hawaii's electricity sector requires a significant amount of investments in modernizing its infrastructure to achieve the State's energy goals, irrespective of the regulatory model chosen by policymakers. The HECO Companies' Power Supply Improvement Plan estimates the necessary investments at over $13 billion in nominal dollars between now and 2045 across the three utilities.[17] The actual amount may vary somewhat depending on regulatory model but will likely be comparable. The magnitude of investments required necessitates a comparison of the impact of each model on the utilities' costs in raising or forming capital. The financial health of utilities is not only important to utility shareholders, but also to current and prospective investors in Hawaii's power sector. A financially stable and creditworthy utility helps to lower costs for IPPs from reduced off-taker risk. It also encourages energy or software companies to develop partnerships with the utility for investments or to provide grid services, similar to what is envisioned in New York.

- **lower costs from transition and operations (10%):** High implementation or transition costs can make a viable regulatory model less palatable politically even if it delivers higher benefits to ratepayers and the community over time. The costs of transition are also felt more acutely because they are concrete, current, and often constitute larger-ticket items such as consultants' fees or infrastructure costs. In contrast, the expected future benefits of a new regulatory model accrue gradually over time and have an element of uncertainty in them. Stakeholders' support for a regulatory model can quickly erode if the transition is lengthy and expensive because these costs are often felt by or passed on to ratepayers.

- **maintain stable rates (10%):** Like consumer cost savings, the ranking emphasizes lower rate volatility because of widespread support from stakeholders for including this metric. The status quo regulatory regime provides consumers with reasonably stable rates. Changes in the regulatory model would create transition costs and further uncertainty down the line regarding costs that can eventually be passed on to ratepayers. Therefore, it is essential to consider the mechanisms that each regulatory model carries so that consumers may be insulated from fluctuations in costs.

---

[17] Hawaiian Electric Companies. *PSIPs Update Report, Book 1.* December 23, 2016. Page 5-5 to 5-27.

Figure 4. The weighting of major and minor categories

Major Category	Minor Category	Weight - Minor	Weight - Major
Support State policy goals	Meet State energy goals	10.0%	40%
	Maximize consumer cost savings	10.0%	
	Enable a competitive distribution system	5.0%	
	Address conflicts of interest	5.0%	
	Align stakeholder interests	10.0%	
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	15%
	Add opportunities to monetize new revenue streams	5.0%	
Minimize implementation costs	Lower costs from transition and operations	10.0%	15%
	Reduce regulatory oversight requirements	5.0%	
Maintain stable rates	Lower risk of rate volatility	10.0%	10%
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	10%
	Meet quality of service standards	2.5%	
	Ensure adequate staffing with required expertise	2.5%	
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	10%
	Minimize additional legal groundwork	5.0%	

3.4 Scoring mechanism

A score of 1, 2, or 3 to each of the groups was provided where 1 indicates a “poor” score, 2 indicates a “neutral” score, and 3 indicates a “positive” score. The scores are based on the results of the analyses discussed in Section 3.2.

Nevertheless, the Project Team acknowledges that each model’s performance in some criteria may be subject to variability that is outside the scope of the regulatory model but informs its transition or context. Such variations could arise due to the timing, combinations, or sequence of changes implemented. In cases where it is both realistic and appropriate, the Project Team has clearly outlined all accompanying assumptions for its scoring. In cases with significant variability and plausible leeway over these factors, the Project Team typically defaults to a "neutral" score to not unduly punish or promote any model unfairly.

4 Recommended regulatory models in Honolulu, Hawaii, and Maui Counties

4.1 Recommended models

The Project Team's analysis identified the top three regulatory models that will be further evaluated in Tasks 2.3 to 2.5. These models, in order of ranking, are 1) Hybrid model, 2) Outcomes-based PBR model, and 3) Conventional PBR with Light HERA model. The detailed scores for each model and the results of the ranking analysis are illustrated in Figure 5. It is important to note that the scoring and ranking discussed in the prior section, while transparently laid out, are to a certain extent subjective. The report acknowledges this by reviewing the 3 most promising regulatory models to provide greater insight on potential alternatives.

The highest-ranking regulatory model is a **Hybrid model** that combines Outcomes-based PBR with a DSPP and an IGO. This Hybrid model scored similarly as the Outcomes-based PBR model in some criteria but was considered more favorable in terms of its ability to facilitate the achievement of State energy goals. The IGO helps to address conflicts of interest and ensure impartiality in interconnection and reliability analyses while the DSPP component supports a transition to a competitive distribution system. Although the transition costs and the likelihood of legal challenges for this model are higher (hence, it scored less favorably than the standalone model in this respect), a staggered implementation of the different components as described in Task 2.2.1 could both lower costs and smoothen the transition. Once implemented, the DSPP and IGO components also would reduce the administrative burden of PBR regime (i.e., by reducing the set of PIMs). In summary, the Hybrid model does not only score high in the specified criteria but also meets the PUC's goals in terms of having mechanisms that result in:[18]

1) greater cost control and reduced rate volatility;
2) efficient investment and allocation of resources regardless of classification as capital or operating expenses,
3) fair distribution of risks between utilities and customers; and
4) fulfillment of State policy goals.

The analysis also shows that the **Outcomes-based PBR** model is well-suited to the State of Hawaii context even as a standalone model. An expanded set of PIMs and a longer regulatory term offers greater flexibility and benefits compared to the other PBR models. However, this model of PBR has not been implemented as widely as Conventional PBR nor is it as familiar to Hawaii's stakeholders as the Light PBR. Consequently, the design and implementation of an Outcomes-

[18] Public Utilities Commission. *Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation*. Docket No. 2018-0088. April 18, 2018.

based PBR would involve more data collection, analyses, and monitoring requirements, likely leading to higher costs.

A combination of the **Conventional PBR with Light HERA** was also ranked favorably in the Project Team's review. It did not score as highly as the two Outcomes-Based PBR models in the first major category (support for State policy goals). However, the scoring indicates that this model would be useful in keeping rates stable. It also scores well across the board in the other major and minor categories.

The following subsections provide a detailed discussion of the rationale for the scores of each of the regulatory model based on the major and minor criteria.

Figure 5. Conclusions of the ranking analyses – Honolulu, Hawaii, and Maui Counties

Major Category	Minor Category	Weight	HERA model	IGO	DSPP	PBR			Conventional PBR + Light HERA	Outcomes-based PBR + DSPP + IGO
						Light	Conventional	Outcomes-based		
Support State policy goals	Meet State energy goals	10.0%	3	3	3	3	3	3	3	3
	Maximize consumer cost savings	10.0%	2	3	1	2	3	3	3	3
	Enable a competitive distribution system	5.0%	1	3	3	1	1	2	1	3
	Address conflicts of interest	5.0%	2	3	2	1	1	2	2	3
	Align stakeholder interests	10.0%	2	2	2	2	3	3	3	3
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	2	1	2	2	2	2	2	2
	Add opportunities to monetize new revenue streams	5.0%	1	1	3	2	2	3	2	3
Minimize implementation costs	Lower costs from transition and operations	10.0%	2	1	1	3	2	1	2	1
	Reduce regulatory oversight requirements	5.0%	3	2	1	2	1	1	1	1
Maintain stable rates	Lower risk of rate volatility	10.0%	2	1	1	2	3	2	3	2
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	3	3	2	3	3	3	3	3
	Meet quality of service standards	2.5%	3	2	2	3	3	3	3	3
	Ensure adequate staffing with required expertise	2.5%	2	1	1	3	2	2	2	1
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	3	1	1	3	2	2	2	1
	Minimize additional legal groundwork	5.0%	2	1	1	2	2	1	2	1
Summary of Major Categories	**Support State policy goals**	**40.0%**	**0.85**	**1.10**	**0.85**	**0.80**	**1.00**	**1.10**	**1.05**	**1.20**
	Ensure utility's financial health	**15.0%**	**0.25**	**0.15**	**0.35**	**0.30**	**0.30**	**0.35**	**0.30**	**0.35**
	Minimize implementation costs	**15.0%**	**0.35**	**0.20**	**0.15**	**0.40**	**0.25**	**0.15**	**0.25**	**0.15**
	Maintain stable rates	**10.0%**	**0.20**	**0.10**	**0.10**	**0.20**	**0.30**	**0.20**	**0.30**	**0.20**
	Strengthen utility's performance	**10.0%**	**0.28**	**0.23**	**0.18**	**0.30**	**0.28**	**0.28**	**0.28**	**0.25**
	Ensure legal viability	**10.0%**	**0.50**	**0.20**	**0.20**	**0.50**	**0.40**	**0.30**	**0.40**	**0.20**
Overall Score			**0.53**	**0.55**	**0.46**	**0.53**	**0.58**	**0.59**	**0.60**	**0.62**
Rank			**6**	**5**	**8**	**7**	**4**	**3**	**2**	**1**

Note:

Scoring System

Good	3
Neutral	2
Poor	1

* by default, all entries are ranked as Neutral, with Good or Poor scores assigned only with justification.

Ranking System

1 – Most favorable model and 8 - Least favorable model

4.2 Scoring rationale

The Project Team provides additional description below of the positive/neutral/poor scoring criteria and rationale for scoring of the different regulatory models by each minor category.

4.2.1 Support State policy goals

For the State's energy goals, the Project Team's analysis concludes that all the models would be able to facilitate the achievement of the RPS requirement, provided that certain conditions and assumptions, such as sound implementation and regulation, are met. However, the models differ in how cost effective they are for consumers and how closely they align utility interests with those of stakeholders.

- **Ability to meet State energy goals**

Ranking	Description	Scoring
Positive	Expected to achieve target RPS by 2045	• All regulatory models
Neutral	Business as usual	• None
Poor	Unlikely to achieve target RPS by 2045	• None

All models ranked positively because they are expected to facilitate the achievement of the target RPS.

- **Maximize consumer cost savings**

Ranking	Description	Scoring
Positive	Electricity bills expected to decrease	• IGO, • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Business as usual	• HERA model • Light HERA
Poor	Electricity bills expected to increase due to high costs of transition	• DSPP

The IGO, Conventional PBR, Outcomes-based PBR, DSPP, and the two hybrid models are most likely to lower costs for consumers over time and therefore ranked positively in this category. The IGO model helps to reduce the costs of energy for consumers through greater competition and closer integration of DERs with the bulk power system. The DSPP model may require high transition costs but could offer cost savings in the long run by fostering more active distribution markets. The two Conventional PBR models control costs to ratepayers through revenue caps on utilities. The Outcomes-based PBR model lowers costs through specific performance targets; in the hybrid model, the incentives are magnified by the IGO. The HERA model would likely result in similar energy costs as the status quo and is thus given a neutral score.

- **Enable a competitive distribution system**

Ranking	Description	Scoring
Positive	Facilitates a transition to distribution-level markets	• IGO • DSPP • Hybrid
Neutral	Greater connection of DERs and design of suitable outcomes or incentives	• Outcomes-based PBR
Poor	No movement towards distribution-level transactions	• HERA model • Light PBR • Conventional PBR • Conventional PBR with Light HERA

Distribution-level markets are only expected to develop under IGO and DSPP models in all four counties. Hence, these models were ranked positively. In the HECO Companies' territory, this includes the hybrid model. None of the other models have any specific mechanism that could facilitate this development although the Outcomes-based PBR model could incorporate specifically targeted outputs and incentives for DER interconnection or distribution market activity/volume. Therefore, the Outcomes-based PBR model scored neutral while the others were ranked poorly.

- **Address conflicts of interest**

Ranking	Description	Scoring
Positive	Effectively separates resource planning, grid operation, and asset ownership	• IGO • Hybrid
Neutral	Some separation of functions	• HERA model • DSPP • Outcomes-based PBR • Conventional PBR with Light HERA
Poor	Same entity is responsible for the majority of grid functions	• Light PBR • Conventional PBR

For the three counties with vertically-integrated IOUs, the two models with an IGO entity can separate the planning and operations of the grid functions. An IGO would oversee resource planning and dispatch, therefore, breaking the potential for utility bias in its planning and dispatch functions. Thus, the IGO and the Hybrid models received a positive score in this category. Light PBR and Conventional PBR models achieved the least amount of separation of planning and operation and received a poor score. Outcomes-based PBR is more effective in leveling the playing field through expanded PIMs and therefore received a neutral rating.

- **Align stakeholder interests**

Ranking	Description	Scoring
Positive	Interests align	• Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Interests are somewhat aligned	• HERA model • IGO • DSPP • Light PBR
Poor	Interests clash	• None

The different variants of PBR models include PIMs and ESMs that help align the interests of utilities and stakeholders in the HECO Companies' territories. Therefore, the PBR models were ranked as positive. The other models were given a neutral score since they would help to partially improve the alignment of the stakeholder interests.

4.2.2 Ensure utility's financial health

The net impact on utility finances is positive for DSPP and PBR models including hybrids. The business and regulatory risks increase under these models because of greater uncertainty about their implementation (especially in the case of DSPP), the potential for unforeseen costs, and risk of financial penalties in the case of the PBR models. However, these risks are offset by the fact that utilities do have the ability to expand their revenue streams.

- **Provide utility the ability to earn a fair rate of return**

Ranking	Description	Scoring
Positive	Lowest levels of risks for utility revenues	• None
Neutral	Some downside risk balanced with upside potential	• HERA model • DSPP • Light PBR • Outcomes-based PBR • Hybrid • Conventional PBR • Conventional PBR with Light HERA

Poor	High risk with little upside	• IGO

All the regulatory models under consideration are likely to increase risks relative to the status quo and therefore result in higher costs of capital for the HECO Companies. The IGO model represents the highest risk for current investors in Hawaii's utilities and therefore received a score of 1 (or poor). For instance, under the IGO model, utilities lose control over long-term resource planning and dispatch. This creates the potential for stranded utility generation assets, particularly for the old and inefficient plants. The other models were given a neutral rank.

- **Bring opportunities to monetize new revenue streams**

Ranking	Description	Scoring
Positive	New revenue streams available to utilities	• DSPP • Outcomes-based PBR • Hybrid
Neutral	Restricted possibility for additional revenue	• Light PBR • Conventional PBR • Conventional PBR with Light HERA
Poor	No additional revenue opportunities	• HERA model • IGO

DSPP and the PBR models (standalone and hybrid) offer the IOUs an opportunity to expand their earnings and thus provided with a positive rank under this criterion. The DSPP model includes platform-service revenues for the utility, through which they could generate fee revenues from third-party service providers. The PBR model comprises extensive performance incentives, enabling utilities to increase their returns by surpassing the targets set. The HERA and IGO models do not include mechanisms for incremental earnings and therefore got a poor score.

4.2.3 Minimize implementation costs

The HERA and Light PBR models entail a limited set of changes relative to the status quo, thus, have the lowest costs of transition for the three IOUs. They are most straightforward to implement, familiar to current stakeholders and do not require a regulatory overhaul.

- **Lower costs from transition and operations**

Ranking	Description	Scoring
Positive	Low costs of transition	• Light PBR
Neutral	Some costs of transition	• HERA model • Conventional PBR • Conventional PBR with Light HERA

Poor	Implementation of a new model likely to entail an expensive and lengthy process	• IGO • DSPP • Outcomes-based PBR • Hybrid

IGO, DSPP, and the two Outcomes-based PBR models in the HECO Companies' territories rank poorly in this category as they involve high costs of transition for different reasons. IGO requires transferring system planning and dispatch infrastructure from the current utilities to the new entity; the needed support involves both hardware and software. Moreover, there may also be a transfer of personnel. As mentioned previously, costs of transition for the DSPP model are not fully known and are likely to be high. Likewise, implementation of the Outcomes-based PBR models would likely entail extensive studies that can help define the desired outcomes clearly with their corresponding performance targets and financial incentives/penalties. Furthermore, these models must also address consumer concerns about the complexity of the structure.

On the other hand, implementing the Light PBR model would involve predictable and mostly understood costs and processes. The transition would also be relatively simple for the HERA model. Therefore, these two regulatory models ranked positively in this criterion.

- **Reduce regulatory oversight requirements**

Ranking	Description	Scoring
Positive	PUC has the required expertise and personnel	• HERA model
Neutral	Small changes in PUC oversight	• IGO • Light PBR
Poor	Expanded breadth and complexity of issues overseen by the PUC	• DSPP • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid

The HERA model ranked positively in this criterion because it requires the smallest changes in the PUC's scope of responsibilities. Even though there is a new entity created, its independence helps to lessen the adversarial nature of PUC oversight.

DSPP and the standalone and hybrid variants of the PBR models (except the Light PBR model) ranked poorly as they would significantly increase the responsibilities of the PUC. Due to the inherent complexity of the DSPP model, the PUC must directly oversee its design and implementation. The lack of examples in other jurisdictions only imposes more burden on the PUC. Likewise, the PBR models also demand a more active role of the PUC in defining outcomes, setting targets, and ensuring compliance. The other models

(IGO and Light PBR) were ranked neutral as the regulatory oversight of the PUC would remain relatively the same.

4.2.4 Provide stable rates

Ranking	Description	Scoring
Positive	Includes stronger mechanisms to stabilize rates	• Conventional PBR • Conventional PBR with Light HERA
Neutral	Some rate stability – status quo	• HERA model • Light PBR • Outcomes-based PBR • Hybrid
Poor	Ratepayers are likely to face fluctuating prices	• IGO • DSPP

Conventional PBR models—both standalone and hybrid—have the most stable rates because they feature fixed regulatory period and forecasted rates. Thus, they ranked positively in this criterion.

Although the Outcomes-based PBR models also have a fixed regulatory period and set rates, they have a longer regulatory term of five years and feature a more comprehensive set of PIMs that could impact the rates paid by consumers for the next regulatory period. Therefore, there is a risk that rates would fluctuate in the subsequent regulatory period. As such, the Outcomes-Based PBR received a neutral score.

The IGO and DSPP models introduce more significant exposure to market dynamics as well as unknown elements of costs, all of which suggest a tendency toward greater rate volatility. Thus, they were given a poor score.

4.2.5 Strengthen utility's performance

- **Provide an adequate and reliable electricity supply**

Ranking	Description	Scoring
Positive	Expected to ensure reliable electric service	• HERA model • IGO • Light PBR • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Generally reliable with some risk of disruptions	• DSPP
Poor	Unlikely to provide reliability	• None

A distribution-level market platform that is separate from bulk electricity has some risk of disruptions especially because a full-fledged implementation does not exist. Therefore, the DSPP model scored neutral in this criterion.

When DSPP is combined with Outcomes-based PBR and IGO under the Hybrid model, the incentives under PBR and the IGO's mandates would ensure reliability. Therefore, the Hybrid model scored positively.

All other models are expected to provide reliable electric service and thus, given a positive score.

- **Meet quality of service standards**

Ranking	Description	Scoring
Positive	Prompt and responsive customer service	• HERA model • Light PBR • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA • Hybrid
Neutral	Business as usual	• IGO • DSPP
Poor	Low priority is given to customer service	• None

All models except the IGO and DSPP models are expected to perform better in this criterion and thus scored positively. The IGO and DSPP models are less likely to result in better quality customer service because utilities in these models have less control over the electricity system. Although the IGO could provide its own customer service and would improve interconnection, the utility is expected to remain the customer-facing entity in this structure. As a result, customers may be somewhat unsatisfied if the utilities are unable to resolve or answer all of their issues. For this reason, these models were scored neutral under this criterion.

- **Ensure adequate staffing with the required expertise**

Ranking	Description	Scoring
Positive	Utilities and other entities have the required expertise and personnel	• Light PBR
Neutral	Small changes in staffing requirements	• HERA model • Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA

Poor	Hiring of lots of expert personnel	• IGO • DSPP • Hybrid

Utilities could likely meet their operational requirements with their current personnel under the Light PBR model. This model involves expansion of the PIMs, which current staff can implement. Hence, the Light PBR ranked positively under this category.

On the other hand, IGO, DSPP, and the Hybrid models would expand hiring needs and scored poorly in this criterion The IGO entity requires staff with the necessary expertise so that it can perform its functions; not all of its hiring needs can be met with a transfer of personnel from the current utilities. Greater technological expertise is also needed to implement the complex transactions and software platforms necessary for a DSPP model.

4.2.6 Ensure legal viability

- **Limited required changes in legislation or regulation**

Ranking	Description	Scoring
Positive	Requires no (or minor) regulatory action and no legislative action	• Light PBR • HERA model
Neutral	Requires regulatory action but no legislative action	• Conventional PBR • Outcomes-based PBR • Conventional PBR with Light HERA
Poor	Requires both regulatory and legislative action	• IGO • DSPP • Hybrid

The Light PBR model and HERA model could be implemented in the HECO Companies' territories through a minor regulatory proceeding to expand the PIMs and add rewards and penalties and to list the responsibilities of the HERA, respectively. It could be implemented with only minor regulatory changes and was thus ranked positively.

In contrast, the models involving IGO and DSPP (including the combined hybrid model) ranked poorly in this category as they require accompanying legislative and regulatory action that would authorize the creation of the new entities and define the industry structure.

- **Minimize additional legal groundwork**

Ranking	Description	Scoring
Positive	Little risk of legal challenges from stakeholders	• None
Neutral	Moderate risk of legal challenges from stakeholders	• HERA model • Light PBR

		• Conventional PBR • Conventional PBR with Light HERA
Poor	Major risk of legal challenges from stakeholders	• IGO • DSPP • Outcomes-based PBR • Hybrid

All regulatory models under consideration for the three IOU counties entail detailed work—including with legal teams that would help define the new regulatory structures—and therefore carry some risk of legal challenges from stakeholders.

The risk is higher for IGO, DSPP, Outcomes-based PBR, and hybrid model that combines all three. Utilities are likely to resist a transition to an IGO or DSPP structure because it is most disruptive to their vertically-integrated operations. Because of this, these models ranked poorly under this criterion.

5 Recommended regulatory models in Kauai County

5.1 Recommended models

The Project Team also conducted a similar analysis separately for Kauai County, owing to its different ownership structure (co-op) and preferences indicated by its stakeholders. Instead of the hybrid models evaluated for the HECO Companies, the Project Team included a Lighter PUC Regulation model in addition to the four regulatory models. The top three regulatory models for Kauai County, in order of ranking, excluding the Status Quo, are 1) HERA model, 2) IGO, and 3) Lighter PUC Regulation. The detailed scores for each model and the results of the ranking analysis are shown in Figure 6. As mentioned previously, it is important to note that the scoring and ranking are subjective to a certain extent. Therefore, the report acknowledges this by casting a wider net and reviewing the 3 most promising regulatory models for further analyses.

The **HERA model** ranked the highest among the regulatory models due to its potential to support the State policies, strengthen the utility's performance, and legal viability. Under this model, KIUC would maintain its current structure as a co-op. Its member-owned structure can intrinsically align interests between ratepayers (or the interests of the majority) and the utility. It has access to subsidized debt that allows it to provide grid services to ratepayers while controlling costs.

Compared to the HERA model, the **IGO model** would incur significant transition costs. It also increases the likelihood of rate volatility and would require substantial legal work to implement. However, it is more likely to result in increased competition at the distribution level.

Modifying the PUC's current regulatory oversight over KIUC to a "lighter-touch" approach—the **Lighter PUC Regulation model**—can deliver even more savings to the customer-members. This model decreases the regulatory costs for KIUC by granting it greater autonomy. However, the Project Team's analysis finds that removing direct PUC oversight may create risks in the implementation of State goals as enacted by the Governor and legislature. Furthermore, this model also scores lower in terms of legal feasibility because it does not have sufficient safeguards against the management of conflict of interest, short-term decision-making (that have negative impacts in the long term) by the KIUC Board, and disputes between KIUC leadership and a minority of its members.

The following subsections provide a detailed discussion of the rationale for the scores of each of the regulatory models based on the major and minor criteria.

Figure 6. Conclusions of the ranking analyses – Kauai County

Major Category	Minor Category	Weight	Status Quo with HERA	IGO	DSPP	Lighter PUC Regulation
Support State policy goals	Meet State energy goals	10.0%	3	3	3	1
	Maximize consumer cost savings	10.0%	2	3	1	3
	Enable a competitive distribution system	5.0%	1	3	3	1
	Address conflicts of interest	5.0%	3	3	3	2
	Align stakeholder interests	10.0%	3	2	2	2
Ensure utility's financial health	Provide utility the ability to earn a fair rate of return	10.0%	2	2	1	3
	Add opportunities to monetize new revenue streams	5.0%	1	2	3	1
Minimize implementation costs	Lower costs from transition and operations	10.0%	2	1	1	3
	Reduce regulatory oversight requirements	5.0%	1	1	1	3
Maintain stable rates	Lower risk of rate volatility	10.0%	2	1	1	2
Strengthen utility's performance	Provide an adequate and reliable electricity supply	5.0%	3	3	2	3
	Meet quality of service standards	2.5%	3	2	2	2
	Ensure adequate staffing with required expertise	2.5%	2	1	1	3
Ensure legal viability	Limit required changes in legislation or regulation	5.0%	3	1	1	2
	Minimize additional legal groundwork	5.0%	2	1	1	2
Summary of Major Categories	**Support State policy goals**	**40.0%**	**1.00**	**1.10**	**0.90**	**0.75**
	Ensure utility's financial health	**15.0%**	**0.25**	**0.30**	**0.25**	**0.35**
	Minimize implementation costs	**15.0%**	**0.25**	**0.15**	**0.15**	**0.45**
	Maintain stable rates	**10.0%**	**0.20**	**0.10**	**0.10**	**0.20**
	Strengthen utility's performance	**10.0%**	**0.28**	**0.23**	**0.18**	**0.28**
	Ensure legal viability	**10.0%**	**0.50**	**0.20**	**0.20**	**0.40**
Overall Score			**0.57**	**0.56**	**0.47**	**0.51**
Rank			**1**	**2**	**4**	**3**

Note:

Scoring System

Good	3
Neutral	2
Poor	1

* by default, all entries are ranked as Neutral, with Good or Poor scores assigned only with justification.

Ranking System

1 – Most favorable model and 4 - Least favorable model

5.2 Scoring rationale

5.2.1 Support State policy goals

- **Ability to meet State energy goals**

Ranking	Description	Scoring
Positive	Expected to achieve target RPS by 2045	• HERA model • IGO • DSPP
Neutral	Business as usual	• None
Poor	Unlikely to achieve target RPS by 2045	• Lighter PUC Regulation

All models, except for the Lighter PUC Regulation model, are expected to facilitate the achievement of the target RPS. The Lighter PUC Regulation model was scored as poor because the PUC and other State entities has less direct control over the utility in implementing State policies and in directing the utility toward targets associated with State goals.

- **Maximize consumer cost savings**

Ranking	Description	Scoring
Positive	Electricity bills expected to decrease	• IGO • Lighter PUC Regulation
Neutral	Business as usual	• HERA model
Poor	Electricity bills expected to increase	• DSPP

- The IGO and Lighter PUC Regulation models all result in lower costs to consumers and as such scored positively in this category. The IGO model can pass on the savings generated from increased competition. Meanwhile, the Lighter PUC Regulation model also lowers the expenses of regulatory proceedings that consumers have to bear ultimately. The HERA model is ranked neutral because any additional costs associated with the HERA entity is expected to be minimal relative to overall utility costs. The DSPP model is ranked poor due to high implementation costs.

- **Enable a competitive distribution system**

Ranking	Description	Scoring
Positive	Facilitates a transition to distribution-level markets	• IGO • DSPP
Neutral	Greater connection of DERs	• None
Poor	No movement towards distribution-level transactions	• HERA model • Lighter PUC Regulation

Under IGO and DSPP models, distribution-level markets are expected to be developed. Thus, these models ranked positively. The other models would be less able to foster a competitive distribution system and thus scored poorly.

- **Address conflicts of interest**

Ranking	Description	Scoring
Positive	Effectively separates resource planning, grid operation, and asset ownership	• HERA model • IGO • DSPP
Neutral	Some separation of functions	• Lighter PUC Regulation
Poor	Same entity is responsible for the majority of grid functions	• None

HERA and IGO models scored positively in addressing conflicts of interests as these models include an independent entity (such as the PUC, IGO, and HERA) that ensures fairness in interconnection or dispatch. The IGO model also separates system planning, resource planning, system operations, and dispatch functions from the utility. The DSPP model helps to resolve conflicts by altering the utility's business model and ensuring it can benefit from greater participation of customers and third parties in distribution markets. The Lighter PUC Regulation model is given a neutral score because it makes PUC oversight more difficult, for example, in cases when there is a need to settle disputes and grievances in the co-op. It also does not introduce any separations in utility functions from the current vertically-integrated structure.

- **Align stakeholder interests**

Ranking	Description	Scoring
Positive	Interests align	• HERA model
Neutral	No relation between utility and ratepayer interests	• IGO • DSPP • Lighter PUC Regulation
Poor	Interests clash	• None

The HERA model ranked positively in this category because of the presence of a regulatory body that provides oversight of the regulated entities to ensure that the customers are served fairly and efficiently and ensures that utilities are financially viable. The other models ranked neutral.

5.2.2 Ensure utility's financial health

- **Provide utility the ability to earn a fair rate of return**

Ranking	Description	Scoring

Positive	Lowest levels of risks for utility revenues	• Lighter PUC Regulation
Neutral	Some downside risk balanced with upside potential	• HERA model • IGO
Poor	High risk with little upside	• DSPP

The financial aspects are different for KIUC because of its co-op structure. It raises equity capital from its members in the form of patronage capital, which it retires periodically by crediting the amount back to its members. KIUC's financial health depends on its ability to control expenditures, which can be achieved through the Lighter PUC Regulation model, which was therefore ranked positively. The DSPP model is likely to add the greatest strain on KIUC finances because of unpredictable infrastructure needs. Even though it could lower costs in the long run, the likely transition costs and risks are at odds with the cost minimization approach emphasized by KIUC and its lenders. The DSPP model thus scored poorly in this criterion. On the other hand, the IGO model is ranked as neutral despite the likelihood of significant transition costs because IGO operations are well understood and thus carry low risks.

- **Bring opportunities to monetize new revenue streams**

Ranking	Description	Scoring
Positive	New revenue streams available to utilities	• DSPP
Neutral	Restricted possibility for additional revenue	• IGO
Poor	No additional revenue opportunities	• HERA model • Lighter PUC Regulation

On Kauai County, only the DSPP model can definitely support incremental revenue generation for the utility from distribution market activity and platform services. A more seamless integration of DERs and bulk power in one system under the IGO model could create potential earning opportunities for the utility as the owner of all wire assets. However, such revenues would likely be defined by the IGO and would also depend on the IGO's market rules. Therefore, this model was ranked neutral. HERA and IGO models are ranked poorly as they do not provide additional revenue opportunities for the co-op. The Lighter PUC Regulation would reduce regulatory expenses but would not change utility revenues. The HERA model simply adds a separate oversight body, which could add some costs to the utility but would not alter its revenue streams.

5.2.3 Minimize implementation costs

- **Lower costs from transition and operations**

Ranking	Description	Scoring
Positive	Low costs of transition	• Lighter PUC Regulation

Neutral	Some costs of transition	• HERA model
Poor	Implementation of a new model likely to entail an expensive and lengthy process	• IGO • DSPP

All regulatory models except the Status Quo involve some transition costs. More specifically, the IGO and DSPP models require significant investments in implementation and thus ranked poorly under this category.

The Lighter PUC Regulation model also requires some legislative enactments, but this is offset by a decrease in its ongoing regulatory expenses. Therefore, the Lighter PUC Regulation model received a positive score.

- **Reduce regulatory oversight requirements**

Ranking	Description	Scoring
Positive	PUC has the required expertise and personnel	• Lighter PUC Regulation
Neutral	Small changes in PUC oversight	• None
Poor	Expanded breadth and complexity of issues overseen by the PUC	• DSPP • HERA model • IGO

As the name suggests, only the Lighter PUC Regulation model reduces regulatory oversight of KIUC and hence, it received a positive score. Regulatory models such as HERA, IGO, and DSPP require additional regulatory oversight and thus ranked poorly.

5.2.4 Maintain stable rates

Ranking	Description	Scoring
Positive	Includes stronger mechanisms to stabilize rates	• None
Neutral	Some rate stability – status quo	• HERA model • Lighter PUC Regulation
Poor	Ratepayers are likely to face fluctuating prices	• IGO • DSPP

The IGO and DSPP models are ranked poorly because they are expected to increase rate volatility in Kauai County. Both models entail significant transition costs, which would likely be reflected at least partially in electricity rates. Even after the models are established, rates would be more susceptible to competitive forces, market rules established by the IGO, or future growth in platform-based services that the utility could monetize under the DSPP model. Utility operations under the HERA and Lighter PUC Regulation models are unlikely to change significantly and therefore not likely to impact rate volatility. The two models thus scored neutral.

5.2.5 Strengthen utility's performance

- **Provide an adequate and reliable electricity supply**

Ranking	Description	Scoring
Positive	Expected to ensure reliable electric service	• HERA model • IGO • Lighter PUC Regulation
Neutral	Generally reliable with some risk of disruptions	• DSPP
Poor	Unlikely to provide reliability	• None

The DSPP model ranked neutral as it carries some risk of interruptions in electric service. A distribution-level market platform that is separate from bulk electricity carries some risk of disruptions especially because a full-fledged implementation does not exist. All other models are expected to provide reliable electric service and thus, scored positively.

- **Meet quality of service standards**

Ranking	Description	Scoring
Positive	Prompt and responsive customer service	• HERA model
Neutral	Business as usual	• IGO • DSPP • Lighter PUC Regulation
Poor	Low priority is given to customer service	• None

The HERA model is ranked positively because of the presence of an additional oversight body. The IGO and DSPP models are less likely to result in quality customer service because the co-op has less control over some components of the electricity system. Furthermore, third parties may also provide some customer and grid services under the DSPP model. As a result, these two models garnered a neutral score.

The Lighter PUC Regulation model for KIUC also carries some risk when it comes to customer service—for example, there is no other regulatory body other than the KIUC Board ensuring that services are provided reliably and safely. Therefore, this model ranked neutral due to lack of direct oversight from an entity other than the co-op Board.

- **Ensure adequate staffing with the required expertise**

Ranking	Description	Scoring
Positive	Utilities and other entities have the required expertise and personnel	• Lighter PUC Regulation

Neutral	Small changes in staffing requirements	• HERA model
Poor	The hiring of lots of expert personnel	• IGO • DSPP

The Lighter PUC Regulation model does not impact staffing needs for KIUC and thus received a positive score. The HERA model requires the creation of an independent body but was ranked neutral because it is likely to be a small body and the necessary expertise already exists. On the other hand, DSPP and IGO models require significant expertise and new capabilities and therefore rank poorly in this category.

5.2.6 Ensure legal viability

- **Limited required changes in legislation or regulation**

Ranking	Description	Scoring
Positive	Requires no regulatory or legislative action	• HERA model
Neutral	Requires minor regulatory action but no legislative action	• Lighter PUC Regulation
Poor	Requires both regulatory and legislative action	• IGO • DSPP

Major legislative or regulatory changes are not required for the Status Quo and HERA models in Kauai County, and therefore they received a positive score. On the other hand, the Lighter PUC Regulation model for KIUC requires some legislative changes while the IGO and DSPP models need much more legislative or regulatory change.

- **Minimize additional legal groundwork**

Ranking	Description	Scoring
Positive	Little risk of legal challenges from stakeholders	• None
Neutral	Moderate risk of legal challenges from stakeholders	• HERA model • Lighter PUC Regulation
Poor	Major risk of legal challenges from stakeholders	• IGO • DSPP

The IGO and DSPP models ranked poorly under this category as they require significant legal work in Kauai County. Although there is already a regulation enabling HERA, there is still additional legal groundwork needed to implement it. Accordingly, the HERA model ranked neutral in this regard. The Lighter PUC Regulation model is also ranked neutral since it requires some redrafting of rules and clear guidance on KIUC's obligations and what can trigger "re-regulation" if KIUC fails to meet those obligations.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.2.6 Identification and recommendation for the three most beneficial regulatory models for further consideration.

CONTRACTOR shall identify and recommend three feasible regulatory models for further consideration.

DELIVERABLE FOR TASK 2.2.6. CONTRACTOR shall provide its conclusions and all work to make recommendations on the three most beneficial models for further consideration. The CONTRACTOR compares models to identify the top three models that merit additional analyses. The remaining tasks in TASK 2 shall be conducted for the top three models. CONTRACTOR shall provide a written description of the analysis in MS Word and an MS Excel spreadsheet. CONTRACTOR shall submit deliverable for TASK 2.2.6 to the STATE for approval.

7 Appendix B: List of works consulted

"Division of Consumer Advocacy's Direct Testimonies and Exhibits," Division of Consumer Advocacy, Docket No. 2015-0022, August 10, 2015, https://cca.hawaii.gov/dca/files/2015/08/2015-0022-CA-DT-and-Exhibits-PUBLIC.pdf

Energy Information Administration, State Electricity Profiles, January 17, 2017, available at: https://www.eia.gov/electricity/state/.

Hawaii Public Utilities Commission, *Order No. 33795 (Dismissing Application Without Prejudice and Closing Docket),* available at: https://puc.hawaii.gov/wp-content/uploads/2016/07/FINAL.ORDER_.33795.Docket2015-0022.pdf.

Hawaii Public Utilities Commission, "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, Decision and Order No. 32052, filed on April 28, 2 014, ("Order No. 32052"), available at https://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf.

Hawaii State Energy Office, Hawaii Department of Business, Economic Development, and Tourism, "Energy Policy Directives," March 2017, available at: https://energy.hawaii.gov/wp-content/uploads/2011/08/EnergyPolicy_1pgr_rev-Mar2017.pdf.

The Steps, Costs, Timeline, Legal Changes, and Risks for Establishing the Recommended Regulatory Models

Working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group, a Cadmus Company

January 8, 2019

London Economics International LLC, together with Meister Consultants Group, a Cadmus Company ("the Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State's efforts to achieve its energy goals. As part of this engagement, this working paper provides a discussion of costs, steps, timelines, legal considerations, and risks for the three highest ranked regulatory models from Task 2.2.6: (i) Outcomes-based Performance-based Regulation ("PBR"), (ii) Conventional PBR with Light HERA, and (iii) a Hybrid Model that combines Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Independent Grid Operator ("IGO"). These tasks respectively correspond with Tasks 2.3.1, 2.3.2, and 2.3.3 of the study. To describe the steps and timeline, the Project Team reviewed existing literature on these regulatory models, outlined key tasks involved for each model, and estimated the time necessary for individual steps for establishment and operation. To assess the costs, the Project Team evaluated the costs incurred by utilities in other jurisdictions that previously made such regulatory shifts as those contemplated by this study. For legal considerations, the Project Team researched the legal requirements and legal changes for the establishment, funding, and operation of each regulatory model. Finally, the Project Team describe the likelihood and magnitude of the operational and financial risks faced by both ratepayers and shareholders for each regulatory model.

Table of Contents

717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com
Ryan Cook/Arielle Magliulo
503-467-7107
ryan.cook@cadmusgroup.com

Table of Figures

List of acronyms

AUC	Alberta Utilities Commission
BCA	Benefit Cost Analysis
CA	California
CAISO	California Independent System Operator
CFR	Code of Federal Regulations
COS	Cost of Service
D&O	Decision and Order
DBEDT	Department of Business, Economic Development & Tourism
DER	Distributed Energy Resources
DG	Distributed Generation
DPS	Department of Public Service
DSIP	Distributed System Implementation Plan
DSPP	Distributed System Platform Provider
ECAC	Energy Cost Adjustment Clause
EIS	Environmental Impact Statement
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESM	Earnings Sharing Mechanism
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FR	Federal Register
FY	Fiscal Year
GEMS	Green Energy Market Securitization Program

GW	Gigawatt
GWh	Gigawatt Hour
HAR	Hawaii Administrative Rules
HB	House Bill
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaiian Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
HGIA	Hawaii Green Infrastructure Authority
HI	Hawaii
HRS	Hawaii Revised Statutes
IGO	Independent Grid Operator
IPP	Independent Power Producer
IRP	Integrated Resource Planning
ISO	Independent System Operator
KIUC	Kauai Island Utility Cooperative
kW	Kilowatt
kWh	Kilowatt Hour
LEI	London Economics International
MM	Million
MCG	Meister Consultants Group, a Cadmus Company
MECO	Maui Electric Company
MW	Megawatt
MWh	Megawatt Hour

NERA	National Economic Research Associates, Inc.
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NY	New York
NY REV	New York's Reforming the Energy Vision
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool
NYSRC	New York State Reliability Council
Ofgem	Office of Gas and Electricity Markets
PBR	Performance Based Regulation
PCS	New York Public Service Commission
PIMs	Performance Incentive Mechanisms
PPAC	Purchase Power Adjustment Clause
PSIP	Power Supply Improvement Plan
PSL	Public Service Law
PUC	Public Utilities Commission
PV	Photovoltaics
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RPI-X	Retail Price Index ("RPI") minus energy efficiency savings ("X")
RPS	Renewable Portfolio Standard
RSWG	Reliability Standards Working Group
RTO	Regional Transmission Organization

SAIC	Science Applications International Corporation
SAIDI	System Average Interruption Duration Index
SAIFI	Average Interruption Frequency Index
SB	Senate Bill
T&D	Transmission and Distribution
TIS	Texas Interconnect System
Totex	Total Expenditure
TFP	Total Factor Productivity
TW	Terawatt
TWh	Terawatt Hour
TX	Texas
UK	United Kingdom
US	United States
USC	United States Code

1 Executive summary

In Task 2.2.3 and 2.2.6, the Project Team provided a high-level overview of the legal, technical, and financial feasibility of five regulatory models and ranked them according to those criteria. The three highest ranking models from this analysis were the *Outcomes-based Performance-based Regulation ("PBR")*, *Conventional PBR with Light HERA*, and a *Hybrid Model*. Definitions of each of these regulatory models, as well as the Status Quo, are outlined in each of the "key conclusions" paragraphs below. In this subsequent working paper intended to cover Task 2.3.1, 2.3.2, and 2.3.3, the Project Team analyzes each of these regulatory models with regards to the following topics:

- The steps, timeline, and costs required to change from the current regulatory model and establish the recommended regulatory models;

- Legal steps or regulatory and legislative changes necessary to implement the recommended regulatory models; and

- Financial and operational risks for ratepayers and shareholders. For the risks, the Project Team categorizes such risks in terms of its overall *impact* and *probability* in tiers of low, low-medium, medium, medium-high, and high.

The Status Quo regulatory model is the regulatory model currently in use in Hawaii. It is characterized by use of traditional cost of service ("COS") regulation plus some light performance incentive mechanisms. Under this regulatory model which features a capex approach, the PUC sets rates that permit the utilities to recover the costs they incurred to provide service, plus a return on investment, so long as the costs are considered to be just and reasonable. The key conclusions of the Status Quo regulatory model include the following:

- The Status Quo regulatory model, by definition, requires no *steps*, *costs*, or *legal changes* to be implemented. In effect, the Status Quo regulatory model preserves regulation under a traditional cost of service regulation.

- In terms of potential *risks*, the Status Quo provides a conflict between the interests of ratepayers and utility shareholders. The COS model maximizes shareholder returns by making capital investments and increasing the rate base, which can lead to higher rates for ratepayers. In addition, this model provides no direct financial incentive to achieve state policy objectives. Finally, continued use of this model could lead to nonlinear grid defection by dissatisfied ratepayers, which would have severe repercussions for the utility and its shareholders.

The Outcomes-based PBR regulatory model is characterized as the most comprehensive PBR regime that seeks to incentivize the utility toward beneficial outcomes that can include enhanced customer experience, improved utility performance, achievement of public policy goals, and healthy financial performance. This model uses a totex approach and features an expanded set of Performance Incentive Mechanisms ("PIMs"), an Earning Sharing Mechanism ("ESM"), and a longer (5 years) regulatory period. The key conclusions for the Outcomes-based PBR model include the following:

- The *timeline* of the establishment of an Outcomes-based PBR model should take 21 months to complete to comply with State law requiring implementation of PBR by January 1, 2020, although implementation of this model in the UK took 30 months. Hawaii is expected to be able to achieve a shorter timeline than the UK due to the comparatively smaller size and lower complexity of its regulatory market. The *steps* of this timeline include the decision to design the PBR model and publishing its guiding principles and framework, determining the outputs and price control methodology and engaging with stakeholders, working with the utility companies to develop business plans that are compliant with the new model, and revising non-compliant business plans, and finally setting the price control. Alternatively, it is possible that the PUC could put in place the initial PBR framework and continue the evolution to an Outcomes-based PBR over time, although this analysis focuses on full implementation by the legislative deadline.

- The *costs* of establishing the Outcomes-based PBR model primarily consist of the operational costs of the PUC to complete the amount of work necessary to successfully implement the model. Based on an analysis of jurisdictions that have transitioned from COS to PBR and the Public Utility Commission's ("PUC's") current operating expenses, the Project Team estimates that the cost of implementing Outcomes-based PBR in Hawaii could result in a 10.9% increase in regulatory expense during the implementation period, and that the cost of operating under the PBR model would decrease to amounts similar to the current regulatory expense.

- In terms of *legal changes*, the existing legal framework, including legislation that specifically requires PBR implementation, illustrate that the PUC is authorized to implement and regulate PBR in Hawaii. No changes to the legal framework are necessary to establish the Outcomes-based PBR model.

- In terms of potential *risks*, Outcomes-based PBR carries a medium risk level for most the risk factors considered in this report (regulatory cost, regulatory complexity, rates, profit, incentives, reliability, low DER, and infrastructure inefficiency), primarily due to the uncertainty related to whether the PBR will function as intended. Aside from profits risk, the impact of these risks is generally higher for ratepayers than for shareholders.

The Conventional PBR with Light HERA regulatory model combines two regulatory models. Conventional PBR is characterized by the use of a revenue cap using an indexing formula, a three-year regulatory term, a symmetrical ESM, and slight expansion of PIMs. Light HERA is an entity that would support the PUC in the regulation and oversight of the reliability and accessibility of Hawaii's electricity systems. The key conclusions for the Conventional PBR with Light HERA model include the following:

- The *timeline* for implementing Conventional PBR should take 21 months to complete to comply with State law requiring implementation of PBR by January 1, 2020, although as a point of comparison, a comparable effort in Alberta, Canada, was implemented over the course of 33 months. Hawaii is expected to be able to achieve a shorter timeline than Alberta due to the comparatively smaller size and complexity of its regulatory market. The *steps* of this timeline include the decision to change to PBR, designing the PBR model

717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com
Ryan Cook/Arielle Magliulo
503-467-7107
ryan.cook@cadmusgroup.com

and publishing its guiding principles, framework, and methodology, educating and engaging with stakeholders, working with the utility companies to develop business plans that are compliant with the new model, and finally implementing the Conventional PBR. Alternatively, it is possible that the PUC could put in place the initial framework and continue the evolution to a comprehensive Conventional PBR over time, although this analysis focuses on full implementation by the legislative deadline.

The *timeline* for implementing Light HERA is not contingent upon any deadlines at this time but should take approximately two years to implement, which is the average time of a PUC docket proceeding. The *steps* involved in the PUC docket proceeding are the next steps required to implement HERA, since there is already legislation passed and initial research completed, including a statement by the PUC that the next step is an investigative proceeding.

- The *costs* of establishing Conventional PBR are, like Outcomes-based PBR, essentially the operational costs of the PUC to complete the amount of work necessary to successfully implement the model. Based on an analysis of jurisdictions that have transitioned from COS to PBR and the Public Utility Commission's ("PUC's") current operating expenses, the Project Team estimates that the cost of implementing Conventional PBR in Hawaii could result in a 10.9% increase in regulatory expense, and that the cost of operating under the PBR model would be similar to current regulatory expense.

  The *costs* of implementing and operating the HERA entity are also based on an analysis of another jurisdiction that made a similar transition to develop a HERA-like entity. Using this analysis, we estimate that the HERA transition costs are between $234,000 and $585,000, and the annual operating costs range from $483,000 to $1,208,000.

- In terms of *legal changes*, the existing legal framework, including legislation that specifically requires the implementation of PBR, as well as legislation that explicitly authorizes the creation of HERA, illustrate that the PUC is authorized to implement and regulate the Conventional PBR with Light HERA regulatory model in Hawaii. No changes to the legal framework are necessary to establish the Outcomes-based PBR model.

- In terms of potential *risks,* this model carries similar but less severe risks to Outcomes-based PBR because Conventional PBR is a less complex PBR model than Outcomes-based PBR. In addition, this model can be differentiated by the fact that it carries lower risks for reliability because it is purposed with improving reliability.

The Hybrid regulatory model is characterized by a combination of the Outcomes-based PBR model, a DSPP, and an IGO. As was described above, the Outcomes-based PBR model is the most comprehensive PBR regime that seeks to incentivize the utility toward beneficial outcomes that can include enhanced customer experience. The DSPP regulatory model alters the role of the utilities and causes the utilities to function as DSPPs. In effect, this means that the utilities as DSPPs are the purchasers and aggregator of DER and creates market tariffs and operational systems to enable behind-the-meter resources to monetize products and services. An IGO is an independent entity that manages the dispatch and planning functions on the grid and helps avoid conflicts of interest and ensures impartiality among the parties involved. The key conclusions for the Hybrid model include the following:

- The *timeline* for the hybrid model is staggered to reduce the volatility that would probably result from too many regulatory changes at once. This staggered implementation features a January 1, 2020 implementation of an initial Outcomes-based PBR to comply with state law, implementation of the IGO in 2023, and implementation of DSPP operations beginning in 2028. The *steps* for the Outcomes-based PBR implementation are listed above. The IGO is likely to take approximately 2 years to implement, as was the case in three other jurisdictions that implemented an IGO, and the specific steps are dependent on what method the State wishes to use. The DSPP is likely to take at least 3 years to implement and will likely be conducted through a regulatory proceeding.

- The *costs* to implement the Hybrid are also a combination of the costs to implement and perform each of its component parts. As discussed above, the Outcomes-based PBR model is likely to cause a 10.9% increase in regulatory expense but should return to normal levels following the end of the three-year transition period. For both the IGO and DSPP models, the Project Team notes particular uncertainty for our cost calculations due to more limited examples from which to draw comparisons with. Nevertheless, we estimate that the IGO will be at least $8.0 million in startup costs and annual costs, based on a comparison to similar mainland organizations. The costs for implementing the DSPP are estimated at $51.4 million, spread over a three-year transition period, and a $1.0 million annual operating cost thereafter.

- In terms of *legal* changes, no changes to the legal framework are necessary to establish the Outcomes-based PBR model, as discussed above. For the DSPP model, there is no explicit authority for such an entity under state law, however, its creation should fall under the broad regulatory authority of the PUC. To err on the cautious side and to follow its own precedent of legislating specific PUC responsibilities, the State may want to legislate to explicitly authorize DSPP, although it does not need to. For the IGO model, there is no express legal authority to create an IGO. And while the PUC may be authorized to implement some aspects of it (such as opening an investigative proceeding to learn about IGOs, or using HERA to carry out some functions that the ISO would do), we expect that legislation explicitly authorizing creation of the IGO and regulation of it by the PUC would be necessary to implement this element of the Hybrid model.

- In terms of potential *risks,* this model carries similar but more severe risks to Outcomes-based PBR in terms of costs, rates, profits, and incentives because the Hybrid model combines the complex Outcomes-Based PBR with untested and complex additional entities of the DSPP and IGO. Additionally, this model is likely to improve reliability and DER penetration, but carries the risk of proving to be overly complex and expensive, possible to the extent that its objectives (like reliability) are not met.

In terms of general comparison, the Hybrid model provides the most significant overall benefit to Hawaii (see, Task 2.2.6) but is also the most complicated model to study, implement, and operate, which makes use of that model riskier than the other models in terms of operations and finances. It is also the only model that requires additional legal changes to be made as a prerequisite to implementation. In contrast, there is more information available on the Outcomes-based PBR model and the Conventional PBR model with Light HERA, so there is less uncertainty in predicting costs and risks associated with those models.

2 Introduction, scope, and structure

2.1 Project description

DBEDT was directed by the State's legislature to Commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The Project Team, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria,[3] which include the following: achieve State energy goal; maximize consumer cost savings; enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; and eliminate or reduce conflicts of interest in energy resource planning delivery, and regulation.[4]

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

2.2 Role of this deliverable relative to others in the project

This deliverable corresponds to Tasks 2.3.1, 2.3.2, and 2.3.3 in the project scope of work. It draws from the high-level feasibility analysis in Task 2.2.3 and the top three ranked regulatory models in Tasks 2.2.6. Task 2.3.1, 2.3.2, and 2.3.3 specifically require a review of 1) the steps, timeline, and costs of establishing each regulatory model; 2) the legal changes necessary to implement each regulatory model; and 3) the financial and operational risks to ratepayers and shareholders for each regulatory model.

---

1 Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

2 Hawaii Contract No. 65595 between DBEDT and LEI, signed on March 23, 2017 (hereinafter "Hawaii Contract No. 65595")

3 H.B. 1700, Relating to the State Budget, June 24, 2016, available at: https://www.capitol.hawaii.gov/session2016/bills/HB1700_CD1_.pdf

4 Hawaii Contract No. 6559, "Scope of Services."

5 Hawaii Contract No. 65595, "Scope of Services."

Several of the issues discussed in this deliverable will be subject to further analysis in subsequent Tasks. With regards to the costs of the regulatory models, related tasks include:

- **Task 2.5.1 Estimated annual revenue requirement for each of the remaining regulatory models, including major costs by category; graphics comparing the three regulatory models.** The Project Team shall provide the expected annual revenue requirement for operation under each regulatory model through 2045, including the identification of all major cost elements.

- **Task 2.5.2 Assessment of system average retail rates for each regulatory model for an average residential, commercial, and industrial customer through 2045.** The Project Team shall forecast system average retail rates through 2045 using the revenue requirement from Task 2.5.1 and shall provide a comparison of forecasted retail rates for each regulatory model.

- **Task 2.5.3 Analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model.** The Project Team shall provide an overview of how costs vary and how the revenue requirement is calculated under each regulatory model.

With regards to the risks of the regulatory models, related tasks include:

- **Task 2.5.4 Analysis of any issues in the regulatory model that could impact the valuation of an electric utility and identify key risks to utility valuations for each regulatory model.** The Project Team shall provide an analysis of any variation to the valuation of an electric utility caused by a change in regulatory model.

With regards to the steps of the regulatory models, related tasks include:

- **Task 3.1.1 Assessing whether benefits of changes from ownership and regulatory model changes could be accomplished through changes in rate design.** The Project Team shall provide a qualitative discussion on the extent benefits of ownership and regulatory model changes, including the alignment of utility interests with State policy, can be accomplished through changes in rate design.

- **Task 3.1.2 Assessing how rate design compares to regulatory and ownership model changes considering overall market conditions.** The Project Team shall evaluate the ability of changes in rate design relative to ownership and regulatory model changes to (a) maximize consumer cost savings; (b) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs; (c) eliminate or reduce conflicts of interest in energy resource planning, delivery and regulation; and (d) align management, ownership, and ratepayer interests.

- **Task 3.1.3 Assessing the pros and cons of managing Hawaii's electricity sector with each county operating independently as compared to a multi-county model.** The Project Team shall include an analysis of the relative advantages and disadvantages of each county operating independently and collectively as a part of a multi-county model which may consist of the ownership of electric utilities in two or more counties. The Project Team shall evaluate the potential for each model to (1) achieve State energy goals, (2) maximize consumer cost savings, (3) enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs, and (4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation.

2.3 Structure of this report

This report, which responds to Task **2.3.1, 2.3.2, and 2.3.3**, discusses four primary aspects of transitions in utility regulation. The first is a listing of the **practical steps necessary** to transition from the current regulatory structure to a new structure, including an estimated timeline for the sequence and duration of these steps. The second is the **costs of such a transition**, considering both an estimate of any start-up costs related to a new regulatory model and any operating costs. The third is the **legal changes necessary** to enable a change toward the regulatory model. The fourth is an accounting and comparison of the **risks inherent in each regulatory model**.

As discussed in the Task 2.2.6 report, this report assesses the formation and risks of four models of utility regulation:

- The **Status Quo**.
- **Outcomes-based Performance-based Regulation.**
- **Conventional Performance-based Regulation** and a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**").
- **Hybrid Model** [Combination of Outcomes-based Performance-based Regulation ("PBR"), Distributed System Platform Operator ("DSPP"), and Independent Grid Operator ("IGO")].

In analyzing potential transitions in utility regulatory models, the Project Team made a series of assumptions about the specific transition that would occur in the different cases, which impacts the analytical approach taken in this report:

- The **Status Quo** model. Under this model, the utilities' rates are regulated by the PUC under a traditional cost of service ("COS") regulatory model in which the utility owns both generation and wire assets, and the PUC approves electricity rates to recover the cost of providing service through those assets. In addition to COS, the PUC also has integrated some components associated with PBR including multi-year rate plan, earnings sharing mechanisms ("ESM") between the utility and the customers for the HECO companies, revenue cap, and decoupling.

  Under the status quo model, there is no transition in the utility regulatory model. Therefore, the discussions of steps, acquisition costs, and legal changes are not relevant to this model and are not included. However, the status quo is included in the risk assessment, so that the risks of alternative models may be compared to that of the status quo. Since the eventual effects of the recent Ratepayer Protection Act (which requires a shift to a PBR regulatory model) are already separately considered in this study as a regulatory model, the status quo is represented in the risk assessment by the status quo under COS regulation.

- **Outcomes-Based Performance-based Regulation**. Under this model, regulators seek to incentivize the utility toward beneficial outcomes for society such as enhanced customer experience, improved utility performance, achievement of public policies and goals, and healthy financial performance. This model provides the utilities with the flexibility to determine their own preferred solutions and strategies to attain those desired outcomes. This model also includes expanded performance incentive mechanisms ("PIMs"), earnings sharing mechanism ("ESM"), total expenditure ("totex")[6] approach, an extended regulatory period, and more stringent reporting regimes.[7]

- **Conventional Performance-based Regulation** and a streamlined version of the Hawaii Electricity Reliability Administrator ("**Light HERA**"). In this model, the revenue requirements of the utilities are based on an indexing formula (inflation less productivity factor) for the second and third years of operation, and use of PIMs, ESM, and totex mechanisms are also included. This model also combines the use of Light HERA, which would perform the task of an ombudsman to oversee the interconnection process and reliability planning, and dispute resolution as necessary.

- **Hybrid Model** [Combination of Outcomes-Based Performance-based Regulation ("PBR"), Distributed System Platform Operator ("DSPP"), and Independent Grid Operator ("IGO")]. Under this model, an IGO would manage the dispatch and planning functions of both the transmission and distribution assets, and the utilities would serve as the DSPP to provide open access to distributed energy resources ("DER") and other providers offering energy management or customer data analytics services. Customers, service providers, DERs, and utilities would conduct transactions for energy and services on the modernized grid platform provided by utilities. An outcomes-based PBR would also be implemented to ensure utilities remain effective in their traditional functions while also performing as the DSPP.

Based on this analytical framework, the rest of this report is structured as follows:

---

[6] Under a totex approach, there is no distinction between the capex and operating expenditures as the utilities are incentivized to consider the whole life costs, rather than choose between a capital expenditure or an operating expenditure solution.

[7] Task 2.1.1 (Introduction to Regulatory Models) provides more description on the mechanisms under an Outcomes-based PBR.

- **A brief discussion of the Status Quo ownership model**. This encompasses a description of the status quo regulatory model.

- **Steps, timeline, costs, and legal changes necessary for a transition to a general Performance-based Regulation model**. Although there are three regulatory models specifically considered by this study, in this section of the report the Project Team initially assesses an overarching framework for Performance-based Regulation ("PBR") including a single, defined process for the implementation and operation of PBR in general, as well as an analysis of the overarching legal framework within which the transition to PBR would occur. The Project Team uses this approach for the sake of clarity and efficiency, since each of the individual regulatory models considered by this study includes some form of PBR.

- **Differentiation between the overarching PBR analysis and the elements of the specific models considered by this study in terms of transitional steps, timeline, costs, and legal changes.** Following the analysis of the steps, timeline, costs, and legal framework needed for the implementation of PBR in general, this section will highlight and explain the differences between the elements of the different models in general, and if relevant, as they relate to the overall PBR framework. Specifically, this will include the following subsections:

    - Outcomes-based PBR
    - Conventional PBR
    - Light HERA
    - DSPP
    - IGO

  Following the analysis of the specific requirements for each element of the selected regulatory models, the Project Team will conclude with a summary of the steps, timeline, costs, and legal requirements for each of the three models (Outcomes-based PBR, Conventional PBR + Light HERA, and the Hybrid model).

- **Assessment and comparison of risks inherent in each model.** The Project Team evaluated the risks of each model in a separate section to best facilitate comparison across regulatory models within specific risk categories.

3 Status Quo Model

Hawaii's current regulatory model is a traditional cost of service ("COS") model plus some incentive mechanisms and is described in detail, below. By definition, the status quo model does not entail any steps, costs, or legal changes to implement, and thus the Project Team will not discuss those here.

Under the status quo in Hawaii, as discussed in Task 2.1.2 (Current regulatory models), vertically integrated utilities in each county (HECO, MECO, HELCO, and KIUC) continue to function as major generators in their respective counties and continue to own and operate the transmission and distribution assets in their respective service areas. Generation in the State is also provided by several Independent Power Producers ("IPPs") and customer-sited and/or owned distributed generation ("DG"). The electric utilities are regulated by the Public Utilities Commission of the State of Hawaii ("PUC"). More specifically, the PUC:

- Regulates the utilities' rates, performance, and compliance with laws and regulations;
- Reviews applications for approval to construct transmission lines, to make large capital expenditures, to issue stocks and bonds, notes and other evidence of debt;
- Oversees and monitors the electric reliability, utility's service, operations (*e.g.*, safety), and resource planning;
- Initiates and conducts investigative proceedings; provides guidelines on various standards and regulations such as interconnection standards, procurement of generation, and Performance-based regulation; implements legislative policy and develops energy policy;
- Develops and adopts administrative rules in administrative rulemaking proceedings; and
- Generally, enforces public utility laws and regulations.[8][9]

The State government (Legislature and Governor) establishes the energy policies, then legislative enactments and resolutions are further developed, implemented and enforced by the PUC. The Hawaii State Energy Office ("HSEO"), within the Department of Business Economic

---

[8] S*ee generally,* Haw. Rev. Stat. Chapter 269; *see also,* http://puc.hawaii.gov/

[9] It is worth noting that the co-op KIUC is included here in terms of rate regulation by the PUC, and this is in contrast with how cooperatives are most frequently regulated on the mainland. However, the KIUC is unregulated in other respects (such as undergoing integrated resource planning); these exemptions were described in the legal section of the co-op chapter (Task 1.3.2).

Development & Tourism ("DBEDT"), assists in developing and implementing energy policy as may be provided by the State.

Electricity rates for the electric utilities are generally determined through a COS (sometimes referred to as "rate return regulation") approach with some components associated with Performance-based regulation such as the earning sharing mechanisms ("ESM"), penalties for not achieving certain performance standards (mostly in reliability), and multi-year rate plan. Although the State has made significant progress towards achieving its statutory 100% RPS target by 2045[10] under COS regulation, the State and the PUC have identified a misalignment of incentives under the current regulatory framework for the utilities that are not necessarily conducive to making the necessary changes for continued progress.[11]

Under the traditional COS model, the PUC sets rates that allow the utilities to recover costs incurred to provide their services plus a return on investment, so long as those costs are just and reasonable. Thus, under COS, utilities' earnings are realized through a rate of return on their capital investments, thereby incentivizing utilities to increase their capital investments to increase their associated return on investment. This rate structure may result in an "infrastructure bias" for utilities to deploy capital-intense solutions. Capital intensive infrastructure projects may be incompatible with efforts to achieve state energy goals, which include increased distributed generation, increased energy efficiency, and lower sales, among other things.

Because COS rate setting is based on the utilities' costs and encourages increasing costs through expanding rate base and capital investment, there are few incentives for utilities to employ cost-saving measures, reduce electricity sales, improve energy efficiency, integrate customer-sited

---

[10] Haw. Rev. Stat. § 296-92; As of 2017, Hawaii's RPS was more than 12% ahead of its statutory interim target of 15% by 2015. The 2017 RPS was 27.6%. Hawaii State Energy Office, Hawaii Energy Facts & Figures (June 2018), https://energy.hawaii.gov/wp-content/uploads/2018/06/HSEO_2018_EnergyFactsFigures.pdf at 1. See also *supra* note 15.

[11] Hawaii Session Laws, Act 005, April 24, 2018 (hereinafter "Hawaii Ratepayer Protection Act")

> "The legislature is concerned that the existing regulatory compact misaligns the interests of customers and utilities because it may result in a bias toward expending utility capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by third parties. The legislature concludes that it must ensure a change to the regulatory compact to promote decisions and strategies that will maximize public benefit, reduce ratepayer risk, and meet Hawaii's energy goals."

See also, Hawaii Public Utilities Commission, Order No. 35411 (Instituting a Proceeding to Investigate Performance-Based Regulation), Docket No. 2018-0088 (Apr. 18, 2018) at 3 (hereinafter "Order No. 35411").

> "An old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that change the way utilities make money and what value customers expect from their own electricity company. PBR attempts to address some of the issues and disincentives inherent in traditional cost-of service regulation ("COSR")."

generation, or establish other innovative services that do not involve a large capital investment. Such innovations are fundamental to achieving the 100% RPS target. According to the Hawaii PUC, "traditional [COS] may no longer properly incent the utility to adapt to the changing landscape, to meet the challenges of a renewable and distributed energy future, or to capitalize on the opportunities inherent to this transformation. Similarly, traditional [COS] may not equip regulators with the most effective tools or mechanisms to ensure that the utility effectively adapts to these changes, challenges, and opportunities."[12]

Because of the inherent challenges that COS regulation presents in terms of moving forward with the innovations required to fully transition to 100% RPS, Governor David Ige recently signed into law the Ratepayer Protection Act.[13] The new law orders the PUC to create "performance incentives and penalty mechanisms" by January 1, 2020, that break the direct link between allowed electric utilities' revenues and investment levels. The PUC also initiated a proceeding to Investigate Performance-based Regulation on April 18, 2018.[14]

---

[12] Order No. 35411 at 15.

[13] *See*, Section 4.3 discussion on the future of Hawaii-specific performance-based regulation; Hawaii Ratepayer Protection Act

[14] *See,* Section 3, discussion on the Future of Hawaii-specific performance-based regulation; Order No. 35411.

4 Performance-based Regulation

Performance-based regulation ("PBR") is an approach to rate regulation that provides a wide range of mechanisms that can weaken the link between a utility's rates and its unit costs and improve efficiency. PBR is best described as a broad regulatory approach that spans a large continuum ranging from light forms of PBR to more comprehensive forms. The choice of a light versus comprehensive PBR regime is linked with the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demand of and feedback from interveners.[15] One reason jurisdictions shift to PBR from COS regulation is the lack of incentives under the COS to both encourage prudent and efficient capital investment and overall cost efficiency.[16] Another reason jurisdictions shift to PBR is because PBR allows the utility sufficient freedom to decide how to best optimize its resources given the targets and objectives.

Hawaii is already well positioned to shift to the PBR regulatory framework due to its current implementation of some PBR measures within its traditional COS framework,[17] the recent adoption of the Hawaii Ratepayer Protection Act,[18] and focus on PBR by the PUC.[19] Even with such existing regulations and legislation, a shift to a full PBR regulatory framework will require additional steps, costs, and legal changes to implement.

The following sections will outline the steps and timeline involved in the regulatory transition to PBR in general. This analysis also includes the estimated costs of these transitions and the overarching legal requirements and feasibility of PBR in Hawaii. An analysis of the distinctions of the steps, costs, timeline, and legal requirements between the different types of PBR models considered by this study (Outcomes-based vs. Conventional), as well as the differences between the other elements of the regulatory models, will be addressed in Section 5.

---

[15] Task 2.1.1 at 29.

[16] It is worth noting that COS analysis and ratemaking principles are still important in PBR regulation. PBR regimes begin with a COS-based analysis of what the "going-in" rates should be. Moreover, COS principles including the opportunity for full cost recovery and commercially reasonable return on equity ("ROE") targets are still important tenets under PBR.

[17] Currently, Hawaii has the ESM, revenue cap, performance incentive mechanism, and flow through factors. See Task 2.1.1 at 33.

[18] Hawaii Ratepayer Protection Act. The act is currently undesignated in HRS § 269, but will be entitled "Performance incentive and penalty mechanisms." The act went into effect on July 1, 2018.

[19] Order No. 35411. The order opening an investigation on PBR is consistent with the PUC white paper, which called for the modernization of the electricity grid and regulations consistent with state energy goals. Hawaii Public Utilities Commission, Decisions and Order No. 32502 "Exhibit A: Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, issued April 28, 2014 (hereinafter "The Inclinations").

4.1 Overall Steps and Timeline Necessary to Establish a PBR Model in Hawaii

In the transition from traditional COS to PBR, the regulatory body begins by deciding that the shift to PBR is appropriate, and then follows a series of steps over the course of some months or years to achieve the full transition. The Project Team's approach to determining the steps, the timeline for transitioning to PBR, the overarching guidelines to be used in developing the model and implementation and operation procedures, and the actual steps and timeline are detailed below.

4.1.1 Approach to Assess Overall Steps and Timeline for Transition to PBR

The shift from a traditional COS framework to a PBR framework requires a significant amount of regulatory work and involves considerable stakeholder efforts to determine the appropriate PBR mechanism and to conduct in-depth analyses of sectoral and technical issues. To determine the steps and timeline that are likely to be necessary for Hawaii to transition to PBR, the Project Team first assessed the PBR process that Hawaii is already undertaking. Then, the Project Team looked to the experiences of other jurisdictions that have already transitioned from a traditional COS regulatory model to PBR to determine general guidelines for transitioning to PBR and to assess whether the PUC's process seems reasonable by comparison.

For this evaluation, the Project Team used annual reports and other publicly available publications from the jurisdictions' regulatory bodies. The jurisdictions considered in this evaluation included the United Kingdom, Alberta Canada, and the State of New York. Based on our review of these jurisdictions, the Project Team found that the steps and timeline for implementing PBR are most clearly represented by and most similar to those undertaken in Alberta, Canada, and the Project Team used this experience as an example for comparison in this section. It should be noted that Alberta's regulatory body, the Alberta Utilities Commission ("AUC"), has implemented what this study considers "Conventional PBR." Because this report considers both Outcomes-based PBR and Conventional PBR models, the Project Team specifically notes in later sections where divergences may occur when implementing and operating an Outcomes-based PBR model as opposed to a Conventional PBR model.

4.1.2 Guidelines for Overall Steps and Timelines for Transition to PBR

The first formal step in the PBR process is when the regulator or the utility expresses an intent to implement a shift. For example, in Alberta, the Alberta Utilities Commission ("AUC") highlighted the goal of developing a regulatory framework that allows incentives for the regulated companies to improve their efficiency while ensuring that the benefits from the increase in efficiency will ultimately benefit customers.[20]

---

[20] Alberta Utilities Commission. *Rate Regulation Initiative Decision 2012-237.* September 12, 2012. P. 5. Available at http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf (Hereinafter "AUC Decision 2012-237")

Following the expression of an intent to implement PBR, regulators should assess the following principles as they determine the goals of their proposed transition to PBR:[21]

- ***Incentives compatibility:*** Ratemaking should provide appropriate incentives to both companies and customers (although there may be some natural conflict there and tradeoffs may be needed).
- ***Financial stability and fair (commercially reasonable) rate of return***: Rates must be set at a level which enables the utility to meet its statutory obligations to serve while earning a commercially reasonable return (which continues to attract investors given the business risks) and generating sufficient cash flow to support necessary investment.
- ***Administrative simplicity and transparency***: Rates should be straightforward for customers to understand; customers should be able to calculate their monthly bills themselves and be able to understand why the rate is calculated in the prescribed fashion.
- ***Cost causation and avoidance of cross-subsidies***: To achieve the most efficient patterns of consumption, economic theory states that the customers that cause a cost to be incurred should pay for that cost.
- ***Non-discrimination***: Similarly situated customers should face similar terms and conditions.

Experience and best practices dictate that the regulator should also lay down principles to guide the utilities and other stakeholders in the development and implementation process, including developing responsive and relevant PBR proposals, and the regulator in evaluating the utilities' PBR proposals.

A move to PBR may also involve hiring an economic consultant to assist in determining the PBR approach, identifying appropriate components for the PBR such as incentives and performance standards, and reviewing other available data to produce forecasts of inflation and productivity trends.

Clear and open communication between the regulator and the utilities is also an important component of the PBR transition. Regulators and stakeholders should communicate regularly so that all parties have the same level of understanding about the PBR issues. Workshops and technical conferences may be a good way to maintain understanding between these parties and solicit feedback.

---

[21] For more information, see: Bonbright, Danielson and Kamerschen. 1988. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, VA; Bonbright, Danielson. 1961. Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, pp. 290-94); Weston, Fredrick. 1999. "Principles of Rate Design," www.raponline.org); and Woolf, Tim and Julie Michals, 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry," *The Electricity Journal,* Issue 8, Volume 8. October 1995.

Data availability is a critical element in the development of the PBR regime and is essential to improve the functionality of the PBR regulation over time. Because benchmarking and forecasting are such important features of PBR, it is necessary to have and collect reliable, comparable and accurate data throughout the PBR process.

Finally, as discussed in the Section 4.1.4 below, there are numerous steps involved in the PBR process and may take between 17-33 months to complete, depending on the PBR model.[22] The PBR process and timing are usually shaped by the number of utilities and interveners that participate in the regulatory process, the PBR framework the jurisdiction is using, and the regulatory generation the jurisdiction is in. Proceedings may take longer in the initial generation than in subsequent ones.[23]

4.1.3 Steps and Timeline Currently Contemplated in Hawaii

The State of Hawaii, through its legislation and a PUC docket instituting an investigation into PBR indicate that Hawaii, is now in the process of planning for a regulatory shift from COS to PBR.[24] The legislation requires the PUC to implement PBR by January 1, 2020,[25] and the PUC has already published an initial schedule of proceedings, listed below in Figure 1.[26] The proceedings are broken into two phases. Phase 1 encompasses Evaluation and Assessment, while Phase 2 involves Design and Implementation. During Phase 1, the PUC's obligations are to:

> (1) consider regulatory goals and outcomes to inform a Performance-based regulatory framework;
>
> (2) evaluate the current regulatory framework in Hawaii to examine which incentive mechanisms and regulatory components may not be functioning as intended or are no longer aligned with the public interest, and to identify specific areas of utility performance that should be targeted for improvement;

---

[22] The 17-33-month timeframe is based on a previous comparison between Alberta, Ontario, Australia, and the UK. *See* London Economics International LLC ("LEI"), Literature Review: regulatory economics and performance-based ratemaking – prepared for the Dept. of Energy of Nova Scotia, May 2, 2014, at 76 (Hereinafter "LEI Literature Review").

[23] LEI Literature Review at 78-79.

[24] Hawaii Ratepayer Protection Act., Order No. 35411.

[25] Hawaii Ratepayer Protection Act.

[26] Hawaii Public Utilities Commission, Decision and Order No. 35542 ("Admitting Intervenors and Participant and Establishing a Schedule of Proceedings"), Docket No. 2018-0088, issued June 20, 2018 (Hereinafter "Order No. 35542").

(3) assess which regulatory mechanisms can best address the specific areas of interest; and

(4) identify specific performance metrics, where appropriate.[27]

After the initial decision to proceed with PBR, the PUC began holding a series of technical workshops and requiring the parties to submit briefs following the workshop as a means of providing stakeholder outreach and education and soliciting stakeholder feedback. The technical workshops should establish a common foundation from which to view the existing regulatory framework, inform the need for modifications to that framework, and focus objectives and advance the proceeding in an efficient and productive manner.[28] Following this process, the PUC plans to create a proposal that should "(1) establish a goals-outcomes foundational hierarchy; (2) summarize an evaluation of the current regulatory framework and identify a set of regulatory outcomes that warrant further focus; (3) identify which regulatory mechanisms can best achieve each outcome; and (4) identify performance metrics for those outcomes best addressed by incentive mechanisms."[29] Then, the parties will have a chance to respond to the proposal before publication of the final decision and order, which will conclude Phase 1. The procedural schedule for these steps of Phase 1 is listed in Figure 1, below.

Figure 1. Hawaii PUC Phase 1 Procedural Schedule

Procedural Milestone	Date	Corresponding Step out of overall PBR Implementation Process*
Decision to transition to PBR	April 24, 2018	Step 1
Technical Workshop #1 – Kickoff / Goals – Outcomes	July 23-24, 2018	Step 2
Goals-Outcomes Brief	August 24, 2018	Step 2
Technical Workshop #2 – Regulatory Assessment	September 27, 2018	Step 2
Regulatory Assessment Briefs (submitted by the parties)	October 25, 2018	Step 2

[27] Order No. 35542 at 39-40.

[28] *Id.*, at 42.

[29] *Id*. at 60.

Technical Workshop #3 – Metrics	November 28, 2018[30]	Step 2
Metrics Briefs (submitted by the parties)	January 4, 2019 (originally proposed for December 2018)	Step 2
Phase 1 Staff Proposal	January 2019 – proposed date	Step 3
Statement of Position	February 2019 – proposed date	Step 3
Simultaneous IRs	March 2019 – proposed date	Step 3
Reply Statements of Position	March 2019 – proposed date	Step 3
Phase 1 Decision and Order	Subsequent to Reply Statements of Position ("SOPs")	Step 4

Source: Hawaii PUC[31]

Following completion of Phase 1, the PUC will build upon the work of Phase 1 and carry out the tasks set forth for Phase 2.

During this Design and Implementation phase (Phase 2), the PUC is tasked to "continue the collaborative process to: streamline and/or refine elements of the existing regulatory framework; develop incentive mechanisms to better address specific objectives or areas of utility performance; and implement other improvements to the regulatory framework that meet the goals and outcomes established in Phase 1."[32]

Under Phase 2, these tasks are divided into three tracks including PIMs, Revenue Adjustment Mechanisms, and Other Regulatory Reforms.[33] For the PIMs track, the PUC will establish performance metrics and reporting requirements, which correspond to the development of performance targets, financial mechanisms, and performance evaluation.[34] For the revenue adjustment mechanism track, the PUC will begin development or refinement of a revenue

[30] Links to the video recordings of the July and September workshops are available here: http://puc.hawaii.gov/energy/pbr/ . The link to the slides for the November workshop is listed in the docket, posted on Dec. 11, 2018.

[31] Order No. 35542 at 57-61 contains the initially proposed schedule of proceedings. Specific dates or changes to the schedule have been updated using the Docket Documents page (dms.puc.hawaii.gov) for this docket (2018-0088). *The overall PBR process is detailed in Section 4.1.4, infra.

[32] *Id*. at 40.

[33] *Id*. at 52.

[34] *Id*. at 53-54.

adjustment mechanism.[35] And for the Other Regulatory Reforms track, the PUC will consider additional strategic changes to the regulatory framework such as non-wires alternatives and shared savings mechanisms, and new revenue opportunities.[36]

It should be noted that the detailed initial schedule of proceedings extends only through the Phase 1 Decision and Order, and that the official schedule of proceedings provides a slightly different timeline than the one originally projected in the initial order.[37] Despite the increased timeline for Phase 1 from 9 months in the initial order to 11 months in the order establishing a schedule of proceedings, and the lack of timeline for Phase 2 which could both indicate a delay in the overall timeline, it seems reasonable to assume that the PUC is still working towards the January 1, 2020 deadline.

4.1.4 Steps and Timeline Required for Transition to PBR: Alberta Example

The Project Team's assessment of the steps and timeline generally required for the transition to PBR is primarily informed by the experience of Alberta, Canada.[38] There, the transition from COS to PBR required nine steps that took approximately 33 months to complete.[39] This process and timeline are detailed below to provide an understanding of what could be anticipated for Hawaii's PBR implementation process, and to show how the PUC's implementation plan and timeline compare to a successfully completed PBR implementation.

Figure 2. Steps and Timeline to Implement PBR in Alberta

---

[35] *Id.* at 55.

[36] *Id.* at 56.

[37] In Order No. 35411 Instituting a Proceeding to Investigate Performance Based Regulation at 55, the PUC expected Phase 1 to conclude in approximately 9 months, and Phase 2 to take approximately 12 months, resulting in a 21-month long process to complete the PBR, in time to meet the January 1, 2020 deadline imposed by the legislature. However, in the subsequent Order 35542 Admitting Intervenors and Participant and Establishing a Schedule of Proceedings, the schedule published is more detailed and does not adhere to the initial estimates. Instead, the schedule for phase 1 concludes after 11 months, and no detail is provided for phase 2.

[38] Alberta's transition from COS to PBR is a good example of the steps other jurisdictions (especially Hawaii due to its relatively similar size and the fact that it has already begun the process of transitioning to PBR). Additionally, Alberta was already considering PBR when the AUC was created in 2008. At the point when Hawaii created legislation and a PUC docket for PBR, it had also already been contemplating the shift (see, research involved in producing the initial order No. 35411, as well as the Inclinations in Docket No. 2012-0036, Order No. 32052).

[39] LEI Literature Review at 79.

It should be noted that for Outcomes-based PBR, which makes use of more PBR mechanisms and can be more complex overall, the Project Team anticipates the timeline could be longer than the one used in by Alberta, Canada and proposed by Hawaii. This will be explored in greater detail in Section 5.

Step	Procedural Milestone	Timeline
1.	Statement of Intent and Release of Schedule	Month 1
2.	Stakeholder Education and Outreach	Months 2 – 4
3.	Initial Publication of Guiding Principles and Stakeholder Feedback	Month 5
4.	Finalization of PBR Guiding Principles and Framework	Month 6
5.	Commencement of Independent Study	Month 7
6.	Conclusion and Results of Total Productivity[40]	Month 12
7.	Interested Parties Submit PBR Proposals	Month 19
8.	Intervention and Hearings	Months 20-33
9.	PBR Decision Issued	Month 33

Source: AUC

4.1.4.1 Step 1: Statement of Intent and Release of Schedule

In February 2010, or Month 1 of Alberta's transition to PBR, the Regulator (the AUC) announced its intent to transition from COS regulation to PBR regulation and released a preliminary schedule for the PBR implementation. The initial schedule set out an intention to apply a PBR formula for distribution rates that would begin on July 1, 2011 for a five-year term.[41] The schedule in the letter lays out a more immediate step for the implementation of PBR, including a round table discussion among utility companies and interested parties to set dates for submissions and address other issues, scheduled for March 25, 2010 (one month following the initial letter). Finally, the schedule also included that a proceeding is to be initiated by the Commission during the first PBR term to assess the PBR's success and determine adjustments or re-basing before the next PBR period.[42]

In Hawaii, the statement of intent was expressed by the Hawaii Ratepayer Protection Act, which was signed by the Governor on April 24, 2018, and requires the transition to PBR. The statement of intent was also supported by Docket 2018-0088, which was opened on April 18, 2018, by Order

[40] Total Productivity Study is generally used for PBRs with an indexation mechanism such as the "Conventional PBR" in our PBR mechanisms.

[41] Alberta Utilities Commission, Ltr to Interested Parties "Rate Regulation Initiative Round Table," at 3, February 26, 2010.

[42] *Id*. Feb. 26 2010 letter at 3.

No. 35411 to investigate PBR. Docket 2018-0088 has since become the official vehicle for designing the PBR regulatory model that is required by the Act. The initial Order described a schedule in which Phase 1 would conclude in 9 months, and Phase 2 would conclude in 12 months.[43] However, the Commission released an official Schedule of Proceedings in Order No. 35542 that provides information about both Phases but an actual schedule only for Phase 1 which takes about 11 months to complete instead of 9 months. The schedule for Phase 2 has not yet been released.[44]

4.1.4.2 Step 2: Stakeholder Education and Outreach

In Months 2-4, the AUC provided stakeholder engagement opportunities, a PBR educational and consultation workshop for stakeholders, and a short proceeding to receive input on the principles that should guide PBR development in Alberta.[45]

The first stakeholder engagement effort was the aforementioned roundtable discussion. At the roundtable discussion, all the electricity and natural gas distribution companies under the AUC's regulatory jurisdiction, as well as some other interested parties, were present. Attendees agreed both that rate regulation review could proceed separately from PBR implementation and reached consensus on three preliminary terms regarding PBR implementation. These initial terms were to (1) establish common guiding principles for implementing PBR, (2) organize a workshop to provide participants with an understanding of PBR, and (3) to extend the deadline. The Commission accepted the items of consensus that arose from the meeting and adjusted its steps and timelines as it continued forward with the PBR process.[46]

Based on the consensus reached in the Round Table Discussion to achieve a common level of understanding on the PBR implementation, the AUC engaged the Van Horne Institute to conduct a 2-day long PBR workshop with all the participants from the Round Table Discussion.[47] The AUC also set out a schedule for determining the guiding principles as agreed upon during the Round Table Discussion. In another letter, the schedule is set forth with deadlines for the submission of proposed principles by parties on June 10, 2010, and comments by parties

---

[43] Order No. 35411, at 55.

[44] Order No. 35542 at 57.

[45] Alberta Utilities Commission, Letter to Interested Parties "Rate Regulation Initiative Application 1606029 ID 566: Process Steps," at 2, April 9, 2010.

[46] *Id.*, Apr. 9, 2010 letter at 1-2

[47] *Id.*, Apr. 9, 2010 letter at 2

respecting the submissions on June 17, 2010. The principles would be decided and published by the AUC on July 8, 2010,[48] but were actually published on July 15, 2010 in Bulletin 2010-20.[49]

In Hawaii, there are three technical workshops scheduled by the PUC as part of the PBR docket. As noted in Section 4.1.3, above, the technical workshops are intended to be collaborative and informative, and provide the parties with a common knowledge from which to assess the existing regulatory framework and to identify improvements and objectives for the PBR model. These technical workshops are similar in nature to the roundtable discussions that were held in Alberta.

4.1.4.3 Step 3: Initial Publication of Guiding Principles and Stakeholder Feedback

In Month 5, the AUC developed and released proposed guiding principles for the PBR and stakeholders provided inputs to these principles.

In Hawaii, initial guiding principles were published in the Hawaii Ratepayer Protection Act and the Order by the Commission opening the PBR docket.[50] In the Act, the guiding principles are to "directly tie an electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels"[51] and a preliminary list of performance incentives and penalty mechanisms that the Commission must consider.[52] In the Docket, the Commission notes its interest in PBR mechanisms "that result in: greater cost control and reduced rate volatility; efficient investment and allocation of resources regardless of classification as capital or operating expense; fair distribution of risks between utilities and customers; and fulfillment of State policy goals."[53] Stakeholders were able to provide feedback as intervenors in the docket process.

4.1.4.4 Step 4: Finalization of the PBR Guiding Principles and Framework

In Month 6, the AUC finalized and issued the PBR guiding principles as well as the type of PBR framework it wanted the utilities to use. The principles are listed below:

- Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

---

[48]Alberta Utilities Commission, Letter to Interested Parties – Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Process for Development of Guiding PBR Principles, May 14, 2010.

[49] Alberta Utilities Commission, Bulletin 2010-10, Rate Regulation Principles – PBR, July 15, 2010, available at: http://www.auc.ab.ca/News/2010/Bulletin%202010-20.pdf .

[50] Hawaii Ratepayer Protection Act; Order No. 35411, at 5.

[51] Hawaii Ratepayer Protection Act at 5.

[52] *Id*. at 5-6. "In developing performance incentive and penalty mechanisms, the public utilities commission's review of electric utility performance shall consider, but not be limited to, the following…"

[53] Order No. 35411 at 5.

- Principle 2: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
- Principle 3: A PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.
- Principle 4: A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
- Principle 5: Customers and the regulated companies should share the benefits of a PBR plan.

In Hawaii, the final PBR principles are still being developed through the Phase 1 process.

4.1.4.5 Step 5: Commencement of Independent Study

In Month 7, the AUC hired an independent consultant, the National Economic Research Associates, Inc. ("NERA") to conduct a total factor productivity study, or studies ("the TFP Study"). The TFP study is to determine the appropriate productivity factor to be used in the regulatory period. In our PBR options, this applies to the Conventional PBR model. The requirements of the TFP study are as follows:

a) apply to Alberta gas, and electric utilities
b) compare productivity for gas and electric utilities to economy-wide productivity;
c) make the comparison transparently;
d) use publicly available data;
e) be for use and testing in a regulatory proceeding and for adjusting rates for Alberta electric and gas utilities; and
f) be filed in AUC Proceeding 566 – Rate Regulation Initiative prior to December 31, 2010.[54]

In addition to creating the study and following the filing of the utilities PBR proposals, NERA was expected to support the TFP Study on an as-required basis determined by its counsel in any subsequent regulatory proceedings. The Commission also noted that the TFP study would be supporting evidence for a basic X-factor but did not include any estimate of a stretch factor or any other factors.[55]

In Hawaii, a TFP study might be needed for the Conventional PBR. For the Outcomes-based PBR, there is no need for a TFP study.

[54] Alberta Utilities Commission, Letter to Interested Parties, Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Retention of Consultant to Develop a Basic X Factor, Sept. 8, 2010.

[55] *Id*. at 2.

4.1.4.6 Step 6: Conclusion and Results of Total Productivity Study

In Month 12, the independent consultant previously hired submitted its report on the total productivity study.[56]

In Hawaii, a TFP study might be needed for Conventional PBR but has not been initiated. Therefore there is no date yet as to when such a study would be concluded.

4.1.4.7 Step 7: Interested Parties Submit PBR Proposals

In Month 19, other interested parties submitted PBR proposals, and the PUC solicited statements of intention to participate.

In Hawaii, there is no date yet as to when utilities need to submit their PBR plans. However, the Act specified that PBR should be implemented starting January 1, 2020.

4.1.4.8 Step 8: Intervention and Hearings

In Months 20-33, Interveners submitted information requests and utilities submitted information responses; oral hearings; utilities submitted arguments.

In Hawaii, many third parties have already applied for and been granted intervenor status in the PBR docket. However, since there is no date yet as to when utilities need to submit their PBR plans, there is no date yet for intervention and hearings related specifically to PBR plans.

4.1.4.9 Step 9: Decision Issued

In Month 33, the AUC issued its PBR decision.

As was stated above, the deadline for the Hawaii PBR implementation is January 1, 2020, which would be Month 21 of the process.

4.1.5 Implications of the AUC timeline on Hawaii's PBR Implementation Process

When comparing the steps taken by the AUC for its PBR Implementation, it is apparent that although the actual steps are not identical, the overall process is quite similar. Both begin with a decision to transition to PBR, and to open a docket and release an implementation plan and schedule. Both continue to develop the PBR by engaging in stakeholder education and engagement (e.g., technical workshops), and used stakeholder feedback to guide the development of the regulatory framework.

Nevertheless, there are also differences between the two markets. For one, there are fewer utilities that would participate in the PBR in Hawaii (3 utilities) compared to in Alberta (6 utilities). This might mean shorter timeframe for Hawaii. Second, in Alberta, the PBR is not only for electric utilities but also for gas utilities. In Hawaii, since it's only the electric utilities that would be under

---

[56] *See* Alberta Utilities Commission, Letter NERA Total Factor Productivity Working Papers, Jan 21, 2011, indicating that the NERA TFP Study was released to the parties.

PBR, then the discussions would be easier and might be shorter. Finally, the AUC already had some experience handling the PBR before implementing it to the other utilities. ENMAX Power Corp. filed its PBR regime application with the Alberta Energy and Utilities Board (which later became the AUC) in 2007, and the AUC released its decision in 2009, one year before the AUC launched its initiative to reform electricity and gas utility rate regulation. This might mean that the timeline would have been longer if the AUC did not have previous experience on PBR.

Although the Hawaii PUC has not yet published the schedule of proceedings for Phase 2, it is reasonable to conclude, based on the similarities of in Phase 1 of the PUC's implementation plan to the initial steps of the AUC implementation process that Phase 2 of the PUC's plan will also be similar to the later steps in the AUC process, including a period of at least several months for the utility companies to develop and submit PBR proposals, followed by another period of several months for intervention and hearings prior to the issuance of the final PBR decision.

Another implication of the similarities between both approaches is that it seems plausible that they would have similar timelines. This is notable because the PUC is working on a 21-month timeline (beginning in April 2018, with a deadline on January 1, 2020), and the AUC completed its PBR implementation in 33 months. If Hawaii were to take around 33 months to complete its PBR implementation instead of its 21-month goal, the process would be completed at the end of 2020 or early 2021. Although it is certainly possible that the PUC will meet its original timeline, it is also important to note that the similarities between the PUC and AUC's process for implementing PBR creates some uncertainty in the Hawaii timeline.

Furthermore, if the PUC decides to implement Outcomes-based PBR instead of Conventional PBR, the Project Team anticipates that the broad steps for PBR will remain the same, but the entire process may take longer due to the greater complexity of an Outcomes-based model. The increased timeframe may also include the repetition of some steps due to the greater number of mechanisms that are used under an outcomes-based model than a conventional model. This will be elaborated on in Section 5.1.1, infra.

4.2 Transition Costs

In the scenario in which Hawaii shifts from a COS regulatory framework to a PBR framework for the regulation of electric utilities, the costs of the transition will include increases in time, expense, and use of other resources by the regulatory body to complete the steps described in the prior section and to fulfill new responsibilities set forth by the PBR framework. Transition costs can be difficult to determine because public documents often exclude specific cost allocations. However, by examining the overall costs incurred by other jurisdictions that made this transition before, the Project Team estimates costs that Hawaii can reasonably anticipate if were to pursue this regulatory option.

4.2.1 Cost Calculation Approach

As stated previously in this report, Hawaii can learn from the experiences of other jurisdictions in considering the transition from a traditional COS regulatory model to PBR. For this task, the Project Team assessed the experiences of several jurisdictions, and focused on the data from

Alberta, Canada, due to the broad similarities between PBR models, and the availability of sufficient data from which inferences could be made. The Project Team assessed the average annual costs of the AUC before, during, and after the transition from cost of service to Performance-based ratemaking. This allows for an estimate to be made both of the direct costs of transitioning from one model to the other (during the specific years in which Alberta was developing its PBR framework) as well as any long-term change in the cost of regulating utilities under the COS and PBR approaches. The Project Team then bounded this cost estimate by scaling these impacts to the average annual budget of the state of Hawaii.

4.2.2 Transition Costs in Alberta, Canada

Alberta, Canada, transitioned from COS regulation to PBR (RPI-X) only a few years after the AUC was formed. The AUC was created in 2008 as a result of the Alberta Utilities Commission Act. The Act dissolved the Energy and Utilities Board, which had previously been responsible for utility regulation into two separate entities: the AUC, which had an expanded mandate to regulate Alberta's utility sector, and the Energy Resources Conservation Board, which had jurisdiction over Alberta's oil and gas resources' development.[57] From its inception in 2008, the AUC took a Performance-based approach to its own operations and planned to implement PBR for its utilities' regulation, and began planning for PBR implementation soon thereafter, ramping up in 2010 with its announcement to interested parties that it was "beginning an initiative to reform utility rate regulation in Alberta."[58] In 2012 (fiscal year 2013) PBR was implemented,[59] with revisions made in 2013 and 2014. The initial PBR term is set to end in 2017, with the next term set for 2018-2022. The planning for the second term began in 2015-2016.

Based on the context of annual reports and other documents, the AUC's primary activities over the period from 2008-2018 consisted of initiating operations (including developing a mission statement and goals and building up staff), conducting normal regulatory business (e.g. processing rate applications, issuing decisions, managing complaints), improving efficiency in its own operations (including implementation in FY2014 of a new E-Filing System), and most notably completing the steps described in Section 4.1 to implement PBR.

As the AUC fiscal year begins in April, AUC's announcement in February 2010 to pursue PBR came near the end of its 2010 fiscal year. The 33-month timeline described above encompassed the entirety of the 2011 and 2012 fiscal years, as well as seven months of the fiscal year 2013. Based on this timeline, the Project Team considers the AUC Fiscal Years of 2011-2013 to encompass the

---

[57] Alberta Utilities Commission, "100 Years of Service and Counting," http://www.auc.ab.ca/Pages/centennial.aspx .

[58] AUC Decision 2012-237 at 221.

[59] See generally, *Id*.

contact:
Ryan Cook/Arielle Magliulo
503-467-7107
ryan.cook@cadmusgroup.com

transition period from COS to PBR. The 2009 and 2010 fiscal years are treated as the pre-transition period,[60] and fiscal years 2014-2018 as the post-transition period.

The AUC's inflation adjusted (in 2018 Canadian dollars) average operating expense for the pre-transition period from FY2009-2010 was roughly $33.6 million per year.[61] During the transition period from FY2011-2013, this expense increased to roughly $37.3 million, which represents a 10.9% increase over the pre-transition years' average operating expense. In the post-transition years from FY2014-2018, the average annual expense returned to roughly $33.6 million.[62]

These costs, which are summarized below in Figure 3, indicate a general annual cost increase of approximately $3.67 million CAD, or $2.78 million US,[63] over the three-year transition period.

Figure 3. Alberta PBR Transition Costs

Time Period	**Average Annual Regulatory Expense (2018 Canadian Dollars)**	**% Change from Pre-Transition Period**
Pre-Transition (FY2009-FY2010)	$33,598,102	N/A
Transition Period (FY2011-FY2013)	$37,267,590	+10.9%
Post Transition (FY2014-FY2018)	$33,645,569	+0.1%

Source: AUC, Annual Reviews for FY2009-2018[64]

60 Fiscal year 2008 is excluded as full data is not available. The agency was established on January 1, 2008, and FY 2008 ended on March 31, 2008, resulting in a 3-month long and incomplete fiscal year.

61 Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx . The Project Team used the information from these reports to calculate average expenses for ranges of years listed above, and we also adjusted for currency and inflation.

62 *Id.*

63 This analysis incorporates a currency exchange rate of 1 US Dollar to 1.32 Canadian dollars, effective on July 24, 2018.

64 Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx . The Project Team used the information from these reports to calculate average expenses for ranges of years listed above, and we also adjusted for currency and inflation.

4.2.3 Estimate of Transition Costs of PBR in Hawaii

In Hawaii, the Commission is responsible for regulating all public utilities, including the electric utilities that serve the islands, as discussed earlier. Over the past five years, the costs of PUC's regulatory activities have been somewhat stable, with average annual direct PUC expenditures of $6.3 million (inflation-adjusted to 2018 dollars).

Like Alberta, Hawaii is embarking on a multi-year process of transitioning towards PBR. The Project Team anticipates these efforts to require a broadly similar timeline. While the timelines laid out by the Hawaii legislature (18 months)[65] and PUC (21 months)[66] are somewhat shorter than the 33-month schedule experienced by Alberta, based on stakeholder conversations conducted as part of this task, the Project Team considers it reasonable to expect that some planning activities may extend beyond this initial 18 to 21-month period. Therefore, the Project Team considers the three-year transition period identified in the above analysis of AUC's annual costs to be a useful guide.

Scaling the transition costs experienced by AUC to Hawaii has a degree of inherent uncertainty, as the overall annual expense of AUC is roughly four times greater than that of the Hawaii PUC ($25.5 million US per year in Alberta compared to $6.3 million US in Hawaii).[67] It is expected that the PBR transition costs experienced by AUC and the PUC will scale somewhat with size, due both to the larger overall size of Alberta compared to Hawaii and the larger number of affected utilities. However, it is also reasonable to expect that some costs may be fixed and similar in nature between the two jurisdictions. Therefore, the Project Team provides two estimates for annual cost impacts in Hawaii, one based on the overall cost increase experience by AUC in the three-year transition period, and one based on the percentage change in costs. As noted in Figure 4 below, this approach yields an effective range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 dollars) per year over a three-year transition period (for a total transition cost of between and $2.0 million and $8.3 million). This is equivalent to a 10.9% increase in the PUC's annual average expenses in the period from 2013 to 2017.

Based on the experience of AUC to date, the Project Team does not project a long-term change in regulatory costs beyond this transition period.

[65] SB2939, or 2018 Act 005, The Hawaii Ratepayer Protection Act, went into effect on July 1, 2018, and requires PBR implementation by January 1, 2020.

[66] The PBR docket 2018-0088, Order No. 35411, states that the PUC anticipates Phase 1 to take 9 months to complete and Phase 2 (Design and Implementation) to take 12 months. Thus, the total time anticipated by the PUC in its initial order to implement PBR is 21 months. At 55.

[67] Hawaii Public Utilities Commission, Annual Reports for Fiscal Years 2013-2017, available at: http://puc.hawaii.gov/reports/annual-reports/; Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx. The Project Team used the information from Hawaii PUC reports to determine the average expense for the range of years listed above, adjusted for inflation. We also used the calculations cited in footnotes 60 and 62, supra, to determine the percentage rate of increase due to PBR transition.

Figure 4. Anticipated Hawaii PBR Costs

Cost Type		Cost (2018 Dollars)
Average Annual HI PUC Expense (2013-2017)		$6,252,965
Expected Annual PBR Transition Cost in Three-Year Period	Low Estimate (Based on AUC Percent Change)	$682,931
	High Estimate (Based on AUC Dollar Change)	$2,779,915

Source: PUC and AUC[68]

4.2.4 Unique Cost Factors for Achieving Conventional PBR in Hawaii

Unique cost factors for achieving PBR in Hawaii may include the following:

4.2.4.1 Existing Legislation

As will be discussed in the following section,[69] Hawaii recently adopted legislation that essentially requires the shift from COS to PBR by changing the requirements for what the PUC considered "just and reasonable."[70] Additionally, the PUC recently opened a docket to investigate PBR and appears to have already made some progress in their research.[71] Therefore, it seems reasonable to conclude that many of the initial costs of PBR implementation are already being incurred.

4.2.4.2 KIUC Exemption from PBR Legislation

KIUC is not included in Hawaii's new PBR legislation and will continue to regulate rates under a COS model.[72] Although this represents a unique situation, it should be noted that KIUC represents electricity generation and distribution for approximately 5% of the State of Hawaii's population, whereas the HECO companies provide electricity to the other 95% of the population. Although it was not possible to separate PUC expenses on KIUC regulatory activities from the

---

68 *Id.*

69 Legal Considerations, infra at 4.3.

70 Hawaii Ratepayer Protection Act: "The purpose of this Act is to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a performance-based model for determining utility revenues."

71 Order No. 35411, Instituting a Proceeding to Investigate Performance-Based Regulation, April 18, 2018.

72 Order No. 35411, Instituting a Proceeding to Investigate Performance-Based Regulation, April 18, 2018, at 9-10.

PUC financial data set, the effect of the aggregate data from the PUC on our cost estimates is likely to be relatively insignificant due to the small size of KIUC.

4.2.5 Conclusions for Anticipated Transition Costs of PBR in Hawaii

We base our expectations of PBR transition costs in Hawaii on the comparable experience of Alberta. The AUC undertook a transition process to implement PBR as detailed in the steps listed in Section 4.1.4, supra, during FY 2011-2013. During the transition period, costs increased by 10.9%, and then returned to pre-transition levels after the transition period concluded. This indicates that PBR incurs significant costs during the initial transition period, but not in its normal operations after its successful implementation. Notably, in Alberta after implementation of the initial PBR term, the AUC operated under PBR and began planning the second PBR period during 2015-2016 and still maintained the costs that were comparable to pre-transition (rather than transition) period costs.[73]

As previously discussed, the Alberta example is representative of the regulatory shift from COS to PBR and may be used as a general guide for such transitions. In addition, it is a good point of comparison for Hawaii due to its relatively similar size, and because the AUC was already considering PBR at its inception, so its financial data may more closely reflect the situation of Hawaii, which already has begun the process of PBR planning.

Using these general guidelines as determined from the Alberta example, the Project Team determined that the transition costs in Hawaii will be roughly 10.9% higher than their costs in the pre- or post-transition periods. Again, the Project Team notes that it is possible these costs may be larger if the PUC ultimately uses a more complex PBR model.

4.3 Overarching Legal Analysis for Implementation of Performance-based Regulation

The legal analysis for implementing a new regulatory model, including PBR and any variation the Commission may ultimately choose, should be based on the following general legal analysis of the regulation of public utilities in Hawaii. Specific caveats for each specific regulatory model considered by this study will be included in the relevant subsequent sections that provides details on each specific model.

4.3.1 Existing Legal Framework of the Hawaii Public Utilities Commission

This section details the existing legal framework for the regulation of public utilities in Hawaii, including the federal, state, and local laws that provide the Commission with regulatory authority, and the nature and extent of the PUC's regulatory authority. Due to the apparent nature of this legal framework, this section will focus primarily on the relevant state laws and prior instances of the PUC's exercise of such authority. This section concludes that the existing framework grants the PUC broad power to regulate the state's electric utilities, such as by

[73] See AUC annual report and financial data, FY 2016.

implementing PBR.[74] The application of this broad authority to each regulatory model will be detailed in the respective sections in the report. However, the Project Team notes that this authority does not expressly include the ability to create a new entity like an IGO. This specific situation will be detailed in Section 5.4.5.

4.3.2 Federal Law

The Federal Energy Regulatory Commission ("FERC") is the federal agency within the US Department of Energy that is responsible for regulating the interstate transmission of electricity, natural gas, and oil, and the sale of electric energy at wholesale in interstate commerce.[75] FERC also reviews proposals to build liquid natural gas terminals and interstate pipelines, conducts licensing in and inspection of private, municipal and state hydroelectric projects, ensures the reliability of the high voltage interstate transmission system, monitors and investigates energy markets, and oversees environmental matters related to natural gas and hydroelectric projects and major energy policy initiatives.[76]

Hawaii is not subject to FERC jurisdiction to regulate electricity transmission or wholesale sales because such transmission and sales do not constitute interstate commerce,[77] which is the basis for FERC's jurisdiction.[78] Hawaii is an island chain, whose own grid system consists of separate grids for each island within the state.[79] In contrast, in the continental US grids span across

---

[74] Regulation of KIUC is less certain. Currently, the PUC has authority to regulate them, but state law provides that electric cooperatives such as KIUC may apply for exemption from PUC regulation. *See* Haw. Rev. Stat. § 269-31.

[75] 16 U.S.C. § 824(b)(1).

[76] FERC, "What FERC Does," https://www.ferc.gov/about/ferc-does.asp.

It is worth noting regulation of *retail* electricity and natural gas sales to customers, *inter alia*, is considered outside of FERC's jurisdiction. *Id*, emphasis added.

[77] Under the 10th Amendment of the U.S. Constitution, States are granted police power to protect the public welfare, health and safety. *See* "The powers not delegated to the United States by the Constitution, or prohibited by it to the States, are reserved to the States respectively, or to the people." U.S.C. Const. Amend. X.

[78] "The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce…. The Commission [FERC] shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used in the generation of electric energy or over facilities used in local distribution or only *for the transmission of electric energy in intrastate commerce*, or over facilities for the transmission of electric energy consumed wholly by the transmitter." 16 U.S.C. § 824(b)(1), emphasis added.

[79] Hawaiian Electric Company, Inc., "Power Facts – Power Supply," (last visited Aug. 21, 2018), https://www.hawaiianelectric.com/about-us/power-facts/power-supply .

multiple states, allowing for electricity generated in one state to be transmitted and sold in other states.[80]

The North American Reliability Corporation ("NERC") is a nonprofit organization that was granted the designation of the Electric Reliability Organization authorized and required by the Energy Policy Act of 2005.[81] Notably, upon receiving this designation, NERC filed mandatory Reliability Standards with FERC and Canadian authorities, 83 of which were approved by FERC in March 2007 and are legally enforceable.[82] As the name of the organization suggests, NERC's reliability requirements apply to the North American bulk power system.[83] Hawaii is also not subject to the jurisdiction and authority of NERC due to its geographic location and exclusion from the North American bulk power system.[84]

4.3.3 State Law

The State of Hawaii, to the extent that it is not preempted by federal law, is governed by the Hawaii State Constitution, the Hawaii Revised Statutes ("HRS") and the Hawaii Administrative Rules ("HAR"). Specifically, the PUC is responsible under state law for the regulation of public utilities, including electric utilities like the HECO companies. Furthermore, the state's authority to regulate the public utilities preempts the counties' efforts to do the same, although county governments may still participate in proceedings before the PUC.[85]

---

[80] United States Dept. of Energy, United States Electricity Industry Primer (July 2015), available at https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf at 11.

[81] Energy Policy Act of 2005, Pub. L. 109-58 (Aug. 8, 2005), available at https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf; NERC, Reliability Legislation (last visited Aug. 21, 2018), available at https://www.nerc.com/AboutNERC/keyplayers/Pages/Reliability-Legislation.aspx .

[82]*See e.g*., *Summary of Reliability Legislation (Source: Section 1211 of H.R. 6, the "Energy Policy Act of 2005"),* NERC, (Aug. 8, 2005), available at https://www.nerc.com/AboutNERC/keyplayers/Documents/Summary_of_Reliability_Legislation-20050808.pdf

[83] NERC, "About NERC," NERC (last visited Aug. 21, 2018), https://www.nerc.com/AboutNERC/Pages/default.aspx

[84] The North America bulk power system includes the continental US and Canada. *See* NERC, "Key Players" (last visited Aug. 21, 2018), https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx).

[85] *See, e.g.*, Hawaii Public Utilities Commission, Order Granting Intervention, Docket No. 2008-0273, issued November 28, 2008 (Order grants the City and County of Honolulu intervenor status in a proceeding to investigate the implementation of feed-in tariffs).

4.3.3.1 Legal Authority of the PUC

The PUC is a state agency that is authorized and structured by Chapter 269 of the Hawaii Revised Statutes, which is entitled "Public Utilities Commission."[86] This HRS chapter provides the general powers and duties of the PUC,[87] lists all relevant definitions,[88] and provides detail on the PUC's authority to engage in specific conduct including ratemaking[89] and initiating investigations of public utilities or other relevant issues.[90] The Hawaii Revised Statutes are also where legislative actions are codified. In the context of the PUC, this has included many measures, such as the State's 100% RPS goal,[91] the development of a Community-Based Renewable Energy tariffs by the utilities with required review by the PUC,[92] and most recently, the Hawaii Ratepayer Protection Act.[93] For procedural guidance, the PUC is also governed by HRS chapter 91 on Administrative Rulemaking for all state agencies,[94] as well chapter 6-61 in the Hawaii Administrative Rules that provides the rules of practice and procedure for PUC proceedings.[95]

4.3.3.1.1 The General Powers and Duties of the Public Utilities Commission.

The general powers and duties of the Public Utilities Commission are as follows:

> *The public utilities commission shall have the general supervision hereinafter set forth over all public utilities,*[96] *and shall perform the duties and exercise the powers imposed or conferred upon it by this chapter. Included among the general powers of the commission is*

[86] Haw. Rev. Stat. § 269-1 et seq.

[87] Haw. Rev. Stat. § 269-6

[88] Haw. Rev. Stat. § 269-1

[89] Haw. Rev. Stat. § 269-16

[90] Haw. Rev. Stat. § 269-7

[91] Haw. Rev. Stat. § 269-92

[92] Haw. Rev. Stat. § 269-27.4

[93] Hawaii Ratepayer Protection Act. The act is currently undesignated in HRS § 269, but will be entitled "Performance incentive and penalty mechanisms." The act went into effect on July 1, 2018

[94] Haw. Rev. Stat. § 91 et seq.

[95] Haw. Admin. R. 6-61-1 et seq.

[96] Public utilities are defined to include electric utilities like the HECO companies and KIUC, but not to include renewable energy systems like IPPs or individual systems located on a customer's property. *See* Haw. Rev. Stat. § 269-1.

the authority to adopt rules pursuant to chapter 91 necessary for the purpose of this chapter.[97]

In addition to that general purpose, the Commission is also required to consider other regulatory impacts in the context of achieving the State's energy goals. These required considerations include the need to reduce the States' reliance on fossil fuels via energy efficiency and increased renewable energy generation, the costs and benefits of a diverse fossil fuel portfolio and maximizing the energy efficiency of all electric utility assets to lower and stabilize electricity costs, and whether implementation of a shared cost savings incentive mechanism, a renewable energy curtailment mitigation incentive mechanism, a stranded cost recovery mechanism, or differentiated authorized rates of return on common equity would be in the public interest.[98]

The power and duty to have general supervision over all public utilities is extremely broad and enables the PUC to justify nearly any action it takes, so long as a driving purpose behind that action is the protection of the public interest. The public interest refers to a balance of various interests affecting the public whom the Commission serves. This includes "long-term versus short-term needs, affordable rates versus efficient price signals, environmental values versus global competitiveness."[99]

Additionally, the term "public interest" in statutory language often creates a presumption that the Commission must also protect the public from the private interests of the utilities that may be at odds with the public at large, or the ratepayers. In short, protecting the public interest means assuring "universal, reliable, and safe service at reasonable rates."[100]

4.3.3.1.2 Definition of Public Utilities.

Under this statutory framework, public utilities are defined as including any entity "who may own, control, operate, or manage…any plant or equipment, or any part thereof… for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil."[101]

In short, the electric utilities in Hawaii, the HECO Companies and KIUC, meet this definition and are considered public utilities for the purposes of the statute. Notably, this definition explicitly

[97] Haw. Rev. Stat. § 269-6

[98] *Id.*

[99] Scott Hempling, Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction (American Bar Ass'n, 2013) at 3.

[100] *Id.*

[101] Haw. Rev. Stat.§ 269-1(1)

excludes those who own, control, operate or manage a renewable energy system on their own property, as well as those who sell energy generated on their own property to an electric utility.[102]

4.3.3.1.3 Regulation of Utility Rates; Ratemaking Procedure.

The PUC is specifically tasked and authorized to regulate the rates and ratemaking procedures for public utilities by HRS § 269-16. This notably includes ratemaking for electric utilities. Specifically, and in relevant part:

> *All rates, fares, charges, classifications, schedules, rates, rules, and practices made, charged, or observed by any public utility … shall be just and reasonable and shall be filed with the public utilities commission…. The commission, in its discretion and for good causes shown, may allow any rate, fare, charge, classification, schedule, rule, or practice to be established, abandoned modified, or departed upon notice less than that provided for in section 269-12(b)*.[103]

From the statute, it is clear that the PUC has broad power and discretion within the parameters of what is "just and reasonable" to regulate public utility rates and ratemaking processes. This is particularly relevant to the issue at hand regarding the regulatory capacity of the PUC, because the statute explicitly grants the Commission the authority to make any such changes.

4.3.3.1.4 Investigative Power

The PUC is vested with investigative power by HRS § 269-7, which states in relevant part, that the Commission and each Commissioner "shall have the power to examine into the condition of each public utility… the fares and rates charged by it … [and] its classifications, rules, regulations, practices, and service, and *all matters of every nature affecting the relations and transactions between it* and the public or persons or corporations."[104] Further, "*any investigation may be made by the commission on its own motion*, and shall [also] be made when requested by a public utility to be investigated, or by any person upon a sworn written complaint to the commission."[105]

This investigative power is a powerful tool that is used frequently by the Commission to look into various regulatory matters on its own accord, although often times the Commission will cite a legislative action or concern as an additional reason for the investigation.

4.3.3.1.5 Enforcement Power

---

[102] Haw. Rev. Stat. § 269-1(2)(M), (N).

[103] Haw. Rev. Stat. § 267-16(a), (b), emphasis added.

[104] Haw. Rev. Stat § 269-7(a), emphasis added.

[105] Haw. Rev. Stat § 269-7(c), emphasis added.

The PUC is also authorized by HRS § 269-15 to institute proceedings to enforce HRS Chapter 269. If the PUC believes that a public utility or person is "violating or neglecting to comply with any provision of this chapter or of any rule, regulation, order, or other requirement of the commission" it shall notify the utility or person who is in violation, and may begin proceedings as necessary to require the correction of the deficiency(s), and may also issue citations, as necessary.[106]

The power to enforce the existing rules and regulations of the PUC allows the PUC to more effectively carry out its own duties and obligations under the statute.

4.3.3.1.6 General Procedure

The Rules of Practice and Procedure Before the Public Utilities Commission are part of the Hawaii Administrative Rules ("HAR"), Chapter 61. These rules complement the HRS statutes and provide specific rules and guidelines for PUC practice and procedure to "secure the just, speedy, and inexpensive determination of every proceeding."[107] Examples of these rules include general provisions and requirements for proceedings before the Commission, agency hearing procedures, those for intervention and participation,[108] rate increase applications and tariff changes,[109] and Commission investigations, among others.[110]

The PUC also adheres to the rules outlined in HRS Chapter 91 on Administrative Procedure, which include the procedure and guidelines for rulemaking by agencies such as the PUC, and for contested case hearings.[111]

4.3.3.1.7 Select Codified Legislative Initiatives

The legislature can amend existing duties or add new responsibilities to the PUC.[112] Recently, the legislature has added additional requirements for the PUC to meet that further the state's energy and climate change mitigation and adaptation goals, including directives to change the regulatory process. Several are detailed herein.

---

[106] Haw. Rev. Stat. § 269-15(a).

[107] Haw. Admin. R. § 6-61-1 (current through 2018).

[108] Haw. Admin. R. § 6-61-55 through § 6-61-57 (current through 2018).

[109] Haw. Admin. R. § 6-61-85 through § 6-61-94 (current through 2018).

[110] *See generally,* Haw. Admin. R. chapter 61.

[111] See generally, Haw. Rev. Stat. § 91.

[112] Haw. Const., Art. III

4.3.3.1.7.1 State Renewable Energy Target

HRS § 269-92, Renewable Portfolio Standards, became law in 2015 and states that "each electric utility company that sells electricity for consumption in the State shall establish a renewable portfolio standard of: … one hundred percent of its net electricity sales by December 31, 2045."[113] Additionally, the PUC may "establish standards for each utility that prescribe what portion of the renewable portfolio standards shall be met by specific types of renewable energy resources,"[114] and can also monitor the utility companies' compliance with these standards, and impose penalties on delinquent utility companies following a hearing in accordance with HRS chapter 91.[115] In the case of situations that are beyond the electric utility company's reasonable control, including, for example, natural disasters or labor strikes, the Commission may use its discretion to waive penalties in part or in whole.[116]

The purpose of this statute is to:

> *update and extend Hawaii's clean energy initiative and renewable portfolio standards to ensure maximum long-term benefit to Hawaii's economy by setting a goal of one hundred percent renewable by 2045; provided that extending the [RPS] goals and transition to energy independence beyond 2030 shall be undertaken in a manner that benefits Hawaii's economy and all electric customers, maintains customer affordability, and does not induce renewable energy developers to artificially increase the price of renewable energy in Hawaii. This target will ensure that Hawaii moves beyond its dependence on imported fuels and continues to grow a local renewable energy industry*.[117]

This statute sets an overarching policy of reducing Hawaii's dependence on imported fossil fuel and growing the local renewable energy industry. It also provides clear goals and tasks for the PUC to follow (i.e., establishing standards and enforcing the law) as the PUC fulfils the obligations of this statute in particular, and as the PUC applies the statute to other regulatory actions. Indeed, the PUC has used this law as a basis for many of its actions since its passage, including most recently, its investigation of Performance-based regulation (detailed, *supra*), and in its interactions and requirements of the public utilities via rate-making procedures.

4.3.3.1.7.2 Community-Based Renewable Energy Tariff

---

[113] Haw. Rev. Stat. § 269-92(a).

[114] Haw. Rev. Stat. § 269-92(b).

[115] Haw. Rev. Stat. § 269-92(c).

[116] Haw. Rev. Stat. § 269-92(d).

[117] Hawaii Session Laws, Act 097, June 8, 2015 (H.B. 623 CD1, Relating to Renewable Standards), available at https://www.capitol.hawaii.gov/session2015/bills/HB623_CD1_.pdf.

HRS § 269-27.4, Community-based renewable energy ("CBRE") tariffs, became law in 2015 and requires each electric utility to file a proposed CBRE tariff or tariffs with the PUC by October 1, 2015. The PUC in turn and pursuant to HRS § 269-16, shall establish a CBRE tariff or tariffs, provided that such tariff(s) are found to be in the public interest.[118] CBRE tariffs are required to be approved by the Commission and must be tariff(s) that:

> *(1) Allow an electric utility customer to participate in an eligible renewable energy project that is providing electricity and electric grid services to the electric utility;*
> *(2) Allows the electric utility to implement a billing arrangement to compensate those customers for the electricity and electric grid services provided to the electric utility;*
> *(3) Is designed to provide fair compensation for electricity, electric grid services, and other benefits provided to or by the electric utility, participating ratepayers, and nonparticipating ratepayers; and*
> *(4) To the extent possible, standardizes and streamlines the related interconnection processes for community-based renewable energy projects.*[119]

In drafting the law, the legislature found that "it is in the public interest to promote broader participation in self-generation by Hawaii residents and businesses through the development of CBRE facilities in which participants are entitled to generate electricity and receive credit for that electricity on their bill. The legislature also found that CBRE stimulates the economy, reduces GHG emissions, promotes energy independence, and helps the state to meet its clean energy goals. Thus, the purpose of this law, as stated in the Act, is "to make the benefits of renewable energy generation more accessible to a greater number of Hawaii residents," and provides that the CBRE tariff "should, to the extent possible, be designed in an open and accessible process that should accommodate a variety of community based renewable energy projects, models and sizes."[120]

The PUC began this work in Docket 2015-0389, which is still open at the time of this writing.

4.3.3.1.7.3 Grid Modernization

HRS § 269-145.5, a statute on Advanced grid modernization technology and principles, came into effect in its current iteration on June 20, 2014 and requires the Commission to "consider the value of improving electrical generation, transmission, and distribution systems and infrastructure within the State through use of advanced grid modernization technology in order to improve the

---

118 Haw. Rev. Stat. § 269-27.4(a). The PUC's establishment of a CBRE tariff(s) can be based on a review of the proposed tariffs submitted by the utility companies. The PUC then may approve/establish that tariff as a CBRE tariff.

119 Haw. Rev. Stat. 269-27.4

120 Hawaii Session Laws, Act 100, June 10, 2015 (S.B. 1050 CD1, Relating to Energy (CBRE Tariffs)), available at https://www.capitol.hawaii.gov/session2015/bills/GM1200_.PDF.

overall reliability and operational efficiency of the Hawaii electric system."[121] The legislature also instructs the PUC to advance the public interest by balancing various considerations that are associated with such modernization of the electric grid. This includes enabling a diverse portfolio of renewable energy resources, expanding options for customers to manage their energy use, maximizing interconnection of distributed generation at just and reasonable rates while maintaining grid reliability, determining fair compensation for electric grid services to customers, and maintaining or enhancing grid reliability.[122] One of the purposes of the law was to accommodate increased DER and levels of renewable energy on the grid that would result from the efforts to comply with HCEI and to achieve RPS goals (although at this time, the goal was not yet at the level of 100% by 2045). Since the adoption of this law, the PUC has worked on several grid modernization projects, including those in Docket Nos. 2016-0087 and 2017-0226.

4.3.3.1.7.4 Performance-based Regulation (PBR)

The Hawaii Ratepayer Protection Act ("Act") was set forth by the Hawaii State Legislature in the 2018 session, was signed into law by Governor David Ige on April 24, 2018 as Act 005, and took effect on July 1, 2018.[123] The Act will be incorporated into the Hawaii Revised Statutes ("HRS") under Chapter 269, although official classification is pending.[124] The purpose of the act is "to protect consumers by proactively ensuring that the existing utility business and regulatory model will be updated for the twenty-first century by requiring that electric utility rates be considered just and reasonable only if the rates are derived from a Performance-based model for determining utility revenues."[125]

The Act requires the PUC to "establish performance incentives and penalty mechanisms that directly tie electric utility revenues to that utility's achievement on performance metrics and break the direct link between allowed revenues and investment levels. The performance incentives and penalty mechanisms, as may be amended by the public utilities Commission from time to time, shall apply to the regulation of electric utility rates under section 269-16" by January

[121] Haw. Rev. Stat. § 269-145.5(a).

[122] Haw. Rev. Stat. § 269-145.5(b).

[123] Hawaii Ratepayer Protection Act

[124] 2018 Legislative Session Undesignated Enactments, § 269 -. Performance incentive and penalty mechanisms. Eff. July 1, 2018

[125] Hawaii Ratepayer Protection Act, at 4.

1, 2020.[126] The Act also provides a list of regulatory impacts the PUC should consider in its design of such mechanisms.[127]

Shortly before this Act was signed into law, the PUC on its own initiative opened an investigative proceeding (as it is authorized to do under HRS § 269-7) to investigate PBR. Although it seems quite clear that the PUC was aware that the bill was moving through the legislature during this time, it highlights that the PUC had the authority to begin its investigation. Although it seems common for the PUC to start a new initiative once it has gathered public support or reasonably anticipates a mandate from the legislature, it is clear from the PUC's powers to regulate rates and the ratemaking procedure under 269-16 that the PUC does have the power to initiate such proceedings on its own. Most of the proposed regulatory models in this study are completely within the purview of the PUC to investigate, determine which will be most beneficial to the public interest, and implement. The exception to this general statement is the ISO model, which will be discussed in Section 5.4.5.

4.3.4 Independent Initiatives of the PUC: The Inclinations

The Inclinations are a white paper written by the Commission and included as an attachment to the decision and order to reject the HECO Companies Integrated Resource Plan ("IRP") proposal in 2014.[128] The Commission notes its authority to review and approve or reject the IRP according to HRS § 269-6(a) and to carry out investigations of the public utilities according to HRS § 269-7(a) and (c). Due to the Commission's decision that the HECO Companies "failed to articulate a sustainable business model in the intervening time since this directive [request for IRP] was set forth by the Commission almost one year [prior] in Order No. 31288,"[129] the Commission authored the white paper to set forth its perspective on the various business strategies and regulatory policy changes required to align the HECO companies' business model with customer interests and state policy goals.[130] Specifically, these include sections on Creating a 21st Century

[126] Hawaii Ratepayer Protection Act, at 5. Note that HRS § 269-16 is the primary statutory authority / mandate for the PUC to regulate utility rates and engage in ratemaking procedures, and sets forth the "just and reasonable" standard that the PUC must apply in its regulatory activities.

"All rates, fares, charges, classifications, schedules, rules and practices made, charged, or observed by any public utility or by two or more public utilities jointly shall be just and reasonable and shall be filed with the public utilities commission." HRS § 269-16(a).

[127] Hawaii Ratepayer Protection Act, at 5-6

[128] The Inclinations at 1.

[129] *Id.*

[130] *Id.*

Generation System, Create Modern Transmission and Distribution Grids, and enact Policy and Regulatory Reforms to Achieve Hawaii's Clean Energy Future.[131]

The inclinations are significant because they provide an example of the Commission acting without instruction from the legislature or any other institution. Although the paper does not ultimately set forth any legal requirements, it was used by the Commission in the recent months and years following its publication as a guideline that informed many of the Commission's activities and directives to the electric utilities.[132]

4.3.5 Legal considerations necessary for a transition to PBR

In the scenario in which Hawaii shifts from a COS regulatory framework to a PBR framework for the regulation of electric utilities, it is important to consider both the existing legal framework and whether any regulatory or legislative changes are required to implement the PBR regulatory model.

4.3.5.1 PUC Dockets Initiating and Regulating PIMs

The PUC has considered implementing various PIMs and even PBR prior to its most recent interest in PBR.[133] This section will discuss some of these PUC dockets, noting, in particular, the legal authority the PUC cites as enabling their actions, and whether the PUC initiated the docket independently, in response to external events, or out of obligation.

4.3.5.1.1 Docket 99-0396, Application of HECO companies for approval to implement PBR in their next respective rate cases.

In 1999, the HECO Companies filed an application to implement PBR in their next rate cases to the Commission under HRS sections 269-7 and 269-16. The HECO Companies proposed the use of an index-based price cap, an earnings sharing mechanism, and service quality mechanisms (SAIDI, SAIFI, percentage of call center calls during business hours answered within 30 seconds, and overall satisfaction in customer surveys with customers with recent transactions). The Commission did not approve this request, noting that COS regulation "has long been deemed

---

131 *Id.* at 3.

132 See e.g., the Hawaii Ratepayer Protection Act. Additionally, other orders citing the inclinations include In the Matter of Hawaiian Electric Company, Sept. 29, 2015 (the Inclinations as part of the consideration for transmission planning in regards to an application for approval to commit funds for a generating station project, at 33); as considerations in power purchase approvals (e.g., In the Matter of Hawaiian Electric Company, Inc., Docket No. 2014-0308, Decision & Order No. 33076); as consideration in the order instituting a proceeding to investigate integrated grid planning (in the matter of Public Utilities Commission, Docket No. 2018-0165, Order NO. 35569); as consideration when reviewing Power Supply Improvement Plans (e.g., In the Matter of Public Utilities Commission Instituting a Proceeding to Review the Power Supply Improvement Plans for [the HECO Companies], Docket No. 2014-0183, Order No. 34696.)

133 This interest includes the new Hawaii Ratepayer Protection Law, the PUC's investigation into PBR, and the commission of this study.

essential because the public utility industries were thought to be a natural monopoly."[134] Although the Commission declined to change from COS to PBR at that time, it explicitly did not preclude applicants from filing another PBR proposal in the future.[135] This docket and order represent an example of the PUC exercising its investigative and rate-making procedure authority to make a decision. This docket was brought by the HECO Companies and does not respond to nor satisfy any legislative mandate.

4.3.5.1.2 Docket 2008-0274, Investigation to Implement a Decoupling Mechanism

This docket was opened as an investigative proceeding to examine implementing a decoupling mechanism for the HECO Companies in 2008. The PUC was able to open this investigative document because of its authority to investigate under HRS 269-7. The investigation was brought in response to an Agreement between the State, Consumer Advocate, the Department of Commerce and Consumer Affairs, and the HECO companies to accelerate clean energy as a result of the creation of the Hawaii Clean Energy Initiative ("HCEI") – which is a partnership that began in 2008 between the State of Hawaii and the US Department of Energy.[136] In the final Decision and Order in this Docket, the PUC approved the decoupling mechanisms proposed (a Revenue Balancing Account ("RBA") and a Revenue Adjustment Mechanism ("RAM")) in the Joint Final Statement of Position by the HECO Companies and the Consumer Advocate, subject to some modifications. The mechanisms agreed to were intended to be consistent with the mechanism agreed to in the HCEI agreement.

In this situation, the PUC again used its investigative and regulatory authority to open the docket and perform its regulatory duties. This particular docket was opened as a direct result of an external state action – the creation of the HCEI.

4.3.5.1.3 Docket 2013-0141 Investigation to Reexamine the Existing Decoupling Mechanisms

This investigative docket to reexamine existing decoupling mechanisms (as approved in Docket No. 2008-0274) was implemented in 2013 and is still open as of August 2018. In the initial Order 31289, filed on May 31, 2013, "Instigating an Investigation to reexamine the Existing Decoupling Mechanisms," the Commission notes that its own concerns regarding the decoupling mechanisms "echo those expressed by the 2013 Hawaii State Legislature in connection with Senate Bill 120," which authorized the Commission to "establish a policy to implement economic incentives and cost recover regulatory mechanisms, as necessary and appropriate, to induce and accelerate electric utilities' cost reduction efforts, encourage greater utilization of renewable energy, accelerate the retirement of utility fossil fuel generation, and increase investments to

---

[134] Hawaii Public Utilities Commission, Order No. 18353, Docket No. 99-0396, issued Feb. 2, 2001

[135] *Id.* at 5-6.

[136] *See* Hawaii Public Utilities Commission, Final Decision and Order, Docket 2008-0274 issued Aug. 31, 2010, at 3.

modernize the State's electrical grids."[137] The Commission concluded that in light of that legislative guidance, and alongside its own concerns, it would examine whether potential economic incentives could be used to achieve reduced costs and improved customer rates and service.[138]

In Decision and Order 31908, the Commission ordered that in addition to revising the decoupling mechanisms, the HECO Companies would also be required to post tracking metrics online (reliability measures, generation availability, clean energy metrics and the cost of final delivered energy to customers by rate class).[139] This docket was not created in response to any request by the HECO Companies or to a legislative act. Rather, the Commission on its own accord initiated this investigation to examine whether the HECO Companies' decoupling measures from the Decision and Order in Docket 2008-0274 "effectively served their intended purposes, are fair to the HECO companies and the HECO companies' ratepayers, and are in the public interest."[140] The orders include as a guideline that "rates and charges of regulated public utilities in Hawaii must be reasonable, *and the commission has broad powers to investigate and examine the rates and practices of public utilities subject to its jurisdiction,"* citing for example of this authority, HRS sections 269-6, 269-7, and 269-16.[141]

In a later Order No. 32735 filed March 31, 2015, the Commission directed the HECO companies to make changes to their existing decoupling mechanisms[142] and considered whether the RAM was appropriate, whether PBR or other PIMs should be implemented, and whether specific measures to establish cost controls for baseline capital projects should be implemented.[143] Ultimately, this order established a cap on annual RAM adjustments and distinguished between PBR framework proposals and stand-alone PIMs without implementing either. Instead, the PUC provided a procedural schedule and directed the HECO companies to propose conventional standalone PIMs and identify appropriate steps for ECAC adjustments.[144] This order also referred again to Senate Bill 120 from the 2013 state legislature as legislative guidance for its consideration of performance metrics. Despite the existence of such legislative guidance, it seems that this was

---

137 Hawaii Public Utilities Commission, Order No. 31289, Docket No. 2013-0141, issued May 31, 2013, at 18-19.

138 *Id*. at 20.

139 Hawaii Public Utilities Commission, Decision and Order No. 31908, Docket No. 2013-0141, issued Feb. 7, 2014, at 70-77.

140 Order No. 31908 at 2.

141 Order No. 31908 at 9.

142 Hawaii Public Utilities Commission, Order No. 32735, Docket No. 2013-0141, issued March 31, 2015, at 2.

143 *Id.* at 15-16.

144 *Id.* at 38.

a supporting reason for the regulatory review rather than a primary one because it is included again as "guidance," rather than as part of the background information that set the context for this particular order.[145]

In Order 34514 of this docket, filed on April 27, 2017, the PUC established several backstop service quality PIMs (SAIDI, SAIFI, call center performance metrics), established guidelines for Major Project Interim Recovery, and directed the HECO companies to file tariff sheets for the established PIMs and revised RBA with an effective date of January 1, 2018.[146] This order also briefly references the same 2013 bill as referenced above, again as "legislative guidance."[147] Most recently, in order 35165 of this docket, the PUC directed the HECO companies to adopt the PIMs and RBA tariffs.[148]

4.3.5.1.4 Additional Proceedings Related to PIMs

In addition to the above detailed PIM dockets and resulting orders, the Commission has held (and in some cases, is still in the process of) other proceedings related to other PIMs or initiatives to increase renewable energy generation or update the grid to accommodate more renewable energy. These include proceedings on grid modernization,[149] procurement of utility-scale renewable energy generation,[150] and various other measures embedded in the utilities planning processes such as general rate cases and PSIP proceedings.[151]

---

145 *Id.*

146 Hawaii Public Utilities Commission, Order No. 34514, Docket No. 2013-0141, issued April 27, 2017.

147 *Id.* at 14.

148 Hawaii Public Utilities Commission, Order No. 35165, Docket No. 2013-0141, issued December 29, 2017.

149 Docket No. 2016-0087, Order No. 34436, Application for Approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project; Docket No. 2017-0226, Order No. 34773, Instituting a proceeding related to the HECO Companies' Grid Modernization Strategy (which adds to Docket No. 2016-0087).

150 Docket No. 2017-0352, Order No. 35405, Establishing a Performance Incentive Mechanism for Procurement in Phase 1 of the [HECO] Companies' Final Variable Requests for Proposals.

151 Note: Other dockets for further consideration (excluded in discussion above for brevity) include:
Grid Modernization: Docket No. 2016-0087, Order No. 34436 (Mar. 9, 2017), Application for Approval to commit funds in excess of $2,500,000 for the Smart Grid Foundation Project; Docket No. 2017-0226, opening docket Order No. 34773. Instituting a proceeding related to the HECO Companies' Grid Modernization Strategy (follows up to 2016-0087, opens a repository.
MPR – 3 yr. fixed cycle for general rate cases – no docket number
ECAC amendment possible in ongoing HECO general rate case. Docket no. 2016-0328, order no. 35372 filed Mar. 29, 2018 at 8.
HECO companies PSIP – Docket No. 2014-0183
PPAC purchased power adjustment clause see HRS 269-16.22

4.3.6 Conclusions on the Existing Legal Framework

Based on the information detailed above, it is clear that the PUC has wide-ranging and strong statutory authority to engage in the supervision and guidance of the states' electric utilities. Included in this authority is the power to investigate the utilities for any matter regarding its purpose to balance the interests of the companies and the customers. Additionally, the Commission has broad power to engage in ratemaking and ratemaking procedure regulations and oversight. The legislature may also add powers or responsibilities to the PUC and has done so. Examples of this include the legislature's addition of the 100% RPS requirement by 2045, the requirement to create a Community-Based Renewable Energy program, the requirement to create a grid modification plan, and most recently, the requirement to change the regulatory framework from COS to PBR, all of which fall to the PUC to implement. These newer laws provide the PUC with additional authority to regulate in specific ways or on specific topics.

In addition to the inclusion of this authority in the plain language of the statutes, the PUC's legal authority is expressed repeatedly through the Commission's regular activities in regulating the electric utilities. This report has detailed examples of the Commission acting both in response to external factors, such as a legislative mandate or applications of the utility companies, and several examples of the Commission acting independently of any other source. These examples are the reexamination of the decoupling mechanisms in Order 31908, where the Commission noticed the mechanisms were having an undesirable effect and acted upon it, and the *Commission's Inclinations*, which were written in response to the Commission's observation that the HECO Companies were not making the necessary plans to align with the state's energy goals. Notably, these inclinations were aligned with state energy goals.

4.4 Gaps in Existing Legal Framework and Required Changes

In terms of the PUC's authority or ability to enact any of the proposed regulatory changes examined in this report, it seems clear from the above discussion that the PUC has the authority to act as it sees fit to further its objectives within ratemaking and planning activities,[152] which include pursuing actions which accomplish state energy goals. In examples where the PUC initiated a regulatory proceeding or published a policy paper, it was because of the PUC's statutory authority, and also because the PUC observed a misalignment between the utilities' proposal(s) and the goals of the state or the public interest. In other instances, the PUC acted out of responsibility to fulfill a state statute or legislative act.

The proposed regulatory changes all involve some form of Performance-based regulation. The purpose of PBR is to disconnect the utilities' revenue from its cost of service and create incentives for the utility to undertake any number of initiatives which usually consist of increased renewable energy, modernized grids, and increased energy efficiency. Because PBR generally aligns the interests of the utility and the consumer, and often results in the overall modernization of the grid and increased generation and use of renewable energy, it seems clear that any PBR would be

---

[152] Note that this authority does not extend to creating new state agencies or other entities that may aid in achieving state energy goals, such as an IGO. This legal distinction is discussed in Section 5.4.5, infra.

aligned with pre-existing state energy goals and would be within the public interest. Therefore, PBR is something the PUC is authorized to consider or initiate in its regulatory capacity.

Despite the above conclusion, consideration of whether the PUC is able to act on its own to implement PBR is not necessary here because the State has already enacted a law requiring it. Therefore, in the same way that the PUC is working to implement other state laws that further state energy goals (such as the 100% RPS by 2045 target), it is required to do the same for PBR.

4.5 Conclusions on Overarching Legal Considerations for PBR

The Hawaii PUC has broad authority to regulate the public utilities in Hawaii and is specifically *required* to implement PBR. Due to this authority and legislative mandate, the PUC must implement some form of PBR that helps the state achieve its energy goals and is in the public interest.

Legal analyses for HERA and other elements of the Hybrid model will be considered in the relevant sections, below.

5 Distinctions Between Elements of the Proposed Regulatory Models

5.1 Outcomes-based PBR v. Conventional PBR

Although the previous sections provided an overarching assessment of the steps, timeline, costs, and legal requirements for PBR implementation, the models considered by this study differentiate between an Outcomes-based PBR model and a Conventional PBR model. This section of the report seeks to distinguish where differences in the costs, timeline, and legal requirements lie between both models.

5.1.1 Outcomes-based PBR

As discussed in previous working papers and Task 2.2.6 of this study, Outcomes-Based PBR is the most comprehensive PBR regime. It seeks to incentivize the utility toward beneficial outcomes for society. These potential outcomes include (i) enhance customer experience, (ii) improve utility performance, (iii) achieve public policies and goals, and (iv) healthy financial performance. Under this PBR regime, utilities have flexibility on preferred solutions and strategies to attain those outcomes. Other mechanisms such expanded performance incentive mechanisms ("PIMs"), earnings sharing mechanism ("ESM"), total expenditure ("totex") approach, and more stringent reporting regimes are included under the Outcomes-based PBR. The steps for implementing Outcomes-based PBR generally follow the overall steps that are used for PBR in general, or for Conventional PBR. However, due to the more intensive nature of Outcomes-based PBR, the Project Team anticipates that a switch to an Outcomes-based PBR model will involve more regulatory work, the repetition of some steps due to the inclusion of more program elements, and an overall longer timeline.

5.1.1.1 Overview of the Steps, Timeline, and Costs used to Implement the Outcomes-based PBR model

To determine the specific steps, timeline, and costs that Hawaii should anticipate as part of the implementation process for an Outcomes-based PBR model, the Project Team looked to the experience of the UK's transition to the RIIO model (Revenue = Incentives + Innovation + Outputs) for guidance. Such awareness of the potential or likely steps, timeline and costs may be particularly useful for Hawaii because of the differences in the timeline that was experienced in the UK and the timeline that is expected for Hawaii.

5.1.1.1.1 Steps and Timeline Currently Contemplated in Hawaii

If Hawaii were to implement an Outcomes-based PBR model, the PUC would still be required to meet the legislative deadline for PBR implementation by January 1, 2020. As discussed in Section 4.1.3 above, the PUC's current plan and schedule of proceedings appear to be aligned with this deadline, although it doesn't specify a particular PBR model for implementation.

In contrast, the implementation of the RIIO process in the UK took 30 months, which is significantly longer than the 21-month timeline currently contemplated in Hawaii. This timeline varied depending on the iteration (first iterations require more planning) and whether the utility companies were on the “fast-track” or not.[153] This 30-month timeline for RIIO does not include the 19 months used by the UK’s regulatory agency Ofgem to decide to change regulatory models and to develop the original design for RIIO, and the Project Team does not anticipate that Hawaii would have to replicate that lengthy design process. However, we also cannot assume some preliminary design time would not be necessary and note that such design time could cause some delay if it were actually needed.

It should also be noted that the timeline of the PBR implementation could be shorter than the timeline used in the UK because Hawaii uses far fewer utility companies than the UK does. Additionally, the Outcomes-based PBR timeline would depend on the mechanisms that the PUC decides to include in the first regulatory term. The greater the quantity and complexity of PBR mechanisms it wants to include, the longer the process would take. However, the Project Team does not expect a “fast track” mechanism to shorten the timeline required for implementing Outcomes-based PBR in Hawaii because use of such a mechanism is not feasible in Hawaii at this time.[154] The indicative timeline discussed in this memo applies to the Outcomes-based PBR that the Project Team proposed. The specific steps, timeline, and costs of the UK’s transition to RIIO are detailed below for consideration and comparison with Hawaii’s proposed plan.

5.1.1.1.2 Steps and Timeline Required for Transition to Outcomes-based PBR: UK’s RIIO Example

The UK’s regulatory agency, Ofgem, announced the decision to review its existing regulatory framework (Conventional PBR using an RPI-X formula) in March 2008. After some effort with research and development, in October 2010 Ofgem announced its intention to implement RIIO to regulate its electric and gas utilities. The first RIIO regulatory period began in 2013.

Following the decision to implement the RIIO model, the UK’s development and implementation of the actual RIIO plans required a timeline of approximately 30 months (or 2.5 years). The steps taken during the course of these 30 months was grouped by Ofgem into four “stages,” which are detailed in Figure 5, below:

Figure 5. Steps and Timeline to Implement RIIO in the UK

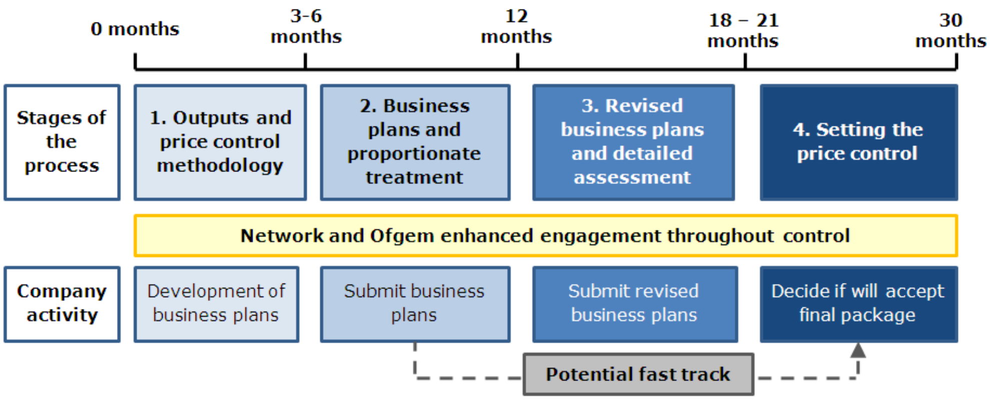
Stage	Task	Months
1.	Determine outputs and price control methodology; Stakeholder engagement	0 through 3-6
2.	Business Plan Development and Assessment	3-6 through 12

[153] Fast-track in RIIO discussed in Section 5.1.1.1.2, below.

[154] Fast-track is not feasible in Hawaii at this time because the process defined by the legislature and the PUC currently only contemplates a single process for PBR implementation, rather than multiple processes to be implemented in various situations. Changes to the PUC implementation process or new legislation requiring such changes could create an option for a fast track, but until that happens the Project Team finds that a Fast Track mechanism would not be used.

3.	Revise Business Plans and Detailed Assessment	12 through 18-21
4.	Set the Price Control	18-21 through 30

Figure 6. Ofgem diagram of RIIO implementation process



Source: Ofgem[155]

Although these four steps appear to be quite different from the 9 steps used in Alberta, the substance that comprises both sets of steps are broadly similar. Both begin with a decision to change the regulatory framework and continue to conduct research and analysis to determine the goals, methods, and outputs for the model and include robust stakeholder engagement during this process. Both then work with the utilities to develop plans for operating under PBR, arrive at a final decision, and continue to review and revise the model over time.

There are also key distinctions between the UK's Outcomes-based PBR implementation process and the implementation process for Conventional PBR. Outcomes-based PBR is a more complex scheme of regulatory mechanisms to be researched, designed, and implemented. Additionally, the RIIO model includes optimal business planning (according to the other desired outputs) as an incentive mechanism itself and provides a "fast track" for utility companies that comply with those outputs. More specifically, fast-tracked companies are those that submit business plans that meet various requirements, and consequently become eligible to quickly finalize all elements of their price control settlement with Ofgem, including drafting license changes. In contrast, companies that are not fast-tracked must spend additional time working with Ofgem to revise their business plans and go through additional detailed assessments and further scrutiny. Following the conclusion of their revision process, the non-fast-tracked companies are then able to finalize their price controls, although the additional review and revision processes can be time-consuming.[156]

---

[155] Ofgem, Handbook for Implementing the RIIO model, October 4, 2010 at 57.

[156] *Id.* at 10-11.

In Hawaii, the fast track that is used in the RIIO model would not be an option because the process issued by the PUC is singular and would not permit fast-tracking.[157] However, the issue of achieving Outcomes-based PBR in Hawaii in 21 months rather than a longer time period like the 33 months used in the UK could be addressed in other ways. The PUC might be able to complete the process within the relatively limited amount of time permitted by choosing PBR mechanisms that are not too complex and consequently would not require additional studies (e.g., productivity studies, etc.), and by taking care to work as efficiently as possible. The fact that the Hawaii market is significantly smaller with fewer utilities than the UK's could also result in the process requiring less time for completion. Therefore, while the PUC should be aware of the possibility of delay due to the complexity of the Outcomes-based PBR model and the length of time it took to implement RIIO in the UK, the PUC's target timeline appears to be feasible for implementation of Outcomes-based PBR if the process can be expedited as a result of the smaller market size, simpler mechanisms, and diligent and efficient work.

5.1.1.2 Transition Costs for Outcomes-based PBR

Due to the similarity between the overall regulatory work that must be done in a transition to a Outcomes-Based and Conventional PBR model, the Project Team determines that the cost estimates drawn from the conventional AUC example above are broadly appropriate for an Outcomes-Based model as well, though costs may be slightly higher for an Outcomes-Based model depending on the actual quantity and complexity of regulatory mechanisms being implemented.

5.1.1.3 Legal Requirements for Outcomes-based PBR

Based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals, as well as its explicit authority via recent legislation to implement PBR detailed in Section 4.3, above, it is clear that the PUC is authorized to implement PBR as it sees fit, including an Outcomes-based PBR model. Thus, there are no gaps in the legal framework to enable to PUC to enforce and regulate under an Outcomes-based PBR framework.

5.1.2 Conventional PBR

Conventional PBR is characterized by the use of a revenue cap using an indexing formula (e.g., inflation less productivity factor), a 3-year regulatory term, a totex approach, a symmetrical ESM, and continuing use of the performance incentive mechanisms already in place under the current PBR-Light / Cost of Service ("COS") regulatory regime as well as a slight expansion of them. These PIMs include those that regulate the availability and reliability of service, cost control, service quality, customer engagement, competitive procurement, and renewable portfolio standard ("RPS").

---

[157] Even if the PUC's schedule and plan could accommodate the fast track, the Project Team notes concern about whether it is even reasonable to expedite this process during the first generation of the PBR, since parties will need time to determine how the model works, how to work within it, etc.

In comparison with the Outcomes-based PBR model, Conventional PBR is based on inputs rather than outputs. Conventional PBR's revenue requirements or rates are increased by an indexation formula, which is the inflation less productivity factor. Utilities using Conventional PBR must provide their review requirements and justification for the costs in determining their rates. Other key features of Conventional PBR in relation to Outcomes-based PBR include the use of a shorter regulatory period (3 years instead of 5), a condensed list of PIMs, and fewer overall regulatory requirements.

5.1.2.1 Overview of the Steps, Timeline, and Cost used to Implement the Conventional PBR model

The steps, timeline, and cost to implement the Conventional PBR model can be represented by the example of Alberta's transition from COS to RPI-X. This analysis was included in Section 4.1, above. In sum, the Project Team concluded that in Alberta, Conventional PBR required approximately 33 months to implement, using a series of nine steps that encompassed the initial planning and research, shareholder engagement, additional studies, submission of PBR proposals by the utility companies and subsequent review, and finally implementation through the issuance of a decision. In its analysis of the steps and timeline used by the AUC to implement the Conventional PBR model, the Project Team noted that PUC would not necessarily follow the same steps as Alberta's in implementing the PBR. However, the Project Team also noted that awareness of this discrepancy may help the PUC in designing and implementing an efficient process that completes all the steps in a more efficient manner and within the 21-month timeline.

5.1.2.2 Transition Costs for Conventional PBR

The transition costs for Conventional PBR are also represented in the example of Alberta's transition from COS to RPI-X, included in Section 4.2, above. In summary, the Project Team's calculations show that operating expenses increased by approximately 10.9% during the transition phase to Conventional PBR and that costs decreased to pre-transition levels following the transition.

5.1.2.3 Legal Requirements for Conventional PBR

The PUC is authorized to implement PBR as it sees fit, including a Conventional PBR model. This is based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals, as well as its explicit authority via recent legislation to implement PBR detailed in section 4.3, above. Thus, there are no gaps in the legal framework to enable to PUC to implement and regulate under a Conventional PBR framework.

5.1.3 Summary of Distinctions Between Outcomes-Based and Conventional PBR

Based on the analyses included in Sections 4.1, 4.2, 4.3, and 5.1, above, it is clear that Outcomes-based PBR is more robust and complex than Conventional PBR, but despite that difference, the general steps to implement either PBR model are quite similar, as are the baseline costs.

In comparison with Conventional PBR, Outcomes-based PBR requires a longer period of research and design and potentially can require more extended time periods during which to engage with the utility companies in developing PBR compliant business plans. Both models utilize periods of research and design, stakeholder engagement, and subsequent design modification, require the issuance of a final PBR model (which includes the various PBR mechanisms), engagement with stakeholders and the utility companies to operate under the chosen PBR model, and continued review and revision. The Project Team anticipates the financial impact on the PUC of implementing either PBR model will be an increase in operating expenses by about 10.9% during the transition, and a return to ordinary expense amounts following implementation. The Project Team also notes that Outcomes-based PBR could also render a higher cost due to the greater number of and complexity of PBR mechanisms within the model. Finally, the PUC is legally authorized to implement either PBR model.

5.2 Light HERA

The Hawaii Electricity Reliability Authority ("HERA") was envisioned by the 2012 Hawaii State Legislature as an entity that would support the Commission in the regulation and oversight of the reliability and accessibility of Hawaii's electricity systems. The legislature viewed reliability oversight and regulation as necessary to ensure that all types of generation resources (and especially renewable energy sources) could be integrated into the grid without compromising reliability.[158] Specifically, the purpose of HERA's enabling act was to:

> *[A]uthorize the public utilities commission to perform necessary electric system reliability and grid access oversight functions, and to allow the commission to contract for the services of a Hawaii electricity reliability administrator to support the commission in carrying out those critical functions throughout the state.*[159]

5.2.1 Statutory Definition and Authority of HERA

The 2012 Hawaii Legislative Act 166 regarding the reliability of the Hawaii electric system is codified in the Hawaii Revised Statutes ("HRS") under chapter 269, section 141 et seq. Under these statutes, the PUC has jurisdiction over matters concerning interconnection requirements and interconnections within the state.[160] This includes the authority to:

---

[158] Hawaii Session Laws, Act 166, June 27, 2012 (S.B. 2787 CD1, Relating to Electricity), available at: https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm .

[159] *Id.*

[160] Haw. Rev. Stat. § 269-142(c). The Hawaii electric system is defined as "all electric elements located within the State together with all interconnections located within the state that collectively provide for the generation, transmission, distribution, storage, regulation, or physical control of electricity over a geographic area; provided that this term shall not include any electric element operating without any interconnection to any other electric element located within the state." Haw. Rev. Stat. § 269-141

- adopt, by rule or order, reliability standards and interconnection requirements that would apply to any electric utility and any user, owner, or operator of the Hawaii electric system;[161]

- monitor the reliability and operation of the Hawaii electric system using any data necessary to ensure the reliable operation of the Hawaii electric system, and to compel the production of any such data;[162]

- take all necessary steps (including the imposition of reasonable penalties and adoption of rules) to ensure that any electric utility or other entity that uses or connects to the Hawaii electric system complies with all adopted reliability standards and interconnection requirements;[163] and

- make determinations regarding any disputes related to interconnection.[164] The PUC is also required to consider the value of modernizing the grid while balancing a variety of public interests.[165]

With specific regard to HERA, the statute provides that

> *the commission may contract for the performance of its functions under this part with a person, business, or organization, except for a public utility as defined under this chapter, that will serve as the Hawaii electricity reliability administrator … provided that the commission shall not contract for the performance of its functions under 269-142(a) and (b) [to adopt by rule or order, or develop as necessary or by recommendation, reliability standards and interconnection requirements] and 269-146 [to create a Hawaii electric reliability surcharge].*[166]

In other words, under this law, the PUC may contract with a qualified third party to delegate these duties, but still retains full authority over HERA and retains the exclusive authority to adopt or develop reliability standards and interconnection requirements.[167] In addition, the entity selected to serve as HERA shall satisfy whatever qualifications are established by the Commission by rule or order, and maintain reasonable and necessary staffing to offer "prudent and reasonable

---

161 Haw. Rev. Stat. § 269-142(a).

162 Haw. Rev. Stat. § 269-143.

163 Haw. Rev. Stat. § 269-144.

164 Haw. Rev. Stat. § 269-145.

165 Haw. Rev. Stat. § 269-145.5.

166 Haw. Rev. Stat. § 269-147(a).

167 Haw. Rev. Stat. § 269-147(b).

recommendations on the development of reliability standards and interconnection requirements," to provide adequate technical ability to properly monitor operations of the Hawaii electric system, and to possess an appropriate level of impartiality for reviewing matters concerning interconnection.[168]

As discussed in the previous working papers, the statute also provides a funding mechanism for HERA operations. Under section 269-146, the PUC "may require, by rule or order, that all utilities, persons, business, or entities connecting to the Hawaii electric system… shall pay a surcharge that shall be collected by Hawaii's electric utilities... Amounts collected through the Hawaii electricity reliability surcharge shall be transferred in whole or in part to any entity contracted by the Commission to act as [HERA]," and these funds shall be used "for the purposes of ensuring the reliable operation of the Hawaii electric system and overseeing grid access on the Hawaii electric system through the activities of HERA."[169]

These funds are to be used only to carry out the operations of HERA, which include "administrative, technical, or other related requirements for effectively ensuring the reliability of the Hawaii electric system,"[170] and will not be available to satisfy any other current or past obligations of the State.[171] Additionally, HERA will be responsible for submitting a status and financial report to the PUC each year following the date of initial contracting.[172]

5.2.2 Current Status of HERA

While having legislative authority to create HERA, the PUC has not yet done so and is not required to.[173] From the available record, it appears that the PUC was in the process of considering reliability standards for the electric utilities prior to the enactment of the HERA law. In response to a 2009 decision and order approving a Feed-in Tariff ("FIT"), in which the Commission found that "reliability constraints exist and could affect the amount, type, and location of renewable energy that can be incorporated into the HECO Companies' systems without compromising

[168] Haw. Rev. Stat. § 269-148.

[169] Haw. Rev. Stat. § 269-146.

[170] Haw. Rev. Stat. § 269-149.

[171] *Id*.

[172] *Id*.

[173] Note that according to the HERA statute, "the commission *may* develop reliability standards and interconnection requirements as it determines is necessary or upon recommendation from any entity, including an entity contracted by the commission to serve as the Hawaii electric reliability administrator under this part." HRS § 269-142, emphasis added. Note also, "the commission *may* contract for the performance of its functions under this part with a person, business, or organization… that will serve as the Hawaii electricity reliability administrator provided for under this part…"HRS § 269-147, emphasis added.

reliability,"[174] the Commission opened another docket on September 8, 2011 to "Institut[e] a Proceeding to Investigate the Implementation of Reliability Standards for [the HECO Companies]."[175] As a result of this docket, a Reliability Standards Working Group ("RSWG") was created and conducted collaborative work over a period of 19 months.[176] The primary purpose of the RSWG was to "recommend an appropriate set of reliability standards, metrics, rules, and criteria to 'help determine how [to] interconnect the maximum amount of renewable generation to the grid while preserving grid reliability,' consistent with Hawaii's clean energy statutory mandates and policies."[177] The RSWG's final report was filed with the PUC on October 18, 2012, with reliability standards recommendations for the PUC to consider for adoption.[178] In addition to providing detailed information and recommendations for reliability standards for PUC consideration, the RSWG also provided insight on its perception of the role of HERA. Specifically, the RSWG listed that HERA:

> a. *Shall monitor the "day-to-day" standards activities, including proposing specific standards, and implementation, administration and enforcement policies and procedures*
> b. *Shall oversee the activities of the Standards Development Board/Committee and/or sub-committees*
> c. *Shall establish the eligibility criteria for membership on the Standards Development Board/Committee*
> d. *Shall select and/or remove members from the Board/Committee*
> e. *Shall have an employee(s) or representative(s) on the Board/Committee*
> f. *Shall prepare implementation policies and procedures, including, but not limited to, administration, enforcement, compliance oversight, and establishment of penalties and assessment thereof for review and approval by the PUC*
> g. *Shall implement and enforce all approved standards, policies and procedures*[179]

---

[174] Hawaii Public Utilities Commission, Decision and Order, Docket No. 2008-0273, issued Sept. 25 2009, at 49.

[175] Hawaii Public Utilities Commission, Order Opening Docket, Docket No. 2011-0206, issued Sept. 8, 2011.

[176] Note: the members of the RSWG consisted of many of the frequent parties to other electric utility-related dockets, such as the utilities (HECO, HELCO, MECO, and KIUC), state counties, state agencies (DCCA, DCA, DBEDT), Generators and advocates, and environmental advocates. Hawaii Public Utilities Commission, Order No. 30694 (RSWG Final Report), Docket No. 2011-0206, issued Oct. 18, 2012, at 5 (hereinafter "RSWG Final Report").

[177] RSWG Final Report at 220 (RSDG Appendix D-1 – Potential Framework for Development and Implementation of Electric Utility Reliability Standards in Hawaii).

[178] RSWG Final Report at 101.

[179] *Id.* at 225. Notably, the Standards Development Board/Committee is responsible for the identification, review, and approval of standards for drafting. Id.

Additionally, the RSWG proposed that HERA would consider and adopt the various reliability standards that were developed in the final report, and then submit the standard or other information to the PUC for approval.[180]

The RSWG also proposed the creation of a Registered Ballot Body who would be registered with HERA and vote on reliability standards, a Ballot Pool comprised of members of the Registered Ballot Body who would respond to pre-ballot requests to participate in a particular standard action, and a Standards Board/Committee who would serve at the direction of HERA to manage the standards processes for development of reliability standards and associated information in accordance with the information and procedures laid out in the RSWG's final report.[181] The RSWG also noted that HERA could form technical committees, subcommittees, working groups, and task forces to conduct technical research, as needed, and recommended the creation, through HERA and the Standards Board/Committee, of drafting teams comprised of industry experts to refine the information and recommendations contained in the RSWG final report.[182]

In 2014, the PUC issued its ruling on the RSWG work product, which included comments on HERA.[183] The PUC noted that the RSWG's work product was closely linked to HERA and the reliability standards developed by the Reliability Standards Development Group ("RSDG") (included within the RSWG final report) would likely transfer to HERA for implementation once approved. However, citing its "broad authority and discretion granted" by the HERA law, the PUC "decided to initiate its own framework addressing the purpose, scope, organizational structure of HERA ('HERA Framework'), which is under development."[184]

Notably, the Commission also stated its intent to open a new HERA docket and "propose the HERA Framework in that proceeding as a starting point to establish the issues for the docket and receive stakeholder input" via the opportunity to intervene or participate in the new HERA docket as provided by the Commission's rules of practice and procedure.[185] During the time that the HERA docket would be developed and proceed, the PUC intended to serve as HERA, until the official entity was formally established.[186]

---

180 *Id*. at 228

181 *Id*.

182 *Id*. at 229.

183 Hawaii Public Utilities Commission, Order No. 32053 (Ruling on RSWG Work Product), Docket No. 2011-0206, issued April 28, 2014, at 111 (hereinafter "Ruling on RSWG Work Product").

184 Ruling on RSWG Work Product at 112

185 *Id*.

186 *Id*. at 112-13.

The intent to open a HERA docket was also mentioned as recently as the Commission's annual report for FY 2014.[187] However, HERA was not the subject of any new dockets following the 2014 order, nor was it mentioned in subsequent annual reports. A possible explanation for this shift away from a highly researched, desired and authorized PUC process to create HERA may possibly be explained by the HECO Companies' proposed merger with NextEra that was announced in December 2014.[188] For example, in the PUC's 2015 annual report, Docket 2015-0022 regarding the HECO Companies and NextEra Energy Transfer / Merger was listed first in a short list of top priority dockets.[189] In its 2016 annual report, the PUC stated that

> *[t]he application for approval of the transfer of control of the Hawaiian Electric Companies to NextEra Energy required significant staff resources. After a 20-month review of more than 88,000 pages of filed documents, 22 days of formal evidentiary hearings, and seven public listening sessions on each of the main Hawaiian Islands, the Commission dismissed the application in a 2-0 decision shortly after the close of the fiscal year.*[190]

The report then listed the other energy-related dockets the Commission made progress on that year.[191] Regardless of the reason for the pause in the PUC's work on HERA, it is clear that the PUC is authorized to create HERA, and that it previously intended to open a docket specifically for this purpose.[192]

5.2.3 Steps and Timeline Approach

Because the process to create HERA is already underway, this study's approach to evaluating the steps and timeline necessary to implement HERA begins where the current process concluded. More specifically, this study does not contemplate the steps required to authorize the creation of the entity because such legislation has already been enacted. Because the PUC has already stated its intent to open a docket prior to and in order to create HERA, this study simply examines the

---

187 PUC Annual Report FY 2014 at 35. "The commission stated its intent to commence a new docket to evaluate and approve proposed reliability standards and that existing periodic electric reliability reporting will be expanded and consolidated to provide greater transparency of reliability performance related information."

188 NextEra Energy, "NextEra Energy and Hawaiian Electric Industries to Combine," December 3, 2015, http://www.nexteraenergy.com/news/contents/2014/120314.shtml. The transaction was valued at approximately $4.3 billion and would have been one of the largest business deals in the state's history.

189 PUC Annual Report FY 2015 at 9.

190 PUC Annual Report FY 2016, executive summary at 1 (p. 3/83)

191 *Id*.

192 It is also important to note that the PUC is not required to implement HERA, nor is bound by its prior work on HERA. The statutory language uses the word "may" which grants authority without creating requirements, and there is nothing in the existing PUC work on HERA to suggest that the PUC is bound to its past work. However, it seems reasonable that the PUC would likely base future HERA work on previous HERA work, for the sake of efficiency.

typical Hawaii PUC investigative docket process for guidance on the steps and timeline necessary to implement HERA should it choose to do so.

5.2.4 Steps and Timeline Necessary to Implement HERA

As was stated above, the PUC is statutorily authorized to create HERA, received detailed information and suggestions for the development, organization, and responsibilities of HERA from the PUC-created RSWG, and had planned to open a HERA docket so that additional stakeholders like IPPs could participate in the creation of the HERA entity. During this preliminary development process, the PUC agreed to act as HERA until the entity is created. If the PUC were to pick up the process again, the Project Team anticipates that it would start by opening an investigative docket. The proceedings in PUC investigative dockets inevitably vary from docket to docket. Overall, common or consistent elements are detailed below. The average time for completion of a similar docket is around 2 years, although some take years longer, depending on the specific issue(s) at hand.

Figure 7. Steps and Timeline to Implement HERA

Summary of HERA Steps and Timeline	Action	Month
Step 1.	Open Investigative Docket	1
Step 2.	Initial Proceedings (Motions to intervene, motions to grant or deny intervention)	Month 1-18, 1-24
Step 3.	Issue Decision and Order regarding Conclusions on the Docket	Month 18-24
Step 4.	Address Outstanding Issues outlined in the Decision and Order (optional)	Months 18-24+
Step 5.	Create HERA according to the Decision and Order	Months 18-24
Step 6.	Review and Adjust HERA as necessary	Month 36 +

5.2.4.1 Step 1. Open an Investigative Docket

Under HRS § 269-7, the PUC is authorized to open investigative dockets and does so when it initiates its consideration of an issue on its own (or in response to a request for investigation, or a legislative initiative directing the PUC to act)[193] rather than in response to an application from a utility.[194] At a minimum, the initial document usually contains background information and context for the investigation, states the relevant authority, states any named parties and procedural matters, and orders (including one order to initiate the investigative proceeding).

5.2.4.2 Step 2. Carry out proceedings of the investigative docket

Following the opening of the docket, interested stakeholders may apply to the Commission to become intervenors who are able to interact in the docket process. Motions to file for intervention are required to be served on all parties "no later than twenty days after the commission orders an investigation."[195]

Following the submission of these motions, the PUC will issue an order granting or denying intervention to the parties if the parties are determined to be sufficiently interested and do not unreasonably broaden the issues presented.[196] Although the PUC's response time may vary depending on the volume of motions for intervention they may receive for a particular document, it often takes the PUC several weeks to respond and issue an order granting or denying intervention to applicants.

Other proceedings can include, for example, requests for and issuances of protective orders, extensions, or additional information, the provision by the PUC of additional guidance or clarity on a particular issue or procedural matter, or submission of status reports or other work product (for example, the final report of the RSWG in Docket No. 2011-0206).

5.2.4.3 Step 3. Issue an order that details the PUC's conclusions based on the proceedings in the Investigative Docket

Once all the necessary information has been submitted to the Commission, the proceeding may be decided.[197] This typically results in a Decision and Order issued by the PUC, wherein the PUC

---

[193] See e.g., Docket 2008-0273, Instituting a Proceeding to Investigate the Implementation of Feed-In Tariffs (filed Oct. 24, 2008 based on agreements between the HECO Companies and the Consumer Advocate, and the PUC's determination that such an investigation was appropriate); Docket 2008-0274, Instituting a Proceeding to Investigate Implementing a Decoupling Mechanism for [HECO Companies] (Oct. 24, 2014, also in response to agreements between HECO companies and the CA, as well as the PUC's determination that an investigation was appropriate); Docket No. 2010-0037, Instituting a Proceeding to Investigate Establishing Energy Efficiency Portfolio Standards, Pursuant to Act 155, Session Laws of Hawaii 2009 and Hawaii Revised Statutes § 269-96 (Mar. 8, 2010).

[194] For contrast, see Docket 2015-0389, Application for Approval to Establish a Rule to Implement a Community-Based Renewable Energy Program, and other related matters. (Filed Oct. 1, 2015 in response to 2015 Act 100, which required the utilities to file proposed community-based renewable energy (CBRE) tariffs with the PUC.)

[195] Haw. Admin. Rules § 6-61-57.

[196] Haw. Admin Rules § 6-61-55.

[197] Haw. Admin Rules § 6-61-119.

will discuss the issues and information brought forth during the proceedings and issue an order(s), usually related to the purpose of the docket. The substantive decision and order is often a lengthy document that is the result of careful thought and consideration by the PUC. In many cases, it can take around 12 – 24 months to issue the decision and order from when the docket is opened. For example, in Docket 2011-0206 regarding the Reliability Standards Working Group, the PUC ruling on the RSWG work product was issued on April 28, 2014, 13 months after the RSWG's Independent Facilitator ("IF") issued her final report, which included the voluminous work product of the RSWG,[198] and more than two years since the docket was opened on September 8, 2011.[199] In Docket 2010-0037 the docket was opened on March 8, 2010, and the Decision and Order approving a framework for energy efficiency portfolio standards was issued nearly 20 months later on January 3, 2012.[200]

5.2.4.4 Step 4. Address any outstanding issues directed by the Decision and Order

In some cases, a substantive Decision and Order does not conclude the docket. In these cases, the Decision and Order may request additional information from a party or parties before it is able to make its conclusions and close the docket. For example, in Docket 2010-0037, the January 3, 2012 Decision and Order approves the framework for energy efficiency but provides that "more specific direction and/or guidance related to the implementation of the principles addressed herein will be provided in future orders."[201] Indeed, subsequent Decisions and Orders in the docket relate to the creation of an Energy Efficiency Portfolio Standards Technical Working Group. Once the group began meeting on its own, and the elements of the procedural schedule for the docket were all met, the docket was formally closed in Order 30300 on April 4, 2012.

5.2.4.5 Step 5. Create HERA according to the Order

For the creation of HERA, once there is specific guidance provided through decisions and orders from the PUC (that will be informed by the participation of various intervenors who will likely include the members of the RSWG as well as IPPs), the PUC should work to contract with an appropriate entity to overtake the reliability and interconnection oversight responsibilities currently entrusted to the PUC and formally become HERA.

5.2.4.6 Step 6. Review and Adjust

Following the creation of a contracted HERA entity, the PUC will continue to oversee HERA. This is supported by the requirement that HERA submit annual reports of HERA's progress and

---

198 See Hawaii Public Utilities Commission, Docket 2011-0206., available at: https://dms.puc.hawaii.gov/dms/index.jsp,

199 *Id*.

200 See Hawaii Public Utilities Commission, Docket No. 2010-0037, available at: https://dms.puc.hawaii.gov/dms/index.jsp.

201 Hawaii Public Utilities Commission, Decision and Order No. 30089 (Approving a Framework for Energy Efficiency Portfolio Standards), Docket 2010-0037, issued Jan. 3, 2012, at 14.

financial status.[202] Using this information and its authority to manage HERA, the PUC will monitor and make adjustments to HERA's duties and responsibilities as necessary.

5.2.5 Transition Costs of HERA

As has been stated elsewhere in the report, Hawaii can learn from the experiences of other jurisdictions in considering the transition to different regulatory models. In terms of the shift to HERA, this study has noted that legal authority for HERA already exists, that a PUC-authorized reliability provided suggestions on how the entity should operate, and that following the release of that study, the PUC stated that despite the recommendations in the study, the PUC would open its own HERA docket to determine the details regarding its implementation and operation. Although it is difficult to estimate the cost of implementing HERA via the docket process because public documents exclude those specific cost allocations, it is possible to estimate the expected start-up and operational costs by comparing HERA with similar bodies in other jurisdictions.

5.2.5.1 Cost Calculation Approach for HERA

To estimate the transition and operating costs of HERA,[203] the Project Team adopted the approach of scaling costs from similar mainland organizations based on the cost-per-kWh of system sales. While such a benchmarking-based approach is generally suitable for estimating costs of new organizations, Hawaii's relatively small electric grid does present complications, as a simple per-kWh scaling approach may overestimate the degree to which fixed organizational costs may be scaled to smaller jurisdictions (and therefore underestimate costs). To account for this, the Project Team has included a range of costs that account for a more conservative approach to cost scaling.

To estimate the operational costs of HERA, the Project Team used the costs of the North American Electric Reliability Corporation ("NERC") for comparison, due to the similarities between the two entities. NERC is a non-profit organization that was certified by the Federal Energy Regulatory Commission ("FERC") as its Electric Reliability Organization ("ERO").[204] The Federal Power Act ("FPA") required FERC to certify an ERO to develop mandatory and enforceable Reliability

---

[202] Haw. Rev. Stat. § 269-149(b)

[203] The overall cost of HERA will likely be paid by all those who connect to the Hawaii electric grid through the surcharge that the HERA law authorizes the PUC to charge for all the operational costs (including administrative, technological, and other requirements of HERA). See Haw. Rev. Stat. §§ 269-146, 149. See also Section 5.2.1, Statutory Definition and Authority of HERA, *supra*.

[204] North American Electric Reliability Corp., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

See also, 157 FERC ¶ 61,043 at 1. "Section 215 of the Federal Power Act (FPA) requires the commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. In July 2006, the Commission certified NERC as the ERO."

Standards, subject to Commission review and approval.[205] NERC is also funded equitably by its end users throughout its jurisdiction.[206]

The Project Team looked to NERC's annual funding requirements and scaled the costs to the size of Hawaii's electric system. The Project Team acknowledges that this methodology has two shortcomings. First, the specific duties and areas of responsibility of HERA may not match those of NERC precisely, which could lead to inaccuracies in projecting the costs of HERA based on those of NERC. Second, directly scaling the costs of NERC (which manages a jurisdiction encompassing the contiguous United States, most of Canada, and a portion of Baja California in Mexico) to an entity responsible for the much smaller jurisdiction of Hawaii would ignore economies of scale in operating costs and may underestimate the costs of HERA. However, in the absence of better information on potential HERA operating costs, the team has relied on this methodology in this analysis.

The Project Team based HERA transition costs on the start-up costs of the Reliability Entity set up in the State of Texas (part of the Electric Reliability Council of Texas), which were available from a FERC report on the start-up and operational costs of Regional Transmission Organizations.[207]

As noted above, the team used a conservative scaling factor to account for the smaller size of Hawaii's electric grid than these reference cases. A scaling factor of 250% was drawn from the same FERC report as above (which provides estimated $/kWh impacts for RTOs serving both typical and small jurisdictions).[208]

5.2.5.2 Annual Funding Requirement of NERC at the federal level

NERC is required to submit budget proposals to FERC each year for review, comment, and approval. NERC states that its business plan and budgets are based on the following program areas that were originally listed in their application to become an ERO:

> *(1) Reliability Standards; (2) Compliance Monitoring and Enforcement Program and Organization Registration and Certification; (3) Reliability Assessment and System Analysis; (4) Performance Analysis; (5) Reliability Risk Management, which is comprised*

---

[205] 16 U.S.C. § 824o (2012).

[206] 15 FERC ¶ 61,043 at 6, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets (issued Oct. 20, 2016)

[207] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004.

[208] However, FERC's reference case for a small RTO market is its Desert Southwest region combining Arizona, Colorado, and New Mexico, with combined annual electric sales at of the time of 127 TWh/year. This is still approximately 10 times higher than the Project Team's Hawaii load forecast of 11.9 TWh/year.

of Situation Awareness and Event Analysis; (6) Electricity Information Sharing and Analysis Center; and (7) Training, Education, and Operator Certification.[209]

Since its designation as the ERO, NERC's annual net funding requirement for its United States operations has gradually increased overall, with some exceptions due to fluctuations in penalty payments. In 2016, NERC's net funding requirement (to be allocated in 2017) was approximately $155 million (including funding for regional bodies). Within the United States, NERC's costs are allocated to end users at a proportional per-kWh rate, which in 2016 was calculated as $0.0000389 per kWh (or $0.0000405 inflated to 2018 dollars).[210]

5.2.5.3 Reliability Organization Start-Up Costs

The Project Team used the start-up costs of ERCOT's Reliability Authority as the basis for the transition costs to the HERA model. In 2002, the start-up cost of this entity was $4.5 million ($6.4 million in 2018 dollars).[211]

5.2.5.4 Estimate of Operational costs of HERA in Hawaii

While the costs of NERC and ERCOT's Reliability Authority provide reasonable comparators to a HERA entity in Hawaii, there are several sources of uncertainty in any resulting cost estimate. First, at this stage in HERA's development, it is difficult to know if its program areas will align directly with those of reference organizations. As noted above, scaling the costs of NERC, which is active in all 48 contiguous states, and ERCOT's Reliability Authority to Hawaii introduces a source of error given the much smaller size of Hawaii's electric grid.

Scaling the per-kWh start-up costs of ERCOT's Reliability Authority and the operating costs of NERC directly to Hawaii's electricity sales yields a start-up cost (in 2018 dollars) of $234,000 and an annual operating cost of $483,000. To obtain a more conservative estimate that reflects Hawaii's smaller size, the Project Team applied FERC's 250% cost factor for small jurisdictions, yielding a start-up cost of $585,000 and an annual operating cost of $1.2 million. These costs are summarized in **Error! Reference source not found.** below.

Figure 8. Estimated HERA Transition and Annual Operating Costs

Figure 8. Estimated HERA Transition and Annual Operating Costs

---

[209] 15 FERC ¶ 61,043 at 4, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets (issued Oct. 20, 2016)

[210] 157 FERC ¶ 61,043, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets, issued October 20, 2016, available at: https://www.ferc.gov/whats-new/comm-meet/2016/102016/E-5.pdf at 3.

[211] FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004.

Estimate	Transition Costs	Annual Operating Costs
Direct Scaling	$234,000	$483,000
Conservative Scaling	$585,000	$1,208,000

Relative to Hawaii PUC expenditures, estimated HERA costs are quite low. For example, in 2016, the PUC had Special Fund Revenues from Public Utility Fees that totaled $20.6 million ($21.5 million in 2018 dollars).[212] Based on the above calculation, HERA's funding need would be approximately 2% of that of the PUC under the direct scaling approach, and 6% under the conservative scaling approach. As noted above, it is possible that a more aggressive scaling factor is warranted given Hawaii's small size, in which case HERA costs would exceed these estimates.

5.2.6 Conclusions on Steps and Associated Costs for Conventional PBR + Light HERA Model

The transition from a COS to a PBR regulatory framework is one that will require a significant regulatory effort. These steps include making the decision to implement PBR, conducting extensive research and analysis to determine the appropriate PBR mechanism, setting in place data collection methods, conducting extensive stakeholder outreach (particularly with the utilities), evaluating PBR proposals, and issuing PBR decisions. The PUC is on a 21-month timeline from the state legislature, which is a shorter period of time to complete the steps used for either the Outcomes-based or Conventional PBR models, which have taken up to 30 and 33 months to complete in other jurisdictions, respectively. However, the Project Team anticipates that Hawaii may benefit from prior efforts and implemented PBR on a more efficient timeline (particularly if it is able to avoid several sources of delay that impacted timelines in Alberta and the UK). Hawaii has already published a schedule for implementing PBR that extends about 12 months from the initial Decision and Order initiating an investigation on PBR, and the steps already planned track closely with those used in Alberta.

5.2.7 Legal Considerations for HERA

Based on the PUC's broad statutory authority to engage in the supervision, guidance, and regulation of Hawaii's public utilities according to the public interest and to further the State's energy goals detailed in Section 4.3, as well as its explicit authority via recent legislation to implement HERA detailed in Section 5.2.1, above, it is clear that the PUC is authorized to open a HERA docket and to implement HERA as it sees fit. Thus, there are no gaps in the legal framework to enable the PUC to implement and regulate HERA.

[212] PUC annual Report 2016. Note that while the commission revenues are much higher than commission expenses, the commission is obligated to return send excess funds to other agencies (like the Consumer Advocate) and to the State's General Fund.

5.3 DSPP

The Distributed System Platform Provider ("DSPP") regulatory model requires the utilities to provide open access to distributed energy resources ("DER") and other providers by offering energy management or customer data analytics services. As DSPPs, the utilities essentially become the purchasers and aggregators for DER by upgrading the distribution network and then creating markets, tariffs, and operational systems to enable behind-the-meter resources to monetize products and services. Using this modernized grid platform provided by the DSPP utilities, customers, service providers, DER, and utilities conduct transactions of energy and services. Although the use of this model has the potential to increase the amount and costs of regulatory oversight, this model also expands the potential to open new revenue streams and to encourage the use of more DER.

In contrast to its position on the PBR regulatory model, Hawaii does not currently have a prior commitment to DSPP. Similarly, in contrast to its position on the HERA regulatory model, Hawaii has also not explicitly authorized (without requiring implementation of) the DSPP model. However, the Project Team's analysis in Task 2.2.6 revealed that use of DSPP in conjunction with Outcomes-based PBR (discussed in Section 5.1.1, above) and an IGO (discussed in Section 5.4, below) may comprise a preferable regulatory model for Hawaii to pursue due its ability to support a competitive distribution system, which will help control costs and rate volatility, efficiently allocate resources, fairly distribute risks, and fulfill state energy goals. Because Hawaii has not begun any planning or implementation process, this section examines all the steps, timeline, costs, and legal changes necessary to implement DSPP.

5.3.1 Steps and Timeline Approach for Transition to DSPP

The shift from utilities operating under the existing COS regulatory framework as vertically integrated entities to undertaking an additional role of DSPP requires significant regulatory work and efforts by the utilities. Due to the novel nature of the DSPP regulatory model, the State of Hawaii is well served by referring to another U.S. jurisdiction that is in the process of implementing DSPP. In determining the steps and timeline required for DSPP design and implementation, the Project Team concludes the regulatory shift occurring in New York State provides a particularly useful example.

Since 2014, New York ("NY") has been in the process of a significant regulatory change, which it calls Reforming the Energy Vision ("NY REV").[213] NY REV was created through the joint efforts of NY Governor Andrew Cuomo, the NY Public Service Commission ("PCS"), the New York Power Authority ("NYPA"), and other state agencies in response to the devastating effects of

---

213 "Governor Cuomo Announces Fundamental Shift in Utility Regulation," April 24, 2014, https://www.governor.ny.gov/news/governor-cuomo-announces-fundamental-shift-utility-regulation

Hurricane Sandy, which hit the NY area in October 2012.[214] Recognizing an urgent need to offset the effects of climate change by decarbonizing and making the grid more resilient, efficient, and economic, the State began the redesign of the regulatory system through the REV proceeding.[215] Specifically, under REV, regulators are able to transform traditional utilities into DSPPs, meaning the utilities facilitate the use of DER for use instead of tradition utility infrastructure to provide power to customers.

This transition for utilities to function as DSPPs is intended to address the oversized bulk power system in existence under the original model, which was designed to meet the relatively limited number of peak demand periods each year, as well as decrease costs and increase use of renewable energy sources, which are often distributed.[216] Other REV goals, which are achievable at least in part by the DSPP element of the model, include:

- Making energy affordable for all New Yorkers
- Building a more resilient energy system
- Empowering New Yorkers to make more informed energy choices
- Creating new jobs and business opportunities
- Improving our existing initiatives and infrastructure
- Supporting cleaner transportation
- Cutting greenhouse gas emissions 80% by 2050
- Protecting New York's natural resources
- Helping clean energy innovation grow[217]

To achieve these goals, the REV promotes the more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, broader deployment of DER such as microgrids, roof-top solar, and other on-site power supplies, and storage. REV also encourages markets to achieve greater use of advanced energy management products to enhance demand

---

[214] Other agencies include the New York Energy Research and Development Authority ("NYSERDA") and the Long Island Power Authority ("LIPA"). "About REV," https://rev.ny.gov/about/, accessed Sept. 21, 2018.

[215] Gavin Bade, Zibelman exit interview: how the New York REV is paving the way for transactive energy, Feb. 1, 2017, https://www.utilitydive.com/news/zibelman-exit-interview-how-the-new-york-rev-is-paving-the-way-for-transac/435252/

[216] NY REV supports the State's energy goals for 2030, which include a 40% reduction in GHG emissions from 1990 levels, a requirement that 50% of electricity must come from renewable sources, and a 23% decrease in energy consumption in buildings from 2012 levels (a 600 trillion Btu increase in statewide energy efficiency (at source)). https://rev.ny.gov/

[217] New York Dept. of Public Service, "Reforming the Energy Vision: About the Initiative," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

elasticity and efficiencies, which ultimately will empower customers to choose how they manage and consume electric energy.[218]

To determine the steps and timeline undertaken by New York to implement DSPP through the REV, the Project Team assessed the relevant documents from the NY REV docket proceedings and other related publications.

5.3.2 Steps and Timeline Necessary to Transition to DSPP

The Project Team's assessment of the steps and timeline necessary for the transition to a DSPP model is primarily informed by the experience of New York, which began the process of planning for and implementing DSPP in late 2013. Since the announcement that New York would undergo a comprehensive reconsideration of its regulatory framework, the state has initiated a large proceeding over the course of the past four years (including several additional dockets related to different elements of the regulatory framework) and worked with utility companies and other relevant stakeholders to plan and implement the various elements of the overall REV model, including the transformation of utilities to Distributed System Platforms. Although the proceeding is still ongoing and involves a redesign of the ratemaking process, this section focuses on the process undertaken by the state to transform the utilities into DSPPs.

At the time of this writing, the Project Team concludes that the Department of Public Service ("DPS") and the PSC had created a Distributed System Implementation Plan Guidance document, the utilities, and the PSC approved joint and individual Distributed System Implementation Plans ("DSIPs"), and the utilities have designed and implemented Demonstration Projects in their various service areas. Thus, New York and its utilities have laid considerable groundwork for the implementation of the DSPP model but have not yet fully implemented the model and have also not set a definitive deadline for the utilities to be fully functioning as DSPPs.

As discussed in Section 5.3.3, HI is a significantly smaller state than New York, and the utilities in most of the islands are under the same parent company, and therefore would probably require less time to implement the DSPP. Furthermore, the time spent on some of the steps taken by the NY DPS might be compressed in Hawaii.

A summary of the completed steps is listed in Figure 9, below.

Figure 9. Steps and Timeline to Implement DSPP in NY

[218] *Id.*

Summary of DSPP Steps and Timeline Already Taken	Action	Month
Step 1.	Statement of Intent to make a regulatory change and initial investigation	Month 1
Step 2.	Initial investigation; Opening of new regulatory proceeding	Months 1-4
Step 3.	Establish a preliminary schedule and approach for proceeding	Month 5
Step 4.	Stakeholder engagement and continued development of the REV	Months 5-14
Step 5.	Publication of initial proposals for regulatory changes	Month 9
Step 6.	Commission and utilities prepare additional mechanisms	Month 12
Step 7.	Issuance of an order adopting a policy framework and implementing a plan	Month 14
Step 8.	Development of REV demonstration projects	Months 18-23
Step 9.	Development of DSIP Guidance and Plans	Months 22-37
Step 10.	Continued planning under the adopted policy framework and implementation plan	Month 14+ (ongoing)

Source: New York Department of Public Service

5.3.2.1 Step 1. Statement of intent to make a regulatory change and initial investigation

In Month 1 in an Order dated December 26, 2013, in another proceeding,[219] the PSC directed the DPS Staff[220] to begin a process that would comprehensively reconsider New York's regulatory system and whether its retail and wholesale market designs were effectuating or impeding progress toward achieving the foundational policy objectives of the existing regulatory

[219] New York Department of Public Service, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Approving EEPS Program Changes, issued December 26, 2013. At 21

[220] Throughout the proceeding, DPS support the work of the PSC in an advisory capacity.

framework. The order then identified two key questions for consideration in a new regulatory proceeding that would assess and improve upon the regulatory framework:

a) *What should be the role of the distribution utilities in enabling system-wide efficiency and market-based deployment of distributed energy resources and load management?*

b) *What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving our energy policy objectives*?[221]

In addition to the primary questions to be answered, the Order also provided key policy outcomes desired, which are well indicated by the REV goals, listed in Section 5.3.1 above. The statements made in this Order constitute the statement of intent to assess the regulatory framework and to likely make sweeping changes, making way for the opening of the REV proceeding.

5.3.2.2 Step 2. Initial investigation; Opening of new regulatory proceeding

In Months 1–4, following the initial statement of intent and direction to the DPS Staff to consider the existing regulatory framework in the context of state policy goals, the PSC opened the REV proceeding docket (14-M-0101) on April 14, 2014. Attached as an appendix to this order was a report that was developed by DPS Staff at the instruction of the 2013 order above during the five months between that order and the initiation of the REV proceeding.

The report describes the implications of new trends in energy and climate change on the PSC's regulatory responsibilities. The report also describes a new business model for energy service providers (the DSPP model) in which DER "become a primary tool in the planning and operation of electricity systems, and in which customers are empowered to optimize their priorities with respect to reliability, cost, and sustainability."[222] The report also acknowledges the steps the state had already taken toward a distributed grid architecture and the evolution of the regulatory paradigm[223] and asks questions related to the functions of the DSPP to be addressed during the proceeding.

---

[221] *Id*. at 23

[222] New York Department of Public Service, Order Opening the REV proceeding, Case 14-M-0101, April 24, 2014 at 4.

[223] These include:

- DR at the distribution level, cooperation with NYISO bulk level demand response programs,
- PBR incentives – negative adjustments for failure to meet minimum service thresholds,
- Revenue decoupling mechanisms that make utilities indifferent to changes in sales volume that may result from customers adopting energy efficiency and distributed generation
- Interconnection standards of customer-sited generation connected to the distribution system
- Standby rates (to have utility available as a backup)
- Time of use rates (voluntary for smaller customers) to encourage off-peak usage
- Gas delivery rates for customers w/ DG

Notably, the report did not set a timeline or deadline for implementation of REV and the DSPP model. Instead, it set only preliminary deadlines for status reports on each Track of the project (due July 2014) and generic policy decisions for each (September 2014 for Track One, First Quarter 2015 for Track 2),[224] and highlighted the time-intensive nature of preparing and implementing the REV.[225]

5.3.2.3 Step 3. Establish a preliminary schedule and approach for proceeding

In Month 5, an Administrative Judge for this proceeding worked with the stakeholders to establish an initial schedule for the next several months. The schedule included working group meetings, technical conferences, and the issuance of a straw proposal for each track by DPS staff, and party comments to the proposals.[226]

5.3.2.4 Step 4. Stakeholder Engagement and continued development of the REV

In Months 5 - 14 and ongoing, following the initiation of the proceeding and establishment of a timeline for initial tasks, the PSC and DPS received comments from stakeholders including the utility companies and the NYISO. Nearly 300 parties participated in these collaborative efforts and offered informal guidance on major policy issues. Under the leadership of two administrative law judges, the parties formed two working groups and five committees (markets; customer engagement; platform technology; microgrids; wholesale markets). In July 2014, these groups filed reports with the PSC and presented results at a technical conference before the Commission. They were also invited to submit preliminary comments on policy issues to guide the DPS Staff's

---

- Energy efficiency programs
- Customer sited clean energy programs under the RPS
- Advanced energy technology research and development programs
- A green bank to facilitate financing of advanced energy projects
- Implementation of statutory net metering requirements.

Case 14-M-0101. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, DPS Staff Report and Proposal, at 10.

[224] Track One began immediately and focused on the DSPP issues detailed in the report. The status report on these issues was due July 10, 2014. The Staff also stated a goal to reach a generic policy determination on DSPP by the end of 2014.

Track Two focuses on regulatory changes and ratemaking issues. It is conducted in parallel to Track One, but does not adhere to the same deadlines. The initial Staff straw proposal was anticipated by mid-July, 2014, to be followed by a collaborative discussion of the issues, and a status report on regulatory reform issues on September 4, 2014. The PSC expected to reach a generic policy determination on this Track in the first quarter of 2015. Order Opening REV Proceeding, at 6-7.

[225] *Id*. at 65

[226] Case 14-M-0101, Ruling Establishing Collaborative Agenda and Working Schedule, Issued May 1, 2014.

development of their proposals.[227] Following the Commission's issuance of the straw proposal and notice of proposed rulemaking, as well as the draft generic EIS, stakeholders were able to provide comments. The Commission also held public statement hearings throughout the state,[228] as well as a second technical conference in Month 11.

5.3.2.5 Step 5. Publication of initial proposals for regulatory changes

In Month 9, the PSC published the straw proposal for Track One (August 22, 2014) (Track Two, was delayed). Following this publication, stakeholders continued to submit comments and engage in the planning process.

5.3.2.6 Step 6. Preparation of additional mechanisms by the Commission and the utilities

On December 11, 2014, (Month 12 of the process) the Commission ordered each utility to develop a demand response tariff, to participate in ongoing efforts to establish dynamic load management measures and to adhere to a Resolution issued by the Commission for guidance on demonstration projects. The Commission also initiated a process to examine long-term alternatives that would accomplish the purpose of net metering more efficiently.

5.3.2.7 Step 7. Issuance of Order Adopting Policy Framework and Implementing Plan

On February 26, 2015 (in Month 14 of the process), the Commission issued and put into effect an Order Adopting Policy Framework and Implementing a plan for the Track One policy issues, including the development of the DSPP. The order summarized all previous work done and ordered the creation by the utilities of DSIPs and provided guidance on what the DSIPs must include, as well as a schedule for additional REV implementation matters.

5.3.2.8 Step 8. Development of REV demonstration projects

Beginning in month 18 by the February 26, 2015 Order of the Commission, the joint utilities began submitting proposals for demonstration projects, which are intended to exhibit new business models that fit within the REV framework. Specifically, these projects should inform decision makers related to developing DSP functionalities, measuring customer responses to various programs and prices associated with the REV model, and to determine the most effective implementation of DER.[229] DPS began releasing assessments of some demonstration projects in month 23. During the entire period and through the current date, utilities have begun operations of approved demonstration projects, and have also submitted applications for new ones.

---

[227] Order Adopting Regulatory Policy Framework and Implementing Plan, Case 14-M-0101, issued and effective Feb. 26, 2015.

[228] Public statement hearings were conducted in Buffalo, Syracuse, Albany, Kingston, Binghamton, Rochester, Yonkers, and New York City.

[229] New York Department of Public Service, "REV Demonstration Projects," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

Following operation of a demonstration project, the utility must (and does) submit status updates or quarterly reports to the Commission.

5.3.2.9 Step 9. Development of Distributed System Implementation Plan Guidance and Plans

Beginning in Month 22, the DPS published a proposal for DSIP guidance, and the joint utilities filed their comments nearly two months later. The DSIP guidance was later adopted in month 28 on April 20, 2016. Then in Month 37, on March 9, 2017, the Commission released an order on Distribution System Implementation Plan Filings. The Order required utilities to submit filings by October 1, 2017, to document that the hosting capacity analysis for all circuits at and above 12kV had been completed and that Phase 1 of the interconnection portals had been fully implemented.

The Order also required utilities to show within 60 days that all sustainability criteria will be incorporated into the utility planning procedures and capital plans, and within 90 days all proposed building energy management and benchmarking data standards for the Commission's consideration. Finally, the order required utilities to file documentation of deploying energy storage projects that are operating at no fewer than two separate distributions substations or feeders, as discussed in the order by December 31, 2018.

5.3.2.10 Step 10. Continued Planning under the Adopted Policy Framework and Implementation Plan

In Months 14 and onward, following the Commission's adoption of a policy framework and implementation plan, the Commission, and the parties continued to work to continue to develop the framework according to the plan. Two examples of this are the joint utilities submission of a technical resource manual management plan on June 1, 2015, and the publication by the DPS staff of the Benefit-Cost Analysis ("BCA") Framework Whitepaper. Both submissions were then open to a comment period and subsequent revisions and approvals. In particular, the BCA whitepaper, which received comments on August 21, 2015, was then used by the Commission to establish the BCA Framework on January 21, 2016. The BCA Framework required the joint utilities to file BCA handbooks by June 30, 2016, in compliance with that order.

This process was repeated throughout the following months through to the current day for other issues including setting standards for a code of conduct, an interconnection earning adjustment framework and voluntary time of use rates.

5.3.2.11 Anticipated Next Steps

Although it is difficult to determine what the next steps for the PSC are regarding the planning and implementation of the DSPP model, it is clear that certain tasks must occur. The Project Team anticipates a continuation and expansion of the demonstration projects, as well as continued development and improvement on the various mechanisms identified as necessary to implement the DSPP model. Because no ultimate deadline was published, nor a comprehensive status update in terms of current progress as part of the completed initiative, the Project Team is unable to determine how long the proceeding will continue before DSPP is actually in effect among all the utilities. The PSC has also noted that this process will be time consuming and ongoing.

5.3.3 Steps and Timeline to Implement DSPP in Hawaii

Based on the analysis of New York's ongoing process to implement DSPP as part of the REV initiative, it is clear that the regulatory transition to DSPP is a time consuming and complex endeavor. It is also clear that the process used by New York is very collaborative, utilizing the expertise and opinions of relevant state agencies, legal experts, nonprofits (as intervenors) and the utility companies. New York undertook many different initiatives to assess, draft, reassess and implement various elements of the REV and DSPP regulatory models, which inherently requires time for all the parties to meaningfully participate, and for the utilities and the PSC, in particular, to make the appropriate changes in their plans and operations.

Although New York has made significant progress towards implementing DSPP over four years, the PSC noted that the process would be ongoing, and in fact, the PSC and utilities have not yet completed the full transition. Notably, although Hawaii's regulatory scene has its own complexities, Hawaii is a significantly smaller state than New York, with fewer utilities and a smaller grid to work with as it develops such a model. With this in mind, the Project Team projects that if Hawaii were to undertake similar steps as New York, it would be able to implement DSPP by 2028.

5.3.4 Transition Costs of DSPP

The transition costs of a DSPP model are highly uncertain as the primary precedent for the model (the New York REV process) has not yet been fully implemented. This analysis primarily considers the costs that would be borne by Hawaii's utilities in the transition to a DSPP model. In addition to these direct transition costs, Hawaii's utilities and PUC alike would incur costs related to the lengthy process to plan the transition to a DSPP model.

5.3.4.1 New York REV Demonstration Project Budgets

While the full costs of implementing the DSPP model in New York are not yet known, budgetary information from early REV demonstration projects that are similar in nature to the DSPP model that would eventually be implemented across Hawaii provides key insights to the state's potential transition costs. One such demonstration project, National Grid's Distributed System Platform demonstration project in Buffalo, New York, forms a key data point in the determination of potential costs. This project, located on the Buffalo Niagara Medical Campus, is designed deploy many of the DSPP concepts included in REV (such as the locational value of customer generation resources, and the development of a platform to allow these assets to provide grid services) on a pilot basis.[230]

[230] Niagara Mohawk Power Corporation D/B/A National Grid: Distributed System Platform Rev Demonstration Project – Q2 2018 Report, Case 14-M-0101. July 31, 2018.

The National Grid demonstration project is designed to serve a potential distributed resource capacity of 63.5 MW across several locations.[231] National Grid initially budgeted $4.81 million for a three-year implementation project, $3 million of which would go to a third party software provider (after accounting for a $2 million cost share), and $1.81 million of which would cover National Grid's own costs (on an annual basis, these costs equate to $1 million in software development costs and $603,000 in internal costs. After the start-up period, National Grid anticipated annual operating cost of $200,000 in software licensing and $30,000 in utility expenditures. [232] Through June 2018, the demonstration project is two-thirds of the way through the pilot start-up period and has spent 55% of its project budget.[233]

5.3.4.2 Estimate of Operational Costs in Hawaii

The Project Team scaled these costs of implementing the DSPP model in the Buffalo pilot project to Hawaii by the amount of distributed generation resources served – direct software costs were not scaled as these were assumed to be a relatively fixed cost. In HECO's Power Supply Improvement Plan, the utility projects 1,698 MW of DG capacity to be implemented in 2045 (this number excludes Kauai, for which a formal utility-published DG forecast is not available).

Scaling these the costs of the Buffalo REV demonstration project directly from the 63.5 MW of targeted capacity from the Buffalo pilot to the 1,698 MW targeted capacity in Hawaii would result in an annual cost of $17.1 million during the three-year start-up period (including $1 million annually in software costs), and $1 million in annual operating costs following the start-up period (including $200,000 in software costs).

5.3.5 Conclusions on Steps, Timeline, and Costs for Transition to DSPP

The transition from a vertically integrated utility model to including DSPP has been experienced and documented to the extent necessary for comparison only by New York's REV proceeding, which consists of the creation of a DSPP model. Additional uncertainty in the steps, timeline, and cost arise from the fact that New York is still in the process of implementing the DSPP. However, the Project Team notes that steps Hawaii might anticipate in creating a DSPP model include stating an intent to make the regulatory change, opening an investigation and regulatory proceeding, establishing a schedule and engaging stakeholders, creating and publishing guidelines and policy frameworks, and possibly developing demonstration projects. Based on New York's timeline, the Project Team estimates these initial processes of developing a policy plan and other elements of the plan could take up to three years due to the complexity and novelty of the topic. However, it is also possible that the initial startup will require less time since Hawaii is significantly smaller and has fewer regulatory players than New York does. Regardless, this

---

[231] Niagara Mohawk Power Corporation D/B/A National Grid: Distributed System Platform Rev Demonstration Project – Q2 2018 Report, Case 14-M-0101. July 31, 2018.

[232] Niagara Mohawk Power Corporation D/B/A National Grid: Implementation Plan for Distributed System Platform REV Demonstration Project, Case 14-M-0101. August 15, 2016.

[233] *Id.*

tentative deadline leaves sufficient time for completion by 2028 to implement DSPP. In terms of costs, despite significant uncertainty, the Project Team estimates that the cost to implement the DSPP model to be will be $51.4 million, spread over three years, with a $1 million annual operating cost thereafter.

5.3.6 Legal Considerations for DSPP

In contemplating whether to implement the DSPP model in Hawaii, it is important to consider whether a legal framework exists in Hawaii that permits its implementation. In particular, it is essential to take into account whether the state has the authority to impose the DSPP model on the utilities and whether it has the power to regulate the utilities as DSPPs. In this analysis, Project Team considers both the legality of the existing DSPP model currently being implemented in New York, as well as the current legal framework in Hawaii and any legal changes that may be necessary.

5.3.6.1 Legal Framework for DSPP in New York

New York has begun planning for and implementing the DSPP model as part of the REV initiative, as discussed above. In the Order Adopting Regulatory Policy Framework and Implementation Plan, the PSC noted the authority derived from New York statutes and case law that provide the authority for the REV proceeding.[234] One statute highlighted in the order is Public Service Law ("PSL") section 65(1), which provides that the Commission is responsible for ensuring that electric corporations "furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable."[235] The other statute referenced is PSL section 5(2), which states:

> *The Commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or collectively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, and preservation of environmental values and the conservation of natural resources.*[236]

Additionally (though not specifically highlighted in the Order), the jurisdiction, power and duties of the PSC extend to "the manufacture, conveying, transportation, sale or *distribution* of gas (natural or manufactured or mixture of both) and electricity for light, heat or power, to gas plants and to electric plants and to the persons or corporations owning, leasing, or operating the

[234] Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101, February 26, 2015

[235] *Id.*; NY Pub. Serv. L. § 65(1).

[236] NY Pub. Serv. L. § 5(2).

same."[237] Although ratemaking is not explicitly included under this statute, it is confirmed to be included as part of the PSC's authority as well.[238]

Based on these statutes and case law, it is clear that the NY PSC has the authority to regulate utilities in their traditional role, as well as their developing role as distribution service platform providers. It is also clear that the Commission has the authority to ensure safe and adequate utility service and to carry out long-range planning programs, such as the REV. Additionally, the New York courts have concluded that the Commission has the responsibility "to adjust its regulatory framework in response to the evolving circumstances and foreseeable trends, in order to meet customers' needs," and these adjustments "may include innovative, market-based tools and the formation of new business models."[239] Indeed, the PSC's actions to introduce competition into a monopolistic marketplace to lower prices to consumers, as well as the PSC's actions to require energy efficiency and demand management programs have been upheld by the court.[240] Finally, as an executive agency, the PSC enjoys judicial deference under administrative law principles.[241]

It is worth noting that aside from legislation codifying the state's energy plan,[242] the requirement that every agency of the state conduct its affairs so as to conform to the state energy policy,[243] and the REV proceeding itself,[244] no new legislation was introduced in order to legalize or enable the process of implementing DSPP or the REV initiative more generally. Additionally, at the time of this writing (nearly four years into the proceeding), it appears that the effort has not been challenged, and all relevant agencies and utility companies are engaging in the process to implement the REV and the DSPP model. Therefore, the Project Team concludes that the legal framework in place in New York is sufficient to enable the PSC to plan for, implement, and regulate under the REV model, including the creation and use of DSPPs.

---

[237] NY Pub. Serv. L § 5(1)(b) (Emphasis added).

[238] Porr v. NYNEX Corp. (2 Dept. 1997) 230 A.D.2d 564, leave to appeal denied 91 N.Y.2d 807, 669 N.Y.S.2d 260, 692 N.E.2d 129.

[239] Order Adopting Regulatory Policy Framework and Implementation Plan, Case No. 14-M-0101, February 26, 2015, citing Cases 94-E-0952 et al., Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service (issued May 20, 1996), and Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924 (Albany County Sup. Ct. 1996).

[240] Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924, 936 (Albany County Sup. Ct. 1996).

[241] *See,* Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).

[242] NY Energy § 6-104; Specific regulations reflective of the content in the 2015 State Energy Plan codified in 9 NYCRR §§ 7840.1 – 7863.1.

[243] NY Energy § 3-103.

[244] Case 14-M-0101.

5.3.6.2 Legal Framework for DSPP in Hawaii

As was stated above in Section 4.3.3, the Hawaii Public Utilities Commission ("PUC") has general supervision over all public utilities and must perform the duties and exercise the powers imposed or conferred upon it by law.[245] This includes regulating rates, opening investigations, and acting as an enforcement agency for the regulated entities, all in the furtherance of the public interest. In addition to these responsibilities, the Commission is also required to consider other regulatory impacts in the context of achieving the State's energy goals.

Under this regulatory framework, "public utilities" are defined as including any entity "who may own, control, operate, or manage…any plant or equipment, or any part thereof… for the production, conveyance, transmission, delivery, or furnishing of light, power, heat, cold, water, gas, or oil."[246] Section 4.3.3 also discussed how this legal description qualified the HECO Companies and KIUC as public utilities for the purpose of the statutory framework. Additionally, a careful reading of this definition includes, as it did in the New York statute, entities that transmit or deliver power. This language is important because, on its face, it includes PUC regulation of the utility companies even if their roles shift to DSPPs, as proposed in this model.

Based on the laws that inform the PUC in its regulation of public utilities, as well as the nature of the DSPP model, it appears that the extension or evolution of the utility companies' duties to become the purchasers and aggregators for DER and to engage in activities that enable behind-the-meter resources to monetize products and services would fall under the PUC's regulatory purview. Additionally, this kind of model is part of the regulatory shift specifically contemplated by the PUC in its 2014 whitepaper, the Commission's Inclinations on the Future of Hawaii's Electric Utilities.[247] In the Inclinations, the Commission articulated the role of "modern transmission-and-distribution systems integrator" as a key business function for the utility companies of the future in Hawaii. The paper details "[this] business strategy focuses on energy delivery would enable the HECO Companies to concentrate on developing a world-class, modern island grid infrastructure to accommodate and deliver substantial quantities of clean energy sources."[248] Therefore, the Project Team concludes that there is likely no legal action required for the Commission to lawfully implement the DSPP model.

However, the Project Team also notes that due to the novel nature of the regulatory model, the timeframe in which the transition to DSPP will likely occur (implementation in 2028), and the approach the state has taken to other regulatory shifts or initiatives, the state could benefit from passing legislation that requires a transition to DSPP to the extent that is the preferred model.

---

245 Haw. Rev. Stat. § 269-6

246 Haw. Rev. Stat.§ 269-1(1)

247 The Inclinations at 1.

248 *Id*. at 21.

This would follow the same example as the PBR law,[249] in which the legislature created a requirement to shift to a specific regulatory model even though the PUC could engage in such a transition on its own. The Project Team anticipates that such legislation would be viewed as aligned with the state's energy goals and would be a timely step in the implementation of DSPP. This step should create clarity and ease for the parties and would help to prevent the possibility of any future legal challenges.[250]

5.4 IGO

An Independent Grid Operator ("IGO") is an independent entity that manages the dispatch and planning functions. The IGO would be able to manage both transmission and distribution assets due to the relatively small size of these in Hawaii. This is in contrast to ISOs, detailed below, which manage transmission assets only on a much larger scale. Additionally, the IGO helps to address conflicts of interest and ensure impartiality in interconnection and reliability analyses. This function may be particularly useful when implemented together with the DSPP model, above, due to the increased likelihood of conflicts of interest for the utility as and greater complexity of the grid that are probable under that model.

IGOs are comparable to Independent System Operators ("ISOs") that exist in other parts of the country. Even though most ISOs on the US mainland are regulated by FERC and that any Hawaii IGO would not be regulated by FERC, the Project Team finds this comparative analysis valuable due to the broad functional similarities a Hawaii IGO is anticipated to have with a FERC regulated ISO/RTO. ISOs were conceived of by the FERC as a method to "remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity customers."[251]

As envisioned by FERC in its 1996 Order 888, the ISOs are purposed with operating the transmission systems of public utilities in a way that is independent of any business interest in sales or purchases of electric power by those utilities.[252] In a later order, FERC amended its regulations under the Federal Power Act ("FPA") to advance the formation of Regional Transmission Organizations ("RTOs"). Under the new regulations, FERC codified the minimum characteristics and functions for the RTOs and required that each public utility or other entities engaged in interstate energy transmission make certain filings with respect to forming and

---

[249] Hawaii Ratepayer Protection Act.

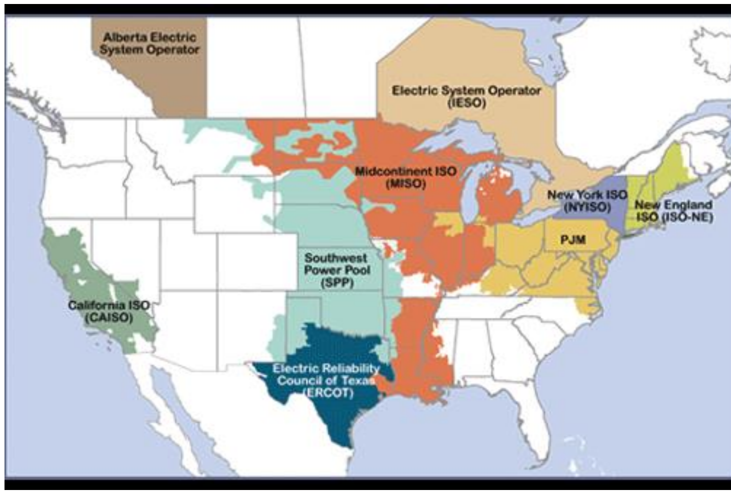
[250] The Project Team emphasizes that DSPP appears to be legal under the existing framework. Nonetheless, legal challenges can present a time-consuming and expensive challenge regardless of their merits.

[251] 75 FERC ¶ 61,080 (FERC Order 888, Issued April 24, 1996, at 1)

[252] 75 FERC ¶ 61,080 (FERC Order 888, Issued April 24, 1996, at 280). Note also that Order 889, also released on April 24, 1996, amended rules establishing and governing the Open Access Same-Time Information System (OASIS) and prescribed standards of use and access for the system as a means to provide open access to transmission and transmission information.

participating in an RTO.[253] ISOs are also similar to RTOs, although are not held to the same degree of responsibility by FERC.[254] The distinction between RTOs and ISOs is that ISOs can be formed at the direction or recommendation of FERC, but might not meet FERC's minimum requirements of an RTO, or have not petitioned FERC for the status to become an RTO. However, it appears that most existing ISOs[255] are also characterized together with RTOs by FERC.[256]

Figure 10. FERC Map of RTOs/ISOs



[257]

[253] 89 FERC ¶ 61,285 (FERC Order 2000, issued Dec. 20, 1999, at 1). The minimum characteristics and functions that an RTO must satisfy are:

Minimum Characteristics:

1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability

Minimum Functions:

1. Tariff Administration and Design
2. Congestion Management
3. Parallel Path Flow
4. Ancillary Services
5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
6. Market Monitoring
7. Planning and Expansion
8. Interregional Coordination

[254] Compare, FERC Order 888 and FERC Order 2000; However, both ISOs and RTOs within FERC's jurisdiction are subject to NERC oversight. 16 U.S.C. § 824o (2012).

[255] This excludes the Electric Reliability Council of Texas ("ERCOT"), which is not registered with or subject to FERC's jurisdiction. See Section 5.4.2.3, infra.

[256] FERC, Regional Transmission Organizations (RTO) / Independent System Operators), accessed Sept. 25, 2018, https://www.ferc.gov/industries/electric/indus-act/rto.asp?csrt=2042728201376846909. Based on the available map, it appears that the PJM Interconnection and the Southwest Power Pool are the only two entities that are exclusively RTOs.

[257] *Id*.

As was true with the DSPP model (and in contrast to the PBR and HERA models), Hawaii does not currently have a prior commitment to creating an IGO. However, the Project Team's analysis in Task 2.2.6 revealed that use of an IGO in conjunction with an Outcomes-based PBR (discussed in Section 5.1.1, above) and the DSPP model (discussed in Section 5.3, above) may achieve most of the state goals due to its ability to support a competitive distribution system, which will help control costs and rate volatility, efficiently allocate resources, fairly distribute risks, and state energy goals. Because Hawaii has not begun any planning or implementation process for an IGO, this section examines all the steps, timeline, costs, and legal changes necessary to create an IGO.

5.4.1 Steps and Timeline Approach for Creation of an IGO

Because Hawaii has not previously made efforts to create such an entity as part of its regulatory framework, it is useful to draw on the processes undertaken by other states that have an ISO. In particular, the Project Team examines the steps, timeline, costs, and legal considerations of the New York for the New York Independent System Operator ("NYISO"), in California for the California Independent System Operator ("CAISO"), and in Texas for the Electric Reliability Council of Texas ("ERCOT"). To determine the steps and timeline undertaken to create these ISOs, the Project Team assessed publicly available information about each entity, including their websites and docket proceedings.

5.4.2 Steps and Timeline Necessary for Creation of an IGO

The steps and timeline necessary for the creation of an IGO vary among the jurisdictions that have ISOs. Because ISOs are nonprofit organizations, they are typically created either voluntarily by the utility companies, as was the case for NYISO and ERCOT, or have also been created by the state legislature, as CAISO was. Notably, the process for creating an ISO appears to occur outside of the typical docket process that was so integral for the other regulatory changes considered in this report. The following sections explain the steps and timelines used to create NYISO, CAISO, and ERCOT.

5.4.2.1 NYISO

The New York Independent System Operator ("NYISO") is a not-for-profit, independent company that is led by an independent Board of Directors. The company is unaffiliated with any state or federal agency or energy company and is responsible for operating the state's bulk electricity grid, administering the state's competitive wholesale electricity markets, conducting comprehensive long-term planning for the state's electric power system, and advancing the technological infrastructure of the electric system serving the state.[258] The NYISO performs these

[258] FERC, New York Independent System Operator, https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf, at 197

duties under the strict regulatory oversight of FERC, NERC, the New York State Reliability Council ("NYSRC"), the Northeast Power Coordinating Council ("NPCC"), and the PSC.[259]

The NYISO as it exists today evolved from a much older entity, the New York Power Pool ("NYPP"). The NYPP was created voluntarily by the State's investor-owned utility companies following the Northeast Blackout of 1965 in order to coordinate the reliable operation of the respective power systems by managing energy supply and demand, transmission voltage, system contingencies, operating reserves, and dispatched generation.[260] The NYPP later included NYPA in 1967[261] and continued its operations until 1997, when it filed a proposal with FERC to form an Independent System Operator. This occurred as the PSC was restructuring the New York market to increase competition. The proposal was approved in 1998, and the NYISO officially began its operations and control of the New York electric power system on December 1, 1999. Participants in New York's wholesale electricity markets pay a small surcharge which covers the costs to run the NYISO.[262]

Summary of steps taken to create the NYISO: The NYPP was created by the utility companies to manage the grid reliability in response to the Northeast Blackout of 1965. The NYPP operated for more than thirty years. Then, following the deregulation of the New York market and the initiative of FERC to authorize ISOs, the NYPP applied to FERC to become an ISO. The time between NYPP's application to FERC and the beginning of official operations as an ISO was about 2 years.[263]

5.4.2.2 CAISO

The California Independent System Operator ("CAISO") provides "open and non-discriminatory access to the bulk of the state's whole transmission grid [and a small part of Nevada's grid], supported by a competitive energy market and comprehensive infrastructure planning

---

[259] NYISO, Who We Are, accessed Sept. 25, 2018, https://home.nyiso.com/who-we-are/

[260] New York Independent System Operator, Inc., NYISO Agreements, August 8, 2012, available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/Agreements/NYISO/nyiso_to_agreement.pdf, which states "Whereas, the Investor-Owned Transmission Owners established the New York Power Pool ("NYPP") by agreement made as of this 21st day of July, 1966,…"

[261] Eric Anderson, 50 Years Ago Albany Went Dark in the Great Northeast Blackout, Times Union, Nov.12, 2015. https://www.timesunion.com/tuplus-business/article/50-years-ago-mdash-Albany-went-dark-in-the-6616751.php

[262] NYISO, Frequently Asked Questions, accessed Sept. 25, 2018, https://home.nyiso.com/faq/ ; FERC, 2010 RTO/ISO Metrics Report: NYISO, https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf

[263] New York Independent System Operator, Introduction to the NYISO, July 21, 2011, available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/councils/consumer_advisory_council/Introduction_to_the_NYISO.pdf at 3.

efforts."[264] The CAISO is a nonprofit public benefit corporation that was created by the California Legislature in Assembly Bill 1890 in 1996.[265] The bill was designed in response to the passage of the federal Energy Policy Act of 1992,[266] and caused the restructuring of the state's power market. The CAISO was incorporated in May 1997 and began operations, including managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions, in March 1998.[267]

In addition to the fact that the CAISO was created by the state legislature, the CAISO is also unique from other ISOs assessed in this report in the composition of its board of directors. Whereas ISOs typically are led by a board of directors comprised of independent members, the CAISO's board is appointed by the state.[268] To transfer control of transmission facilities to the CAISO and implement the restructuring envisioned by the legislation, the three largest investor-owned electric utilities in California filed a joint application with FERC to transfer control of

---

[264] California ISO, "About Us," accessed Sept. 24, 2018, http://www.caiso.com/about/Pages/default.aspx

[265] California Assembly Bill No. 1890, September 23, 1996 (Stats. 1996, c. 854 (A.B. 1890), § 10, eff. Sept. 24, 1996) (codified in part, e.g., as West's Ann. Cal. Publ. Util. Code § 330).

> 1(c) It is the intent of the Legislature to direct the creation of a proposed new market structure featuring two state chartered, nonprofit market institutions; a Power Exchange charged with providing an efficient, competitive auction to meet electricity loads of exchange customers, open on a nondiscriminatory basis to all electricity providers; and an Independent System Operator with centralized control of the statewide transmission system. A five-member Oversight Board comprised of three gubernatorial appointees, an appointee of the Senate Committee on Rules and an appointee of the Speaker of the Assembly will oversee the two new institutions and appoint governing boards that are broadly representative of California electricity users and providers. A.B. 1890
>
> The legislature found that the "commission has properly concluded that (1) this competition will best be introduced by the creation of an Independent System Operator and an independent Power Exchange."

[266] The Energy Policy Act of 1992 was designed to decrease the country's dependence on imported energy, promote energy conservation, and provide incentives for clean and renewable energy. 102nd Congress H.R. 776 ENR.

[267] FERC, "California Independent System Operator Corporation (California ISO)," https://www.ferc.gov/industries/electric/indus-act/rto/metrics/caiso-rto-metrics.pdf

[268] California Assembly Bill No. 1890, September 23, 1996. Notably, the formation and method of formation of this unique board of directors was the subject of judicial review. Ultimately, the court ruled FERC did not have the authority to enforce their order to restructure the board of directors to be more aligned with ISO requirements. The court continued, reasoning that if FERC did not approve, it could remove CAISO's ISO status, but could not compel them to amend their practices as a separate order.

> "FERC has the authority not to accept something which it does not deem an ISO. It does not have the authority to reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a "practice" for ratemaking authority purposes."
>
> *California Independent System Operator Corporation v. FERC*, 372 F.3d 395, 404 (DC Cir. 2004).

transmission facilities to CAISO and to sell electricity to the Power Exchange.[269] Because California's grid includes interstate transmission lines, CAISO is subject to FERC regulation.

Summary of steps taken to create the CAISO: To create the ISO, California wrote and passed legislation through the state legislature, and then implemented the requirements in the legislation, including assigning a board of directors, and transferring control of the transmission facilities to the ISO via FERC application, which was required because California is subject to FERC's jurisdiction. This process took about two years to complete.

5.4.2.3 ERCOT

The Electric Reliability Council of Texas ("ERCOT") is the ISO for the Texas region and manages power on the electric grid for about 90 percent of the state's electric load.[270] More specifically, ERCOT's primary tasks include scheduling the power on the grid, performing financial settlement for the competitive wholesale bulk-power market, and administers retail switching for seven million premises in competitive choice areas.[271] ERCOT is a membership-based 501(c)(4) nonprofit corporation whose members include "consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution power providers and municipally owned utilities."[272] ERCOT is governed by an independent board of directors and subject to oversight by the Texas PUC and the Texas Legislature.[273] Notably, although ERCOT is an ISO, the ERCOT grid is generally not subject to FERC regulation due to its insulation within the State of Texas and lack of interstate transmission lines. Due to its independence from federal regulation, ERCOT was created by the state and did not need FERC approval for its creation and is not subject to FERC oversight for regulatory

---

269 Pacific Gas & Electric Co., 77 FERC ¶ 61,204 (1996).

270 ERCOT, "About" accessed Sept. 28, 2018, http://www.ercot.com/about

271 ERCOT Quick Facts, Aug. 8, 2018, http://www.ercot.com/content/wcm/lists/144926/ERCOT_Quick_Facts_8818.pdf

272 ERCOT, "About" accessed Sept. 28, 2018, http://www.ercot.com/about

273 *Id.*

changes.[274] The Texas PUC confirms this, stating that ERCOT is "[t]he only ISO created under state law, not by FERC."[275]

ERCOT's predecessor, the Texas Interconnect System ("TIS"), was created in 1941 by several electric utilities that joined together to support the war effort by sending excess power supplies across Texas to the Gulf Coast for aluminum smelting activities. Their war effort demonstrated to the companies the benefits of interconnection for reliability, and they continued to use and develop the interconnected grid into the future. Decades later, following the new NERC requirements that arose following the Northeast Blackout of 1965, TIS formed ERCOT to comply with NERC requirements,[276] although TIS still operated as its own, large entity until 1981, when it transferred all operating functions to ERCOT. During the 1990s, amid local and national support for deregulation of electricity markets, ERCOT's role grew. In 1995, the Texas Legislature voted to deregulate wholesale generation, and the Texas PUC began to expand ERCOT's responsibilities to include and enable wholesale competition and efficient use of the power grid for all market participants. On August 21, 1996, the Texas PUC endorsed an electric utility joint task force recommendation that ERCOT become an ISO, and on September 11, the ERCOT Board restructured the entity as a nonprofit ISO and became the first ISO in the country. Since then, ERCOT has continued to function as an ISO for the State of Texas.[277]

Summary of steps taken to create the ERCOT: To create the ERCOT ISO, Texas utilities first voluntarily created a reliability organization that encouraged and oversaw the interconnection of

---

[274] See FERC, "ERCOT," https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp

See also: "FERC has limited jurisdiction over ERCOT because the ERCOT system is isolated from the rest of the nation's power grid with the exception of two non-synchronous interconnections. s. Under Section 201(b)(1) of the Federal Power Act, the Commission does not have jurisdiction over facilities used for the generation of electric energy, or over facilities used in the local distribution or only for the transmission of electric energy in intrastate commerce except as provided in other portions of the Act. One exception is provided in Section 201(b)(2) of the FPA, which provides that the Commission does have jurisdiction over the connection of co-generation facilities to the grid under Section 210 and over wheeling between utilities under Sections 211 and 212 without regard to the limitations of Section 201(b)(1). The Commission also has jurisdiction over the two interconnects between ERCOT and the adjoining grid based on a settlement under Section 211. The Commission also has limited jurisdiction over assets of holding companies that own facilities in ERCOT and outside ERCOT, and as such are subject to the Public Utility Company Holding Act of 1935 for purposes of mergers, consolidations, and the competitive aspects of corporate control. However, the Commission does not have the comprehensive jurisdiction over the ERCOT transmission grid that it does over transmission grids located in other parts of the country." FERC, Investigation of Bulk Power Markets, ERCOT (Texas), Nov. 1, 2000, available at https://www.ferc.gov/legal/maj-ord-reg/land-docs/ercot.PDF at 4-1.

[275] Tom Hunter, Public Utility Commissioner of Texas, History of Electric Deregulation in Texas, Electric and Gas Reliability Workshop, April 17, 2012, available at https://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf

[276] Recall that NERC's jurisdiction includes users, owners, and operators of the bulk power system for North America. NERC, "About NERC," accessed Sept. 28, 2018, https://www.nerc.com/AboutNERC/Pages/default.aspx .

[277] ERCOT, "History," http://www.ercot.com/about/profile/history .

the electrical grid within Texas. Over time, this organization adapted to accommodate changes in the market including deregulations and finally became a non-profit, independent entity that qualified as an ISO. The time from when the Texas legislature and PUC decided to expand ERCOT's role to become an ISO to when it became an ISO was less than 2 years.

5.4.2.4 Additional Considerations for Hawaii Steps and Timeline

Although the publicly available information for the above ISOs provided relatively straightforward methodologies for creating their ISOs, the Project Team anticipates that additional steps may be required for some methods that the state of Hawaii may pursue to create its IGO. This is based on an assessment of comparable initiatives undertaken in Hawaii, that are discussed in Section 5.4.5.1, below. In sum, the additional steps are likely to include an investigatory proceeding into the creation of an IGO, the results of which will inform action by the state legislature. This general process has been detailed in sections 4.3 and 5.2.4, above.

5.4.3 Transition Costs of Creating an IGO

The costs of forming and managing an IGO may be estimated based on the long history of such entities in the mainland US. However, as with other regulatory models, there is substantial uncertainty in scaling these costs to Hawaii as all existing examples of the IGO model cover significantly larger service areas than a potential Hawaii IGO. A critical issue in the estimation of IGO transition costs in Hawaii will be the degree to which implementation costs may be scaled down to reflect the smaller size of Hawaii's grid.

5.4.3.1 Transition and Operational Costs of Mainland IGOs

The Project Team's assessment of potential IGO transition costs is based on analysis previously conducted by the FERC on the investment outlay and annual operating costs of RTOs in the United States.[278]

At the time, FERC staff noted that investment requirements for new RTOs had ranged from $38 million to $116 million ($51 million to $157 million in 2018 dollars), and annual operational costs had ranged from $35 million to $78 million ($47 million to $105 million in 2018 dollars). FERC projected that new entities would benefit from the lessons learned of existing organizations and be able to implement a new RTO with both initial investment costs and annual operating costs falling in the range of $50 million to $70 million ($67 million to $94 million in 2018 dollars).

FERC also projected these costs on a $/kWh basis, noting a median cost of $0.2 per MWh ($0.27/MWh in 2018 dollars) in existing RTOs, equivalent to an average rate impact of 0.3%. However, FERC noted that $/kWh prices are sensitive to the overall size of jurisdiction, and

---

[278] FERC Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No. PL04-15-000. October 2004.

provided a separate estimate for smaller jurisdictions of $0.5 per MWh (or $0.67/MWh in 2018 dollars).[279]

5.4.3.2 Estimate of Operational Costs in Hawaii

The degree to which IGO costs are fixed or scalable with jurisdiction size is uncertain. If IGO costs are completely fixed and not responsive to jurisdiction size, we would expect the lower end of the cost range provided by FERC ($67 million in start-up costs and the same amount in operational costs each year, in 2018 dollars) to apply to Hawaii. However, if IGO costs may be scaled based on the size and complexity of a jurisdiction, Hawaii may experience a much lower IGO implementation cost. Based on the "small jurisdiction" per-MWh cost identified by FERC, and the Project Team's forecast of 11.9 TWh in annual electricity sales in Hawaii, this would yield both a start-up cost and an annual operational cost of $8.0 million. This wide range in potential reflects the uncertainty and many possible implementation pathways of a potential IGO model in Hawaii.

5.4.4 Conclusions on Steps and Costs of Creating and Operating an IGO

Although existing ISOs are quite different in situation and scale from any potential IGO in Hawaii, it is clear that an ISO or IGO is created as a separate entity purposed with managing the dispatch and planning functions of both the transmission and distribution assets on the grid. Based on the processes undertaken to create other ISOs on the US mainland, the Project Team concludes that in order to develop an IGO, the HECO Companies and KIUC must voluntarily agree to create a separate entity that would function as the IGO, or the state would need to compel the creation of the IGO through legislation. If the legislation is sought by the PUC, it is likely that the PUC would conduct an investigatory proceeding prior to working with legislators to draft a bill. Following the creation of the entity, the utilities would have to turn over transmission operations to the IGO. Due to Hawaii's exclusion from FERC jurisdiction of interstate transmission (among other things), Hawaii's IGO would not need to file tariffs or otherwise apply to become an ISO with FERC.[280]

In terms of timeline, the process of creating an ISO dated from the initial decision to create an IGO to its initial operation takes approximately one-and-a-half to two years.[281] This timeline was

---

279 However, as noted in the discussion of HERA costs, the size of FERC's "small" jurisdiction is still approximately 10 times higher than Hawaii's electric grid.

280 Precedent for this comes from ERCOT, which similarly is excluded from FERC's jurisdiction. ERCOT became an ISO at the direction of the state, not FERC. *See* Tom Hunter, History of Electric Regulation in ERCOT, Public Utility Commission of Texas, April 17, 2012, https://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf at 10.

281 See, ERCOT, "History," http://www.ercot.com/about/profile/history; and Texas Legislature Online, "history," https://capitol.texas.gov/billlookup/History.aspx?LegSess=74R&Bill=SB373, which indicates that in June 1995 the Texas legislature voted to deregulate the wholesale generation system and began the process of expanding ERCOT's responsibilities. Then on August 21, 1996, ERCOT became the first ISO in the United States. See also, New York Independent System Operator, Introduction to the NYISO, July 21, 2011, available

generally consistent among the jurisdictions considered in this report, even when circumstances varied. For example, in New York and Texas, this timeline may have been affected by the fact that the ISO responsibilities and title were assigned to existing entities that already performed many of the same functions, whereas in California, legislation created a brand-new entity. All three jurisdictions are quite large and contain at least several utility companies.

Despite this clear trend in timelines for creation of an IGO, when contemplating establishing an IGO in Hawaii, it is also important to note any factors that may cause the timeline to vary. Specifically, it will be essential to consider the fact that there is no existing entity that could assume the responsibilities of the IGO and thus, a new entity will be required. Additionally, the size of the transmission grid and the number of utilities involved in Hawaii are much smaller than in other jurisdictions. Either of these considerations could cause the timeline to be slightly longer or shorter than two years in duration.

Costs were difficult to predict based on the difference in size and scalability of a national model to a single jurisdiction, and in particular, one as small as Hawaii. However, the Project Team estimates that it would cost at least $8.0 million to start-up an IGO in Hawaii (and the same amount in annual operational costs) based on a comparison to the costs of similar (but larger) organizations on the mainland.

5.4.5 Legal Considerations for an IGO

Based on the assessment of several existing ISOs above, it seems clear that the ISO or IGO can either be created voluntarily by the utility companies or by the state through legislation. The utility companies in New York and Texas voluntarily created the predecessor entities to their ISOs in response to some extraordinary event. In New York, the utilities created the NYPP after realizing the importance of an interconnected grid following the Northeast Blackout of 1965. In Texas, the utilities came to a similar realization after their efforts to support the country during World War II. Then, during the deregulation of the energy market in the late 1990s, New York created NYISO as a method of complying with FERC Order 888.

In contrast, Texas adjusted the corporate structure and purpose of ERCOT to be an ISO on its own initiative. Since Texas is not part of FERC's jurisdiction for this purpose, ERCOT became Texas' ISO through initiatives of the state and was not subject to FERC approval. California's ISO was created by the legislature and, like NYISO and other ISOs besides ERCOT, was submitted to FERC

---

at: http://www.nyiso.com/public/webdocs/markets_operations/committees/councils/consumer_advisory_council/Introduction_to_the_NYISO.pdf at 3, showing timeline in which NYPP files NYISO proposal in 1997, and NYISO begins operations on Dec. 1, 1999. Finally, see, FERC, "California Independent System Operator Corporation (California ISO)," https://www.ferc.gov/industries/electric/indus-act/rto/metrics/caiso-rto-metrics.pdf, and California Assembly Bill No. 1890, September 23, 1996 (Stats. 1996, c. 854 (A.B. 1890), § 10, eff. Sept. 24, 1996) (codified in part, e.g., as West's Ann. Cal. Publ. Util. Code § 330).which show that CAISO began full transmission operations in March 1998, about 1.5 years after CAISO was created in September 1996.

as compliance for FERC Order 888. Unlike NYISO, CAISO is influenced by the state (rather than being independent) in its operations.

Hawaii's situation is quite different from New York, California and most other states because its grid is not connected to the grid of any other state and therefore does not engage in interstate transmission. In this way, it is similar to ERCOT because the grid isolation excludes Hawaii from FERC regulation of electricity transmission. Hawaii's situation is also different from the other jurisdictions because the state has so few utility companies in its jurisdiction. Aside from KIUC on the island of Kauai, Hawaii's grid is primarily owned by one utility company (HECO, HELCO, and MECO are all subsidiaries of Hawaiian Electric Industries). Therefore, it seems unlikely that the HECO Companies would voluntarily create a separate entity to manage fairness and grid operations when it currently is the exclusive owner of the grid on all islands except Kauai. Additionally, it seems unlikely that the HECO companies would voluntarily give up transmission responsibilities. Based on these assumptions, the Project Team focuses this legal analysis on the State's authority to create an IGO entity.

5.4.5.1 State of Hawaii's Authority to Create an IGO

Hawaii does not currently have an existing legal framework for the IGO regulatory model. As was discussed in Section 4.3.3, state law grants the PUC broad supervisory and investigative authority, which it could use to initiate proceedings related to IGO issues. Additionally, as discussed in Section 5.2.7, the PUC also has the authority to create HERA, which could perform some of the reliability functions that the IGO would perform. Thus, although the PUC would likely have the power to implement some components of the IGO model through its current general supervision, investigation, and ratemaking authority, legislation may be needed to clarify the PUC's authority over the new IGO entity, and as a practical matter, to encourage the PUC to proceed with this course of action if it is deemed in the best interest of Hawaii.

In light of the above considerations, the Project Team has identified several paths the State of Hawaii could take to establish an IGO based on past experiences by the State. Each of these pathways require legislation, and it is unlikely that any of the paths or legislation will create an entity that is truly independent of state influence. However, complete independence of the IGO in Hawaii may not be problematic. While the ISO standard of FERC lists independence as a critical element of the ISO, it is true that both the Texas ISO and the California ISO are influenced by their States. As was discussed above, CAISO was created by the California legislature and its board is appointed by the governor. Although FERC theoretically could revoke CAISO's ISO status for failure to comply with the ISO standards, it hasn't done so yet.[282] In Texas, ERCOT is regulated by the Texas Legislature and the Texas PUC, and this is acceptable because ERCOT is not subject to FERC regulation for these matters. Because Hawaii is also not subject to FERC regulations, the matters of strict independence of the IGO are likely less important from a legal standpoint as they

[282] "FERC has the authority not to accept something which it does not deem an ISO. It does not have the authority to reform and regulate the governing body of a public utility under the theory that corporate governance constitutes a "practice" for ratemaking authority purposes." *California Independent System Operator Corporation v. FERC*, 372 F.3d 395, 404 (DC Cir. 2004)

are in FERC regulated jurisdictions. However, the IGO created will be subject to PUC regulation, and presumably, the PUC will help to keep the IGO independent to the extent necessary for the IGO to accomplish its duties.

5.4.5.1.1 Reapportion utility transmission fees to third-party administrator

One method the state could use to create an IGO is to reapportion utility transmission fees currently paid to the utilities to a third-party administrator that would be contracted by the PUC. The third-party administrator could effectively be the IGO, with funds directed to support the fair and independent management of the transmission grid.

The precedent for this strategy comes from the Public Benefits Fee law,[283] which arose from the Consumer Advocates recommendation for such an initiative and third-party administrator in HECO's demand-side management and energy efficiency proceeding (Docket No. 05-0069).[284] The law was first legislated in 2006 and refined in the 2008 session. The law gave the PUC the authority to change the market structure of energy efficiency programs by appointing a third-party administrator to implement the energy efficiency programs. This adjusted design was an attempt to "remove the perceived inherent conflict between a utility's desire to generate revenues and income, and energy efficiency measures that serve to decrease sales and defer the need for additional plant investment" and also was intended to provide better facilitation of those programs at a greater cost efficiency.[285] The third party administrator would be funded by the Public Benefits Fee (or Public Benefits Fund) that itself was funded by an energy bill surcharge.[286]

The third party administrator would be chosen by and respond to the PUC but is not deeded a "governmental body" so long as the fees collected by the administrator were comprised solely of the public benefit fees under the statute.[287] Following the initial creation of this law, the PUC opened an investigative docket "to examine the issues and requirements raised by, and contained in, Part VII of Chapter 269, Sections 269-121, et seq., HRS about Hawaii's Public Benefits Fund."[288]

Additionally, the docket sought to use the proceeding to select a Public Benefits Fund Administrator and implement a new market structure for Energy Efficiency Demand-Side

---

[283] Haw. Rev. Stat. §§ 269-121-125.

[284] About the Division of Consumer Advocacy, 2007, http://www.hawaiienergypolicy.hawaii.edu/outreach-communication/legislative-briefings/_downloads/2007-division-consumer-advocacy-awakuni.pdf at 5

[285] Chris Ann Dickerson et al., Aloha E Komo Mai: Hawaii Introduces its New Energy Efficiency Program Structure (ACEEE 2010), available at https://aceee.org/files/proceedings/2010/data/papers/2077.pdf at 54-55, quoting the bill (original text of the act including its purpose was not available online).

[286] Haw. Rev. Stat. § 269-121

[287] Haw. Rev. Stat. § 269-122

[288] Hawaii Public Utilities Commission, Order No. 23681, Docket No. 2007-0323, issued September 26, 2007.

Management.[289] In 2009, Leidos, then known as Science Applications International Corporation ("SAIC"), was awarded the contract with the PUC to be the program administrator of Hawaii's energy efficiency programs.[290] The docket is still open as the means to set the public benefits fee budget and fee surcharges.

This particular method to create a new entity appears to be a good fit for creating an ISO because it also removed a responsibility from the utilities and created a new funding mechanism and entity to overtake that responsibility. Although the PUC was involved in the implementation and regulation of the third-party administrator, it is technically considered a non-government body. Based on the success of this program, it is reasonable to conclude that the PUC and the legislature could take a similar approach to divesting the utilities of transmission and distribution management operations.

5.4.5.1.2 Creation of a new agency, corporation, or instrumentality of the State

Another method the state could use to create an IGO is to establish a new state agency or instrumentality of the state via legislation. A good example of this is the Hawaii Green Infrastructure Authority ("HGIA"). HGIA and the Hawaii green infrastructure loan program were created in the 2013 Hawaii Laws Act 211, which was codified as HRS §196-61 et seq. The purpose of the act was to "establish a regulatory financing structure that authorizes the [PUC] and [DBEDT] to acquire and provide alternative low-cost financing, to be deployed through a financing program to make green infrastructure installations accessible and affordable for Hawaii's consumers, achieve measurable cost savings, and achieve Hawaii's clean energy goals."[291]

For administrative purposes, HGIA is within DBEDT and is "an instrumentality of the State comprising of five members. More specifically,

> *The director, the director of finance, and the energy program administrator of the department shall be members of the authority. The governor shall appoint the other two members, pursuant to section 26–34. The director shall be the chairperson of the authority. The authority shall be placed within the department for administrative purposes, pursuant*

---

[289] *Id.*

[290] In 2012, SAIC split into two companies. SAIC spun off into its own company, and the parent company rebranded itself as Leidos. https://www.washingtonpost.com/business/capitalbusiness/one-year-later-saic-and-leidos/2014/09/26/d1fefd68-4273-11e4-b437-1a7368204804_story.html?noredirect=on&utm_term=.8c2d57f8b7fa

Leidos has continued to operate the Hawaii Energy Program, most recently securing another potential nine-year contract in 2016. https://blog.executivebiz.com/2016/07/leidos-awarded-85m-hawaii-energy-conservation-program-mgmt-extension/

[291] Hawaii Session Laws, Act 211, June 27, 2013 (S.B. 1087 CD1), available at: https://www.capitol.hawaii.gov/session2013/bills/SB1087_CD1_.htm

> *to section 26–35; provided that until the authority is duly constituted, the department may exercise all powers reserved to the authority and shall perform all responsibilities of the authority.* [292]

The program operations are funded by revenue bonds issued by DBEDT, while the bonds issued by GEMS are paid for by a PUC-approved Green Infrastructure Fee on utility bills.[293] The HGIA developed and operated the green infrastructure financing program, known as GEMS,[294] which was designed to make clean energy improvements affordable and accessible for a broader cross-section of Hawaii ratepayers. Although the HGIA and the GEMS program operate within DBEDT for administrative purposes and are subject to PUC approval,[295] they were created for a specific purpose and effectively operated as a separate entity.

The creation of the HGIA and GEMS program illustration another method by which the state was able to adjust the regulatory process by creating a new entity. As with the previous example, this method has been successfully[296] implemented in Hawaii, indicating the existence of legal authority for a similar effort in terms of creating an IGO. Additionally, due to Hawaii's independence from FERC regulation, the Project Team anticipates that state interaction with the IGO will not be problematic, although less interference would likely result in a more effective IGO.

[292] Haw. Rev. Stat. 196-63

[293] GEMS, FAQs, http://gems.hawaii.gov/learn-more/faqs/

[294] GEMS stands for Green Energy Market Securitization Program. *Id*.

[295] The HGIA/GEMS public filings, including the approval of the GEMS program and annual plan approvals, are contained in Docket No. 2014-0135.

[296] The Project Team notes that success here refers explicitly to the implementation process.

6 Conclusion on Steps, Timeline, Costs, and Legal Framework

This report has explored the steps, timelines, costs, and legal considerations required for the implementation of the various elements of the three regulatory models proposed for the State of Hawaii. This section of the report brings the elements together under each proposed regulatory model, to provide an overview of the steps, timeline, costs, and legal considerations required for each regulatory model. Following the summary of each regulatory model, this section highlights some of the key considerations in concluding thoughts.

6.1 Summary of the Steps, Timeline, Costs, and Legal Framework for Each Model Considered

In Task 2.2.6, the Project Team identified three regulatory models for further consideration in this analysis. These regulatory models were (1) Outcomes-based PBR; (2) Conventional PBR with Light HERA; and (3) a Hybrid Model that included a combination of Outcomes-based PBR with DSPP and an IGO. This report considered the various elements of each regulatory model separately due to the presentation of and availability of resources for comparison, but now assesses each model as a sum of its component parts.

6.1.1 Outcomes-based PBR

Based on the estimates included in Sections 4.1 and 5.1, above, Hawaii's timeline for implementing Outcomes-based PBR would still be 21 months dated from the Order initiating an investigative docket on PBR to the legislature's January 1, 2020 deadline to implement PBR as the regulatory model for the state. It is feasible for Hawaii to meet this 21-month timeline, particularly if the PUC is able to efficiently and effectively design a review and approval process for utility companies' PBR plans that builds upon the existing PBR mechanisms. However, it should be anticipated that the PUC may require additional time to fully implement the new regulatory model. This is particularly true if the PUC were to implement a more complex Outcomes-based PBR model. If the design of specific mechanisms or the process of working with stakeholders and utility companies run into any challenges or delays, which is quite likely for such a complex model (especially in its first iteration), the timeline for the ultimate transition could be delayed, extending beyond 21 months.

The specific steps and timeline for implementing an Outcomes-based PBR model in Hawaii are likely to be similar to the steps and timeline used for PBR in general.[297] Again, although this process has taken up to approximately 30 months in RIIO, the process could be shortened through political will and efficiency and use of simpler mechanisms (especially during the first generation PBR), or could be lengthened depending on the depth and complexity of the Outcomes-based PBR model that is chosen.

During the course of 21 months, the PUC generally should 1) state its intent to transition to PBR and release a schedule, 2) engage in Stakeholder education and outreach, 3) publish the guiding

---

[297] See Section 4.1, supra.

principles to be used and the stakeholder feedback already procured, 4) finalize the PBR guiding principles and framework, 5) commence an independent study to help develop specific mechanisms and PBR components, 6) conclude and submit results of the independent study, 7) require utilities and other interested parties to submit their PBR proposals, 8) admit intervenors, respond to information requests, conduct oral hearings and receive submitted arguments by utilities and other intervenors, and 9) issue a final PBR decision.[298] This process also broadly reflects the process proposed and begun by the PUC.

Costs of implementation are calculated within a range that is based on the overall cost increase experienced by the AUC in its three-year transition, and one based on the percentage change (10.9%) in costs. This approach yields an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation of subsequent PBR terms.[299]

The legal requirements for Outcomes-based PBR are satisfied with the existing legal framework.[300]

6.1.2 Conventional PBR + Light HERA

The steps and timeline for implementing Conventional PBR + Light HERA require a combination of the steps and timeline contemplated for PBR in general and HERA.

The Conventional PBR process is also represented by the general PBR process, described in Section 4.1.3. During the course of 21 months , the PUC should follow the 9 steps listed in Section 6.1.1, above. At the time of this writing, the PUC is in step 3 of this process, having held two technical workshops and has begun receiving regulatory assessment briefs from the parties.

In addition, the PUC will have to open a docket to investigate the design of and eventually implement HERA. Based on other investigative dockets in the PUC, this process may take approximately 2 years to complete and involves 1) opening the docket, 2) conducting the docket proceedings (e.g., motions to intervene, motions for additional information, briefs from the parties and intervenors), 3) issuing the decision and order regarding conclusions on the docket, and potentially 4) address any outstanding issues set forth in the decision and order.

Ideally, the PUC would conduct both processes simultaneously, so that the full implementation of this proposed model would occur within the longer PBR timeline of 33 months. If the PUC

---

[298] See Section 4.1.3, supra.

[299] See Section 4.2.3, supra.

[300] See Section 4.3, supra

were to conclude its PBR proceedings before initiating the HERA docket, the entire process would take close to five years for full implementation of the model.

Costs to implement the Conventional PBR + Light HERA model involves the combination of costs anticipated for both PBR and HERA. Costs of implementation for Conventional PBR follow the costs for general PBR and includes an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation of subsequent PBR terms.[301] In addition, the Project Team estimated of the HERA model based on the funding requirements of NERC, a similar entity active in mainland North America. Based on a per-kWh scaling of organizational costs, HERA would require a start-up cost between $234,000 and $585,000, and between $480,000 and $1.2 million in annual funding.

The legal requirements for Conventional PBR and HERA are both satisfied by the existing legal framework.[302]

6.1.3 Hybrid Model (Outcomes-based PBR + DSPP + IGO)

The steps and timeline for implementing the Hybrid Model require a combination of the steps and timeline contemplated for Outcomes-based PBR, a DSPP and an IGO. To reduce volatility from too many regulatory changes at once, the Project Team envisions a staggered implementation timeline, with the Outcomes-based PBR component being implemented in 2020, IGO established in 2023, and DSPP operations beginning in 2028.

During the course of the 21 months anticipated for Outcomes-based PBR to meet the January 1, 2020 deadline, the PUC will have to follow the steps detailed in Section 4.1.3 and summarized in Section 6.1.1, above. This process also broadly reflects the process proposed and begun by the PUC. The PUC would also need to operate with great efficiency and expediency and possibly choose simpler PBR mechanisms that would not require additional studies.

Costs of implementation are calculated within a range that is based on the overall cost increase experienced by the AUC in its three-year transition, and one based on the percentage change (10.9%) in costs. This approach yields an effected range in the estimated cost impact of between $683,000 and $2.78 million (in 2018 USD) per year over a three-year transition period. This results in a total transition cost of between $2.0 million and $8.3 million. The Project Team also anticipates costs to return to pre-transition levels following the transition, even during the implementation

[301] See Section 4.2.3, supra.

[302] See Section 4.3and Section 5.2.1, supra.

of subsequent PBR terms.[303] The legal requirements for Outcomes-based PBR satisfied by the existing legal framework.

Following the implementation of Outcomes-based PBR by January 1, 2020, the PUC and the legislature will need to work to create an IGO. This process would require writing and passing legislation authorizing the IGO, as well as a PUC docket to investigate the best design for an IGO and/or to function as a proceeding to regulate the IGO. This process of developing an operational IGO is estimated to take one-and-a-half to two years to complete. The costs are estimated to be at least $8.0 million in startup costs and the same amount in annual operation costs, based on a comparison to mainland organizations, though it is possible for costs to be substantially higher if organizational costs cannot be effectively streamlined to suit Hawaii's smaller geographic area. As mentioned above, new legislation will be required to create this entity, although there is a precedent for such legislation in Hawaii's legislative history.

After the IGO is operational (and perhaps before), the PUC would need to work on transitioning the utilities to assume the roles and responsibilities of DSPPs. This process, in particular, is very complex, time-consuming, and collaborative between all the parties, so it is helpful and more realistic for the implementation timeline to be set at 2028. The Project Team estimates using a relatively normal docket proceeding process to develop the DSPP, but notes that the proceeding will contain more participants, more issues to resolve, and greater complexity of creating and integrating the various mechanisms created. The Project Team estimates a timeline of approximately three years to have a policy and implementation plan for the DSPP developed, along with some mechanisms, at least. It is unclear how long the full implementation will take, although the Project Team anticipates that 2028 is an achievable target.

The costs for implementing the DSPP are estimated at $51.4 million, spread over three years (for an annual cost of $17.1 million in the three-year start-up period). Following this period, the Project Team estimates a $1 million annual operating cost. These figures are based on the costs and budgets of pilot projects currently active in New York State, but are subject to substantial uncertainty given the novelty of the DSPP model. The Project Team concludes that there is legal authority for the PUC to require the utilities to transition to include in their business models the DSPP model. However, due to the novel nature of this regulatory model and Hawaii's tendency to authorize or incentivize PUC actions via legislation, the Project Team recommends creating a statute that would explicitly authorize DSPP should this path be chosen.

6.2 Concluding Thoughts

The PUC has broad legal authority to implement regulatory changes that are in the public interest and that advance state energy goals. In particular, the PUC clearly has the legal authority to implement changes to the regulatory scheme that would result in both or either a PBR (outcomes-based and conventional) or HERA regulatory model. For PBR and especially HERA, this authority is supported by legislation explicitly requiring or authorizing each regulatory shift. The existing legal authority likely extends to the creation of a DSPP model, because such a shift would

[303] See Section 4.2.3, supra.

be an extension of normal regulatory operations. However, due to the novel nature of the DSPP model and the state's past precedence of creating legislation to support and explicitly authorize regulatory initiatives, the Project Team anticipates that such a regulatory change would likely require legislative support as a practical necessity if not a strict legal need. In contrast, the PUC does not appear to have the independent authority to implement an IGO. In the absence of voluntary utility-initiated efforts to create an IGO (which is unlikely), state efforts to establish an IGO would likely require state legislation similar to the processes undertaken to create ISOs in California and Texas.

In terms of timeline, the PUC is currently working under schedule to implement PBR by January 1, 2020. Based on a review of the timelines of similar past processes in other jurisdictions, the Project Team finds that this timeline is achievable if the PUC is able to manage the process with great efficiency and avoid some of the sources of delay that impacted regulatory shifts elsewhere. However, the Project Team anticipates that delay (of roughly up to one year, based on Alberta's timeline) may be necessary to provide the PUC with adequate time to fully consider the issues associated with the new regulatory model. The timeline to create the other elements of the regulatory models also require diligence but are not bound by a strict deadline as PBR is. The estimated timeline for HERA completion is approximately two years. The estimated timeline for legislating and creating an IGO is also approximately one-and-a-half to two. The DSPP model requires significant development of different regulatory mechanisms and interaction with the utility companies to develop the DSPP, so the timeline for implementation is likely to be much longer than the other models. In New York, the process has already taken approximately four years and still in progress. Although Hawaii probably would not take as long to implement DSPP due to its smaller grid size and fewer utility companies to work with, it is still likely to be a complex and time-consuming process that will take at least three years to complete.

Cost estimates are deeply uncertain, particularly for models such as DSPP and IGO, with a key factor being the size of Hawaii's grid. Many of the existing efforts to create these regulatory models have not been implemented on a grid size as small as Hawaii's, which makes the process of estimated transition costs inherently difficult and uncertain. Nevertheless, based on our analysis, the costs to establish the DSPP is $17.1 million during the three-year start-up period and $1 million in annual operating costs thereafter, while the costs to establish an IGO is between $8 million and $67 million in startup and annual operating costs, depending on the method of calculation. These cost calculations are discussed in detail in Sections 5.3.4.2 and 5.4.3.2, respectively.

7 Risk Analysis

The risks associated with the Status Quo regulatory model highlight some of the reasons why the State of Hawaii is considering a regulatory change. The COS regulatory model currently in use in the State of Hawaii provides a tacit incentive to the utilities to maximize shareholder returns by increasing the rate base and making capital investments. This incentive structure creates the risk of a negative impact on ratepayers, who may be required to pay higher rates based on the cost of increased capital investment. Thus, under this model, there is a clear tension between the interests of ratepayers and utility shareholders. The current regulatory approach also allows for some misalignment between state policy objectives and utility incentives, as the utility is not given a direct financial incentive to achieve state policy objectives (save for the limited use of performance incentives related to reliability and other factors). For example, the current regulatory approach offers limited financial incentives for utilities to pursue increased DER penetration.

Additionally, while ratepayers bear the burden of some critical risks in the short term (i.e., higher rates, impacts associated with failure to meet state energy goals), the utility shareholders may be exposed to dire risks such as grid defection in the long term. Grid defection is a particularly severe risk because it is nonlinear: as more customers leave the grid (likely due to the high costs or misalignment of incentives for them to stay on the grid), the higher the cost becomes for remaining customers. The higher costs for remaining customers then make grid defection seem more attractive and feasible to those remaining customers and compounds the grid defection. Although electricity usage is decoupled from utility revenues in the State of Hawaii, a dramatic decrease in the number of ratepayers that support large fixed costs is still likely to have serious negative repercussions for stakeholders. The alternative models proposed in this report offer potential solutions to the problems that arise from the continued use of the Status Quo. For instance, all the alternative models contain a form of PBR, which is purposefully designed to incentivize performance rather than capital investment. However, each of the alternative models come with their own risks, in part because of the additional complexity that they introduce into regulatory structures.

With this perspective, we assess and compare the various sources of financial and operational risks for different stakeholders (ratepayers and utility shareholders) under each regulatory model. During this exercise, we also assign a likelihood and risk impact rating for each risk under each regulatory model, and both the potential impact of the risk category and the likelihood of each risk are evaluated in tandem to assess the overall risk to the ratepayers and shareholders in each category. In our assessment of the potential impacts of the risks, we assess the risks in terms of how they may impact the issues that ratepayers care about (low-cost energy, reliability, access to renewables, etc.) and the issues that shareholders care about (returns and utility financial stability). This analysis does not attempt to score the total overall risk of each regulatory model, but instead identifies areas in which a particular regulatory model may have comparatively higher or lower degrees of risk than another.

Additionally, we note that this analysis primarily focuses on the risk categories as they relate to the HECO companies (particularly for shareholder risks, since the HECO companies are a traditional investor-owned utility). However, we do briefly discuss how KIUC could be impacted by the risks, as applicable throughout the report. As KIUC is a cooperative utility, however, the Project Team does not make a distinction between ratepayers and shareholders.

7.1 Methodology

The Project Team has identified four regulatory models – Status Quo, Outcomes-based Performance-based Regulation ("PBR"), Conventional PBR with Light HERA, and a Hybrid Model that combines Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Independent Grid Operator ("IGO") – for further analysis, including this assessment of risks associated with the different models.[304] In addition, the Project Team applied the risk assessment to the regulatory model of Lighter PUC Regulation, although this scenario only applies to KIUC on Kauai, and is denoted with an asterisk in each table. Each model was assessed against a set of eight risk factors related to a series of regulatory, financial, and operational factors. For each risk category, we describe who is bearing the respective risk, and what can be done by different stakeholder groups (e.g., ratepayers, utility, regulators) to mitigate that risk. The final results are illustrated in an accompanying matrix, included in Figure 11. Note that the category "shareholder severity" is listed as "N/A" for all risk categories for the Lighter PUC Regulation for KIUC, as KIUC is a member-owned cooperative with no distinction between ratepayers and shareholders.

More specifically, for each regulatory model, all risk factors were assigned a qualitative risk rating and separate impact ratings for ratepayers and shareholders. The qualitative risk and impact rating schemes have five tiers: Low, Low-Medium, Medium, Medium-High, and High. In the tables for each regulatory model and the summary table of all the risks, the rating scheme is represented in the following way:

H – High Risk/Impact
MH – Medium/High Risk/Impact
M – Medium Risk/Impact
LM – Low/Medium Risk/Impact
L – Low Risk/Impact

Additionally, the risks were categorized by phase and type. The phase of the regulatory model distinguishes between risks that occur during the transition to an alternative regulatory model and the operation of the regulatory model. The type of impact highlights whether the risk impacts the utilities finances or their operations.

The actual risk rating reflects the relative *likelihood* that the risk factor could take place (i.e., the likelihood that the regulatory design would be more expensive than anticipated), while the impact rating reflects the relative *magnitude* the outcome would have on the utility if it took place (i.e., how impactful the extra, unanticipated expense of the regulatory model would be to the

---

[304] The recommended models for KIUC are (1) HERA, (2) IGO, and (3) lighter PUC regulation. These recommended models for KIUC are not the focus of this report, but discussed as applicable.

ratepayers and the shareholders). In some cases, but not all, the risks can be mitigated with various strategies.

7.2 Factor Results and Discussion

This section details the various risks projected for the implementation and operation of the regulatory models considered in this report. Specifically, each risk section first provides a summary table of the likelihood and magnitude of the risk across the four regulatory models and identifies the phase and type of risk being considered. Then the Project Team provides a discussion of the details of the risk as it applies to each regulatory model.

7.2.1 Cost and Complexity of Regulatory Approach

The following section discusses the risks related to the costs and complexity of the regulatory approach. These potential risks are important for the State of Hawaii to consider as it navigates the challenging task of choosing an appropriate regulatory model for the State's electric utilities to mitigate the larger risks of maintaining the Status Quo regulatory model. The complexity of the regulatory approach and the ability to accurately estimate costs have a great impact on whether the State would be able to implement a particular regulatory model or could afford to implement and operate it. This section aims to provide some guidance on this topic.

7.2.1.1 Regulatory Cost Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	LM	L
Outcomes-based PBR	MH	MH	LM
Conventional PBR + Light HERA	M	M	LM
Hybrid Model	H	MH	LM
Lighter PUC Regulation*	LM	LM	N/A

Relevant Phase: Transition
Type: Financial

The potential Regulatory Cost Risk is the lack of clarity on the ultimate expense to the Commission or other actors of the implementation and ongoing use of alternative regulatory models, despite research and analysis into the subject. This uncertainty exists in particular because there is not an example of comparable size or market structure from which to draw conclusions for most regulatory alternatives. Whereas the State of Hawaii is a relatively small jurisdiction with a monopoly vertically integrated IOU provider that serves approximately 95% of the State's population and a cooperative on the Island of Kauai (serving the remaining ~5%), other jurisdictions that have implemented forms of the regulatory models considered in this report are considerably larger in size and consist of more than one or two utility companies. The inability to draw direct comparisons creates uncertainty in the ultimate costs of transitioning to alternative regulatory structures.

This potential risk is distributed differently across the four models. In the Status Quo model, there is a very low immediate regulatory cost risk because the model is currently in operation in the State of Hawaii. Therefore, the costs of transition are currently not necessary, and the costs of operation are well-known. However, it is possible that under the Status Quo model the issue of changing the regulatory model could be raised again in the future to improve the state's ability to meet its own goals. Because the regulatory cost risk is for the transitional phase, and because we use the Status Quo more as a base-level for reference in this report, for the purposes of this analysis we ascribe relatively little weight to such future potential events in this model, as described in Section 0, above. We assign a Medium-High likelihood that the transitional and operational costs will be more than anticipated for the Outcomes-based PBR model due to the complexity of the PBR model, and a Medium likelihood of the same for the Conventional PBR with Light HERA models. This is due to some uncertainties in the PBR model (noting that Conventional PBR is less complex than Outcomes-based PBR) combined with some uncertainty about whether Light HERA will incur implementation and operational costs and complexities without commensurate benefits. For the Hybrid model, there is a High likelihood that costs will be higher than anticipated due to the greater complexity of the model and its component parts (Outcomes-based PBR + DSPP + IGO) and the existence of fewer models with which to compare. The Project Team also considers the risks for this model to be the highest due to the uncertainty of DSPP revenues, as well as the novelty of the DSPP regulatory structure, which has not been fully implemented in any jurisdiction.

This analysis primarily considers uncertainty in the costs of regulating new models, and the Project Team assumes that the organizations that would incur these costs (such as the Hawaii PUC, HERA, or an IGO) would ultimately seek to recover any cost overruns from ratepayers. Therefore, the Project Team considers this risk category to be potentially more severe for ratepayers than for utility shareholders. During the transition to the alternative models, the Project Team anticipates a Medium-High level of severity of the risk to ratepayers under Outcomes-based PBR and Hybrid model, and Medium severity of risk to ratepayers under the Conventional PBR with Light HERA model (as the team expects the regulatory costs of these models to be more predictable). Meanwhile, we expect shareholders to be less affected by higher than anticipated costs, with Low-Medium rankings across the models. The differences in the severity of the risk on ratepayers versus shareholders is attributed to the fact that costs are more easily and more likely to be passed onto ratepayers than shareholders.

The potential Regulatory Cost Risk could be mitigated both by working to create cost forecasts from the best available data, as this report aims to do, as well as by closely managing costs as they arise to the extent possible.

While this analysis primarily concerns risks for counties served by the HECO Companies, similar risks may be expected in Kauai. The Project Team expects the IGO model to provide the greatest risk for cost uncertainty, as it a more complex model than HERA. Lighter PUC regulation would be expected to provide a net reduction in costs both for the PUC and for KIUC, though there is a risk that savings may not be as substantial as intended.

7.2.1.2 Regulatory Complexity Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	M	M
Outcomes-based PBR	M	MH	M
Conventional PBR + Light HERA	M	MH	M
Hybrid Model	H	H	H
Lighter PUC Regulation*	L	L	N/A

Relevant Phase: Transition + Operation
Type: Operational

Any change in regulatory approach is subject to some degree of complexity, and in this case, each of the models assessed entails a greater degree of complexity than traditional COS regulation. This added complexity creates a potential risk for ratepayers and shareholders alike because as complexity in regulatory models increases, so does the likelihood for unintended consequences. As with Regulatory Cost Risk, Regulatory Complexity Risk exists in part because of the unavailability of an example of comparable size or market structure against which to compare to the State of Hawaii's regulatory scene. The inability to draw direct comparisons creates uncertainty in our assessment of the ultimate difficulty of the process to design and implement the alternative models and to operate them.

The potential risk of Regulatory Complexity varies across the different regulatory models considered. In the Status Quo model, there is Low regulatory complexity risk – while the rate case process used to consider utility costs and set rates under the COS model is not without its difficulties, these complexities are known and manageable in the State of Hawaii. We assign a Medium likelihood of risk for the Outcomes-based PBR and the Conventional PBR with Light HERA models. We consider Outcomes-based PBR to lead to substantially more complexity than the Conventional PBR model, due to the challenge of defining and tracking metrics that would inform the regulatory process. However, also incorporating HERA does increase the complexity of the second alternative regulatory model, as the process of defining roles and responsibilities across utilities, the PUC, and the new HERA entity may lead to additional complications. We consider the Hybrid model to be the most complex of the three alternative models, as it combines Outcomes-based PBR with two additional and complex regulatory concepts, an IGO and a DSPP. In addition to the complexitiy of adequately defining PBR outcomes and metrics to align utility incentives and policy objectives, creating the IGO will also entail the complexity of developing efficient market rules and obtaining PUC approval, as evidenced by existing ISOs frequently adjusting their rules. Furthermore, customers and market actors may have difficulty operating efficiently within the rules of a DSPP, which could lead to low participation in the process. The DSPP is also untested, which means there is uncertainty regarding the source and magnitude of the actual business model and revenue streams. Finally, the Hybrid model could also include the difficulty of integrating all three elements into a single efficient and effective regulatory model. As was true for Regulatory Cost Risk, the Hybrid model also carries a higher level of regulatory complexity risk because a similar hybrid model has yet to be fully implemented by any other jurisdiction, so it is difficult to determine how challenging such an implementation will be.

The Project Team anticipates a Medium-High level of impact severity for ratepayers and a Medium level of impact severity for shareholders for both the Outcomes-based PBR and Conventional PBR with Light HERA models. This is because the ability of the models to function properly will have a more significant impact on ratepayers (i.e., poor service, high rates) than it will on shareholders, although shareholders will also be impacted because revenues under either PBR method are based on the utilities ability to meet performance targets. Due to the greater inherent complexity of the Hybrid model, the Project Team anticipates a High level of impact severity for ratepayers. And due to the structure of the Hybrid model, in which revenues (and therefore, cash flows to shareholders) are affected by whether the utilities are able to meet their performance targets (earnings through PIMs) and whether the DSPP component enables sufficient market activity for additional revenues, we also anticipate a High level of impact severity for shareholders.

The potential risk of Regulatory Complexity could be mitigated by working to estimate the complexity of the models to the extent possible, as this report aims to do. This risk could also be mitigated by closely monitoring the progress of the design, implementation, and operation of the models with careful attention to when complexities begin to create problems and addressing those issues as quickly as possible. Finally, in the case of and the Conventional PBR with Light HERA model, and the Hybrid model models, this risk could be mitigated by phasing the implementation of different regulatory components, or by implementing certain elements on a pilot basis (such as how New York state has used pilots to test the implementation of various components of the DSPP model).

Regarding KIUC, the Project Team expects the IGO model to provide the greatest risk for regulatory complexity, as it is more complex than HERA. Lighter PUC regulation would be expected to provide a net reduction in complexity for both KIUC and the PUC, since KIUC would no longer need PUC approval for rates, contracts, and capital expenditures in most cases (PUC approval would still be required if rate increases and capital expenditures crossed a certain threshold).

7.2.2 Regulatory Approach Does Not Yield Desired Outcomes

This section discusses the risks related to situations in which the regulatory approach does not yield the desired outcomes. This includes the risks that rates end up higher and profits end up lower than anticipated by the regulatory model, or the risk that incentives and penalties featured in the regulatory models are inadequate in their design and operation to achieve desired results. These risks are important for the State of Hawaii to consider during its evaluation of regulatory models that would mitigate the larger risks of maintaining the Status Quo because they are likely to have real impacts on ratepayers and shareholders and could also impact the overall effectiveness of the chosen PBR model.

7.2.2.1 Rates Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	MH	MH	L
Outcomes-based PBR	M	MH	LM
Conventional PBR + Light HERA	M	MH	LM
Hybrid Model	M	MH	LM
Lighter PUC Regulation*	LM	MH	N/A

Relevant Phase: Transition & Ongoing
Type: Financial

The cause of the potential Rates Risk for high rates varies across the regulatory models. The Project Team notes that we are comparing rates among regulatory models, not in absolute terms. For example, one model can result in lower rates than another model, but that does not imply that rates will go down from current levels.

Under the Status Quo model, there is a risk that the Capex-based approach provides an implicit incentive for increased capital expenditures with rate-based recovery. For both PBR models (Outcomes-based and Conventional) that comprise the other regulatory models, there is a risk that the Totex approach may increase rates if the capitalization rate results in a faster increase of the regulatory asset base ("RAB") than the current (Status Quo) Capex approach. Under the Hybrid model, there is also a risk the IGO, which is envisioned as an entity that will lower power costs (and by extension, rates), will not function as intended, which could lead to higher rates.

Aside from the Status Quo model, the Project Team considers the potential Rates Risk of high rates to be consistent across the models in terms of likelihood and severity. For all three alternative models, the Project Team estimates a Medium level of likelihood that rates will be higher than anticipated, a Medium-High impact of high rates to ratepayers due to the uncertainty of how much rates would actually increase under these rate formulas in the PBR frameworks, and a Low-Medium impact on shareholders. The likelihood that rates will be higher than anticipated under that Status Quo model is considered to be Medium-High because of the aforementioned implicit incentive for utilities to increase capital expenditures to recover higher rates (though there are controls on utility capex expenditures through the existing regulatory process). As with the alternative models, for the Status Quo we assess any increase in rates as having a Medium-High impact on ratepayers. We assess this model as having a Low impact severity for shareholders because as compared to the regulatory alternatives there is a greater assurance of steady rates (and utilities' revenues) under the COS model.

The potential risk of high rates from the Status Quo model can probably be mitigated through effective regulation that scrutinizes utility expenditures that are recovered from ratepayers, or by moving the ratemaking procedure away from a Capex-based approach. Although the other regulatory models are designed to eliminate the Capex-approach of the Status Quo model, they also carry the risk that the Totex approach may not work as intended. The potential risk of high rates from the mal-design or performance of the Totex rate formula may be mitigated by carefully researching and designing the formula to the best extent possible, as well as closely monitoring and adjusting the inputs and outputs to correct any errors promptly.

While the above analysis concerns risk for counties served by the HECO companies, rate risks may also exist for KIUC customers. These are expected to lower than for the HECO ratepayers, however, as much of the above analysis considers the potential impacts of PBR on rates (which the Project Team is not evaluating for Kauai). Still, each regulatory alternative would carry some form of rate risk, due to uncertainty regarding how the HERA and IGO models would impact utility costs and rates, and due to uncertainty of how relaxed regulatory oversight may impact the KIUC rate-setting process.

7.2.2.2 Profit Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	LM	MH	H
Outcomes-based PBR	M	M	H
Conventional PBR + Light HERA	M	M	H
Hybrid Model	M	M	H
Lighter PUC Regulation*	LM	M	N/A

Relevant Phase: Ongoing
Type: Financial

Profit Risk is the potential risk that profits will be limited or will decrease as a result of the regulatory model in place. For the Status Quo model, profit risk is in some ways the converse of rate risk. In the short term, there is minimal profit risk under COS, as utilities can maintain a stable rate of return on capital investments. In the longer term, however, the threat of grid defection could constitute a profit risk under the COS model (while utility profits are decoupled from sales, in the long term the project team anticipates that increased rates of grid defection would be harmful to the utility's financial health and profits). Alternately, the utility is exposed to some profit risk if stricter regulations from the PUC could result in a reduction in the rate of return that utilities can claim on capital investments.

For the alternative regulatory models (Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid Model) the Project Team anticipates the Totex approach of either PBR model could limit shareholder returns relative to the Status Quo, and that revenue caps also could limit returns. Profit risk could also arise from either an incorrect design of the PBR formula, higher than anticipated regulatory costs, or a situation in which lower demand growth does not support the annual growth in the proposed Capex and Opex. For the Hybrid model, in particular, the profit risk could also arise if the DSPP design and increase of DER limit future expenses and revenues.

Aside from the Status Quo model, the Project Team treats the risk of limited profits or limited growth caused by lower demand as consistent across the models in terms of likelihood, the severity of impact to ratepayers, and severity of impact to shareholders. For all three alternative models, the Project Team estimates a Medium level of likelihood that profits will be limited by the regulatory models, a Medium level of impact to ratepayers (assuming that, in some cases, an impact on profits would eventually have an effect on rates in future PBR periods), and a High level of impact to shareholders. In terms of the Status Quo model, we estimate a Medium-High likelihood that profits will decrease under the model, a Medium-High impact of that profit decrease on ratepayers, and a High impact on shareholders.

Under the status quo, the likelihood of profit risk due to grid defection may be challenging to mitigate without a broad shift in regulatory or ownership model. Under the other models, the profit risk may be reduced by taking efforts to design the PBR formula and overall regulatory framework in the most appropriate way possible and to monitor the way the market functions once it is implemented, taking swift and careful action to make any corrections.

The Project Team assesses a low-profit risk for KIUC regulatory alternatives. KIUC, as a cooperative utility, is a non-profit entity, though profit risk may still be a relevant consideration as it relates to overall utility fiscal solvency. The Light PUC Regulation model could provide a modest risk of decreased profits/returns to cooperative members if KIUC were to become less successful without the guidance of PUC regulation for most issues. The reliability efforts created under HERA or the IGO model could also impact profits if reliability worsens significantly, or if the costs to operate either program are significantly too high.

7.2.2.3 Incentives Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	L	L	L
Outcomes-based PBR	MH	MH	M
Conventional PBR + Light HERA	LM	LM	M
Hybrid Model	MH	MH	M

*Lighter PUC Regulation is not considered in this risk category because the analysis relates to incentive mechanisms contained within PBR approaches.

Relevant Phase: Transition & Ongoing
Type: Financial

PBR models are generally structured to provide incentives to utilities to improve their performance and/or achieve specific outcomes. These incentives are closely related to risks undertaken by the utilities. PBR models that provide stronger incentives are likely to create greater financial uncertainty in outcomes, but also provide the possibility for reward.[305] Incentives Risk primarily involves the potential risk that the rewards and/or the penalties in a

[305] William Zarakas et al., Performance Based Regulation Plans: Goals, Incentives and Alignment, The Brattle Group, prepared for DTE energy, available at: https://www.michigan.gov/documents/mpsc/Brattle_Report_to_DTE_on_Performance_Based_Regulation_120617_613150_7.pdf at vi (hereinafter, "Brattle Report")

given regulatory model are set too high or too low to be effective, and also includes the risk of exposure to penalties if outcomes are not met under a given regulatory model. In terms of whether the incentives are set appropriately, the Project Team notes that the stronger the incentive, the more the utilities would want to take on additional risk (for example, to invest in new technology to increase efficiency and/or cut costs), but there is a point at which the incentive-risk ratio would begin to have a diminishing return. If incentives are set too high, utilities may overcorrect or take too great a risk to meet them. If they are too low, the utilities may not take adequate action to meet them because it will not be worth their effort.

This potential risk is considered to be Low under the Status Quo model because of the relatively small role that current PIMs play in the regulatory structure compared to alternative regulatory forms (in this analysis, the Project Team is primarily considering explicit incentives and penalties that would be implemented in a PBR framework, and not implicit incentives that the utility may receive under other models). In the alternative models, there is a risk of misaligned or dysfunctional incentives when the rewards for utilities are set too high relative to the costs of meeting targets or are not set to be reflective of the actual cost to remedy any shortfall(s), as well as risks related to the incentives inherent in rate periods of varying durations. In these models, there is also a risk that penalties for missing performance targets are not high enough to deter performance and are not set to be reflective of the actual cost to remedy any shortfall(s).

Although there is some risk in each of the models because it seems plausible that any incentives would need a period of monitoring and adjustment when first implemented, and it is also difficult to determine the extent to which any misaligned incentives can be expected, the Project Team estimates that the likelihood that rewards or penalties will be set too high or too low will vary among the regulatory models. The Project Team assigns a Medium-High probability to Outcomes-based PBR models (including the Hybrid model) because of the expanded suite of PIMs that are to be imposed in those models as compared to the Conventional PBR model, which is slightly more expansive but overall more similar to the set of PIMs that currently exist under the State of Hawaii's Status Quo model. The more extensive list of PIMs under Outcomes-based PBR models means there could be more penalties under these models if outcomes are not reached, which would not only affect incentives but ultimately rates and profits as well. Consequently, we assign a Low-Medium likelihood to Conventional PBR and a Low likelihood to the Status Quo model to reflect this relationship.

For the Conventional PBR model, the Project Team estimates a Low-Medium level of impact to ratepayers. One reason for this assessment is that ratepayers will only pay for incentives if the utilities are delivering results from which ratepayers benefit, but could bear a more significant burden if incentives are too easy for the utilities to achieve and set at too high a dollar amount. The other reason is that the revenue cap mechanism in Conventional PBR could potentially mitigate some impact to ratepayers (at least within a regulatory period). The Outcomes-based PBR models would face a similar problem if incentives are too easy for utilities to achieve, but the impact on ratepayers could be greater due to the fact that the larger number of PIMs could lead to a larger aggregate impact if more or all the incentives were incorrectly set. These ratings of Medium-High probability for Outcomes-based PBR models and Low-Medium probability for Conventional PBR also reflect the incentives and risks associated with the different lengths of rate periods. For example, longer terms, such as those used in Outcomes-based PBR (5-8 years) provides greater incentives to control costs, as well as greater possibilities to earn rewards/penalties. In contrast, the shorter terms associated with Conventional PBR (3-5 years) tend to provide less incentive to control costs, but also have less need to mitigate risks of longer time periods, as evidenced by their tendency to have fewer RAMs.[306] For the PBR models, the Project Team also estimates Medium-level severity on shareholders because it is unclear how the utilities' achievement or non-achievement of performance incentives would affect shareholders.

The potential Incentives Risk under the alternative regulatory models (Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid Model (Outcomes-based PBR, DSPP, and IGO)) can be mitigated by designing the incentives with as much information and care as possible, and by monitoring the mechanisms' operations carefully to make timely corrections. Such corrections should modify the incentive mechanisms so that utilities are appropriately incentivized to behave in such ways that achieve the goals of the regulatory model.

As the above analysis relates primarily to incentive mechanisms contained within different PBR approaches, the project team does not consider this risk category for KIUC, for which PBR is not considered.

7.2.2.4 Low DER Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	H	MH	L
Outcomes-based PBR	M	MH	L
Conventional PBR + Light HERA	MH	MH	L
Hybrid Model	LM	MH	L
Lighter PUC Regulation*	MH	MH	N/A

Relevant Phase: Ongoing
Type: Operational

The Risk of Low DER is defined as the potential risk that the regulatory model does not properly incentivize or effectuate increased DER penetration, which is a State energy goal. The Project Team treats this as a High risk under the Status Quo model, given the limited incentives provided to utilities to encourage DER penetration. The team envisions that this risk would be mitigated but not avoided under regulatory alternatives. For the models with PBR components, there is a risk that the PBR does not correctly incentivize or effectuate DER. This risk also exists under the DSPP model, which is designed to expand DER but could possibly not function as intended.

For Outcomes-based PBR, the Project Team estimates a Medium likelihood of the occurrence of Low DER due to failure or mis-design of the regulatory system. This assessment is based on the fact that the Outcomes-based PBR model is likely to incorporate increased DER penetration as the desired output, which opens the possibility that the output could not function as intended,

[306] Brattle Report at xii.

but also makes it less risky than other models that do not consider DER as a primary goal. The Project Team estimates that Conventional PBR with Light HERA has a Medium High-risk because Conventional PBR is less likely than Outcomes-based PBR to include DER as a goal, primarily since the structure of the Conventional PBR formula is based on inputs rather than outputs. In contrast, we expect the Hybrid model to have a Low-Medium likelihood of a low DER risk because DER can be an output in the PBR model, and the DSPP is intended to expand DER. While it is possible that these elements of the regulatory model will not function as intended, there is a lower risk here because there is a clearer intention to eliminate this risk. For each of these models, the severity of the impact to ratepayers is likely to be Medium-High due to the ability of DER penetration to directly affect rates and customer experience. For each of these models, the severity of the impact to shareholders is estimated as Low-Medium because changes in rates or DER penetration are less likely to affect profits but could have some effect depending on how utilities earn revenues.

The risk of low DER in the Conventional PBR with Light HERA model could be mitigated by creating incentives around DER and ensuring that HERA is capable of providing reliability for DER measures. The risks of low DER in the Outcomes-based PBR and Hybrid models can be mitigated by careful design of the PBR (and DSPP in the Hybrid model) to properly incent DER, as well as close monitoring of the PBR in operation with timely corrections when the model is not behaving as intended.

In addition to the primary analysis of Low DER Risk in relation to the counties served by the HECO companies, above, this section also briefly considers this risk in terms of KIUC on Kauai. On Kauai, this risk is lowest under the IGO model, which combines the functions of an ISO and a DSO and theoretically should encourage the development of DER. This risk could be heightened if the IGO does not operate as intended. A higher risk of low DER penetration is assumed in the HERA and reduced PUC oversight alternatives, as these would not provide any impetus to increased DER penetration. However, the Project Team acknowledges that the trade-offs between customer access to distributed renewables and the cost-effectiveness of larger renewable energy systems may be viewed differently in cooperative utility contexts than investor-owned contexts, which may impact how much consideration is given to this risk category on Kauai.

7.2.3 Reliability

This section discusses the reliability risks that may be associated with the various regulatory models. How each of the models could impact reliability is an essential topic for the State of Hawaii to consider because of the large and direct impact reliability of the electric system has on ratepayers. Additionally, this risk assessment should be of interest because the State's regulators have already shown their concern about and intent to improve reliability under the current regulatory model (e.g., by adding reliability-related PIMs and creating statutory authority for a HERA entity).

7.2.3.1 Reliability Risk

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	LM	H	LM

Outcomes-based PBR	M	H	LM
Conventional PBR + Light HERA	LM	H	LM
Hybrid Model	M	H	LM
Lighter PUC Regulation*	MH	H	N/A

Relevant Phase: Ongoing
Type: Operational

Reliability Risk is the potential risk that electric system reliability will worsen under a particular regulatory model. We assess the Status Quo as having a Low-Medium level of risk, noting that the utility is currently incentivized through existing PIMs to maintain adequate reliability standards and that reliability is monitored by the PUC, but that the continued evolution of the State of Hawaii's electric grid to accommodate new technologies may pose risks for this system – reflecting, for example, uncertainty about whether additional regulatory measures will be sufficient to maintain reliability in increased DER penetration scenarios that pose increased grid complexity.

With the addition of HERA, an independent body focused primarily on setting grid reliability standards, and monitoring and ensuring utilities' compliance with reliability standards under the oversight of the PUC, we assess this risk as Low-Medium because HERA is intended to improve reliability. However, this risk is not entirely neutralized because of the possibility that HERA may not function as intended or may not result in an improvement in system reliability. The Project Team considers inclusion of Outcomes-based PBR as leading to increasing reliability risk, as the incentive signals sent to utilities through new outcomes may encourage utilities to optimize their operations to favor other outcomes above reliability (although reliability would be expected to be included as a desired PBR outcome), and so the Outcomes-Based PBR model is assessed as having a Medium level of risk. Additionally, although the IGO and DSPP are also intended to improve reliability, the complexity in grid operations provided by the creation of an IGO and DSPP may lead to high levels of reliability risk. Therefore, the Hybrid model is assessed as having a Medium-High level of risk.

Under each of the models considered, the impact to ratepayers of poor reliability is High because poor reliability directly causes ratepayers to experience loss of service or poor-quality service. Shareholders do not experience reliability issues first-hand but would be impacted somewhat if utilities are not able to claim incentives (or must pay penalties) for PIMs associated with reliability. Shareholder severity is thus rated at Low-Medium for all models.

The potential reliability risks under the alternative regulatory models can be mitigated through careful design of reliability mechanisms and regulations, and by monitoring the mechanisms' or reliability enforcement bodies' operations carefully and making timely corrections as necessary.

The Project Team also briefly assesses these risks for the regulatory models proposed for Kauai. We anticipate that the Light PUC Regulation model would carry the most risk relatively for worsened reliability due to relaxed PUC oversight. While KIUC, as a member-owned cooperative, is considered to have adequate internal incentives to maintain reliability, a reduction in PUC oversight may create possibilities for risk. Meanwhile, the IGO and HERA models both aim to improve reliability, but carry some risk of worsened reliability in the event that either model doesn't function as intended. This risk is greater for the IGO model, which is more complex than the HERA model.

7.2.4 Infrastructure

This section addresses the risk that the regulatory models considered in this report would support the development of inefficient infrastructure. This is an important risk for the State of Hawaii to consider because of the implications that inefficient infrastructure could have on the State's ability to improve the entire grid and especially generation. Careful consideration of this risk could help the State to be more responsive to its changing needs and to be more cost-effective. This section aims to provide some guidance on this topic so that the State can understand which model might be best suited to prevent the growth of inefficient infrastructure.

7.2.4.1 Inefficient Infrastructure Risk.

Model	Likelihood	Ratepayer Severity	Shareholder Severity
Status Quo	H	H	L
Outcomes-based PBR	M	MH	L
Conventional PBR + Light HERA	LM	MH	L
Hybrid Model	LM	MH	L
Lighter PUC Regulation*	L	M	N/A

Relevant Phase: Ongoing
Type: Financial

The Risk of Inefficient Infrastructure incorporates the potential risk that the utilities continue to hold onto, or continue to invest in and thus overbuild, expensive generation assets (and to a lesser extent of importance, distribution and transmission assets), and the potential risk of stranded costs if utilities' existing infrastructure becomes redundant amid a regulatory change or shift in the market environment. Under the Status Quo model, the financial incentives granted to utilities create opportunity for a risk of inefficient infrastructure, as utility profits are tied to the capital expenditures. Under the alternative models, the risk of inefficient infrastructure would arise if the PBR model fails to remove the Capex-based incentive to make inefficient capital investments. Additional and more minor risks under the alternative models could also include failure to properly retire expensive generation assets, and failure to shift investment to DER generation and update the grid, as appropriate.

The Project Team anticipates that the likelihood of inefficient infrastructure risk occurring under the Status Quo model is High because the inherent design of the Capex based model is to maximize capital investment. Because the resulting potential for inefficient- or over-investment in generation assets could tie up costs, rates could increase or decrease with respect to the other models (not in absolute terms), which would have a High impact on Ratepayers. Under the Status Quo model, the impact of the risk to shareholders should be lower than the impact to ratepayers because shareholders are not directly impacted by rate increases. Regarding the alternative models, the Project Team estimates a Medium likelihood that Outcomes-based PBR would be able to achieve the results that would break the incentive to maximize capital investment, or incentivize efficient investment in infrastructure, because it is outputs based but could be complicated to implement correctly. For Conventional PBR with Light HERA, we estimate a Low-Medium likelihood of risk for inefficient infrastructure because the model encourages efficiency by setting cost budgets upfront, effectively requiring the utilities to operate within a limited budget and rewarding them if they come in under budget. We also estimate a Low-Medium likelihood of risk for the Hybrid model because the inclusion of the IGO to the Outcomes-based PBR model would help to ensure efficient generation planning. If any of the models fail to accomplish such objectives, the risk to ratepayers would be at a Medium-High level of impact due to the fact that such inefficiencies would probably increase rates, whereas the risk to shareholders would be lower for the same reasons described above (i.e., during discussion of Status Quo impacts for this risk).

The potential Inefficient Infrastructure Risk under the Status Quo model can be mitigated by transitioning to alternative regulatory models such as those considered in this report, which could reduce the incentives to engage in capital investment decisions, and possibly even provide financial incentives and other benefits to assist with the efficient retirement of old expensive generation infrastructure and the investment in more efficient infrastructure. Inefficient infrastructure risk under the alternative models can be mitigated through the careful and informed planning of the PBR model(s), and close monitoring and timely correction of the operating models if they begin producing unintended consequences.

While the above analysis primarily focuses on Inefficient Infrastructure risk for counties served by the HECO Companies, the Project Team also briefly considers this risk in terms of KIUC on Kauai. The Project Team anticipates that the risk of inefficient infrastructure on Kauai is approximately equal among the three proposed regulatory models, because they all are still considered within the cooperative model and are not expected to be very impacted by less PUC regulation or the addition of additional reliability entities.

7.3 Conclusion of Risk Analysis

Through this risk assessment exercise, the Project Team has determined that the potential risks associated with the four regulatory models are likely to differ within the eight risk categories. The regulatory models in this assessment include the Status Quo (COS), Outcomes-based PBR, Conventional PBR with Light HERA, and the Hybrid model. The risk categories include regulatory costs, regulatory complexity, rates, returns, incentives, reliability, low DER, and infrastructure inefficiency. Overall, the likelihood of the risk is the most variable risk assessment measure among the four models in each risk category, with different results among at least three out of four models for all the risks except rates and returns. The variation of likelihood assessments emphasized the differences in the design and purpose of the various four regulatory models. For example, for the regulatory complexity risks, the likelihood that the models' implementation and operation would be more complicated than anticipated varied in relation to how complex each model is (or how different they are from the Status Quo); with the likelihood for risk for the Status Quo model at Low, Outcomes-Based PBR and Conventional PBR with Light HERA at Medium (same level to account for the increased complexity of Outcomes-based PBR in comparison to Conventional PBR, but adding complexity to the Conventional PBR model due to its incorporation of HERA), and Hybrid model at High, which combines the more complicated PBR model with two additional models (IGO and DSPP).

In contrast, the severity of the impact to ratepayers and shareholders is largely consistent between the models for each risk. In terms of severity of risk impact to ratepayers, the impact varies between models for costs, complexity, and incentives risks but is overwhelmingly consistent for the other risks. For these other categories, the Project Team anticipates that ratepayers under any of the models can expect High severity for reliability risks, Medium-High severity for rates, low DER, and infrastructure inefficiency risks, and Medium severity profits risks. In terms of severity of impact on shareholders, the impact is generally consistent (with the occasional exception under the status quo) among the risks. The Project Team anticipates that shareholders across the models may experience High severity for returns risk, Medium severity for incentives risk, Low-Medium severity for regulatory costs, regulatory complexity, rates, and reliability risks, and Low risk for low DER and infrastructure inefficiency risks.

Through this risk assessment exercise, the Project Team has also determined some of the mitigation strategies that exist to reduce risk. In general, for risks likely to be experienced under the Status Quo model, the mitigation strategy is to implement another regulatory model, such as those considered in this report. For those alternative models, the general mitigation strategy is informed and careful design of the model, and a commitment to monitoring the model's performance and to make timely corrections as necessary.

Figure 11. Summary of Risks for Each Regulatory Model

RISK	Model	Likelihood	Ratepayer Severity	Shareholder Severity	Description
Regulatory Cost	Status Quo	L	LM	L	Risk that implementation and operation of regulatory model will be more expensive than anticipated.
	Outcomes-based PBR	MH	MH	LM	
	Conventional PBR + Light HERA	M	M	LM	
	Hybrid Model	H	MH	LM	
	Lighter PUC Regulation*	LM	LM	N/A	
Regulatory Complexity	Status Quo	L	M	M	Risk that implementation and operation of regulatory model will be more complicated than anticipated.
	Outcomes-based PBR	M	MH	M	
	Conventional PBR + Light HERA	M	MH	M	
	Hybrid Model	H	H	H	
	Lighter PUC Regulation*	L	L	N/A	
Rates	Status Quo	MH	MH	L	Risk that design of the regulatory model will cause rates to increase.
	Outcomes-based PBR	M	MH	LM	
	Conventional PBR + Light HERA	M	MH	LM	
	Hybrid Model	M	MH	LM	
	Lighter PUC Regulation*	LM	MH	N/A	
Profit	Status Quo	LM	MH	H	Risk that design of the regulatory model will cause profits to decrease.
	Outcomes-based PBR	M	M	H	
	Conventional PBR + Light HERA	M	M	H	
	Hybrid Model	M	M	H	
	Lighter PUC Regulation*	LM	M	N/A	
Incentives	Status Quo	L	L	L	Risk that incentives and penalties in the regulatory models will be ineffective in driving utility behavior.
	Outcomes-based PBR	MH	MH	M	
	Conventional PBR + Light HERA	LM	LM	M	
	Hybrid Model	MH	MH	M	
Low DER	Status Quo	H	MH	L	Risk that regulatory model will cause low DER penetration.
	Outcomes-based PBR	M	MH	L	
	Conventional PBR + Light HERA	MH	MH	L	
	Hybrid Model	LM	MH	L	
	Lighter PUC Regulation*	MH	MH	N/A	
Reliability	Status Quo	LM	H	LM	Risk that regulatory model implementation and operation will cause reliability to worsen.
	Outcomes-based PBR	M	H	LM	
	Conventional PBR + Light HERA	LM	H	LM	
	Hybrid Model	H	H	LM	
	Lighter PUC Regulation*	MH	H	N/A	
Infrastructure Inefficiency	Status Quo	H	H	L	Risk that regulatory model will incentivize capital development and create inefficient infrastructure.
	Outcomes-based PBR	M	MH	L	
	Conventional PBR + Light HERA	LM	MH	L	
	Hybrid Model	LM	MH	L	
	Lighter PUC Regulation*	L	M	N/A	

Appendix A: Scope of Work to Which this Deliverable Responds

2.3.1 – Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models.

CONTRACTOR shall identify the steps and costs required, along with a projected timeline, to change the regulatory model in the State, including all necessary approval requirements.

CONTRACTOR shall provide all work to identify the steps required to change from the current regulatory model to each recommended regulatory model. CONTRACTOR shall summarize findings in a user-friendly document detailing the steps and tying each step to the costs (or cost ranges) required for the step. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet. CONTRACTOR shall submit deliverable for TASK 2.3.1 to the STATE for approval.

2.3.2 – Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models.

CONTRACTOR shall conduct a detailed analysis to determine the legality of the regulatory models. This analysis shall identify any required changes to existing statutes or regulations and if any proceedings are necessary. The analysis shall also estimate costs, timing, and strategies for navigating through each proceeding.

CONTRACTOR shall provide all work to examine Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models. CONTRACTOR shall identify a series of regulatory categories and (a) examine them against Hawaiian legislation and statutes; and (b) benchmark them against regulatory statutes and documentation governing utility legal and regulatory structures in Hawaii and other jurisdictions. CONTRACTOR shall identify gaps in current legislation, include results of targeted interviews with other jurisdictions to determine level of difficulty of proposed changes, and provide the necessary analyses to support legal changes, timing and cost estimates. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet, if appropriate. CONTRACTOR shall submit deliverable for TASK 2.3.2 to the STATE for approval.

2.3.3 – Identification and assessment of impact of known or potential financial and operational risks for different shareholders (ratepayers, utility shareholders, taxpayers) under each regulatory model.

CONTRACTOR shall identify the known and potential financial and operational risks and bearer of those risks (e.g. ratepayers, utility shareholders, taxpayers) under each regulatory model.

CONTRACTOR shall provide all work to identify and analyze the risks facing each stakeholder group during the two stages required to transition to a new regulatory model: (1) during the transition; and (ii) during the operation of the new model. CONTRACTOR shall include, for each relevant stakeholder, a summary of their expected view of the new regulatory model, identified risk, estimated likelihood of the risk, estimated potential severity or impact, and consideration of the adequacy of typical risk mitigations. CONTRACTOR shall assess the overall risk profile as it relates to different stakeholders for each regulatory model option and present the analysis in a comparable way. CONTRACTOR shall include a written description of the analysis in MS Word and an MS Excel spreadsheet, if appropriate. CONTRACTOR shall submit deliverable for TASK 2.3.3 to the STATE for approval.

Appendix B: List of Works Consulted

Alberta Utilities Commission, "100 Years of Service and Counting," http://www.auc.ab.ca/Pages/centennial.aspx .

Alberta Utilities Commission, Annual Reviews for Fiscal Years 2009 – 2018, available at: http://www.auc.ab.ca/pages/annual-review.aspx

Alberta Utilities Commission, Bulletin 2010-10, Rate Regulation Principles – PBR, July 15, 2010, available at: http://www.auc.ab.ca/News/2010/Bulletin%202010-20.pdf .

Alberta Utilities Commission, Letter NERA Total Factor Productivity Working Papers, Jan 21, 2011.

Alberta Utilities Commission, Letter to Interested Parties – Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Process for Development of Guiding PBR Principles, May 14, 2010.

Alberta Utilities Commission, Letter to Interested Parties "Rate Regulation Initiative Round Table," at 3, February 26, 2010.

Alberta Utilities Commission, Letter to Interested Parties "Rate Regulation Initiative Application 1606029 ID 566: Process Steps," at 2, April 9, 2010.

Alberta Utilities Commission, Letter to Interested Parties, Rate Regulation Initiative Application No. 1606029 Proceeding ID 566, Retention of Consultant to Develop a Basic X Factor, Sept. 8, 2010.

Alberta Utilities Commission. Rate Regulation Initiative Decision 2012-237, issued September 12, 2012, available at http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf.

Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009).

Bonbright, Danielson and Kamerschen, Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, VA, 1988.

Bonbright, Danielson, Principles of Public Utility Rates, Public Utility Reports Inc, Arlington, VA, 1961.

California Assembly Bill No. 1890, September 23, 1996 (Stats. 1996, c. 854 (A.B. 1890), § 10, eff. Sept. 24, 1996) (codified in part, e.g., as West's Ann. Cal. Publ. Util. Code § 330).

California Independent System Operator Corporation v. FERC, 372 F.3d 395 (DC Cir. 2004).

California ISO, "About Us," accessed Sept. 24, 2018, http://www.caiso.com/about/Pages/default.aspx

Chris Ann Dickerson et al., Aloha E Komo Mai: Hawaii Introduces its New Energy Efficiency Program Structure (ACEEE 2010), available at: https://aceee.org/files/proceedings/2010/data/papers/2077.pdf.

Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924, 936 (Albany County Sup. Ct. 1996).

Energy Policy Act of 1992, 102nd Congress H.R. 776 ENR.

Energy Policy Act of 2005, Pub. L. 109-58 (Aug. 8, 2005), available at https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf .

ERCOT, "About" accessed Sept. 28, 2018, http://www.ercot.com/about

ERCOT, "ERCOT Quick Facts," Aug. 8, 2018, http://www.ercot.com/content/wcm/lists/144926/ERCOT_Quick_Facts_8818.pdf

ERCOT, "History," http://www.ercot.com/about/profile/history .

Eric Anderson, "50 Years Ago Albany Went Dark in the Great Northeast Blackout," Times Union, November 12, 2015, https://www.timesunion.com/tuplus-business/article/50-years-ago-mdash-Albany-went-dark-in-the-6616751.php

FERC Order 2000, 89 FERC ¶ 61,285, issued December 20, 1999.

FERC Order 888, 75 FERC ¶ 61,080, issued April 24, 1996.

FERC Regulations, multiple chapters.

FERC, "What FERC Does," https://www.ferc.gov/about/ferc-does.asp.

FERC, "California Independent System Operator Corporation (California ISO)," https://www.ferc.gov/industries/electric/indus-act/rto/metrics/caiso-rto-metrics.pdf

FERC, "ERCOT," https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp

FERC, 157 FERC ¶ 61,043, Docket No. RR16-6-000, Order Accepting 2017 Business Plans and Budgets, issued October 20, 2016, available at: https://www.ferc.gov/whats-new/comm-meet/2016/102016/E-5.pdf.

FERC, 2010 RTO/ISO Metrics Report: NYISO, available at https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf .

FERC, FERC Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No. PL04-15-000. October 2004.

FERC, New York Independent System Operator, https://www.ferc.gov/industries/electric/indus-act/rto/metrics/nyiso-rto-metrics.pdf, at 197

FERC, Regional Transmission Organizations (RTO) / Independent System Operators), accessed Sept. 25, 2018, https://www.ferc.gov/industries/electric/indus-act/rto.asp?csrt=2042728201376846909.

FERC. "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization." Docket No. PL04-16-000. October 2004.

Gavin Bade, "Zibelman exit interview: how the New York REV is paving the way for transactive energy," Feb. 1, 2017, https://www.utilitydive.com/news/zibelman-exit-interview-how-the-new-york-rev-is-paving-the-way-for-transac/435252/

Hawaii Administrative Rules, Chapter 6-61, available at http://puc.hawaii.gov/wp-content/uploads/2013/04/Chapter-6-61.pdf .

Hawaii Contract No. 65595 between DBEDT and LEI, signed on March 23, 2017.

Hawaii Division of Consumer Advocacy, "About the Division of Consumer Advocacy," 2007, http://www.hawaiienergypolicy.hawaii.edu/outreach-communication/legislative-briefings/_downloads/2007-division-consumer-advocacy-awakuni.pdf .

Hawaii Public Utilities Commission, Annual Reports for Fiscal Years 2013-2017, available at: http://puc.hawaii.gov/reports/annual-reports/

Hawaii Public Utilities Commission, Decision and Order No. 18353, Docket No. 99-0396, issued Feb. 2, 2001.

Hawaii Public Utilities Commission, Decision and Order No. 30089 (Approving a Framework for Energy Efficiency Portfolio Standards), Docket 2010-0037, issued Jan. 3, 2012.

Hawaii Public Utilities Commission, Decision and Order No. 31908, Docket No. 2013-0141, issued Feb. 7, 2014.

Hawaii Public Utilities Commission, Decision and Order No. 35411 ("Instituting a Proceeding to Investigate Performance-Based Regulation") Docket No. 2018-0088, issued April 18, 2018, available at: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18D18B60624J02464 .

Hawaii Public Utilities Commission, Decision and Order No. 35542 ("Admitting Intervenors and Participant and Establishing a Schedule of Proceedings"), Docket No. 2018-0088, issued June 20, 2018, available at: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18F21A72048B01105

Hawaii Public Utilities Commission, Decision and Order, Docket No. 2008-0273, issued Sept. 25 2009

Hawaii Public Utilities Commission, Decisions and Order No. 32502 "Exhibit A: Inclinations on the Future of Hawaii's Electric Utilities," Docket No. 2012-0036, issued April 28, 2014, available at: https://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32053.pdf .

Hawaii Public Utilities Commission, Docket No. 2010-0037, available at: https://dms.puc.hawaii.gov/dms/index.jsp.

Hawaii Public Utilities Commission, Docket No. 2011-0206, available at: https://dms.puc.hawaii.gov/dms/index.jsp

Hawaii Public Utilities Commission, Final Decision and Order, Docket 2008-0274 issued Aug. 31, 2010.

Hawaii Public Utilities Commission, Order Granting Intervention, Docket No. 2008-0273, Nov. 28, 2008, available at https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A08L02B04503F18952 .

Hawaii Public Utilities Commission, Order No. 23681, Docket No. 2007-0323, issued September 26, 2007.

Hawaii Public Utilities Commission, Order No. 30694 (RSWG Final Report), Docket No. 2011-0206, issued Oct. 18, 2012.

Hawaii Public Utilities Commission, Order No. 31289, Docket No. 2013-0141, issued May 31, 2013.

Hawaii Public Utilities Commission, Order No. 32053 (Ruling on RSWG Work Product), Docket No. 2011-0206, issued April 28, 2014

Hawaii Public Utilities Commission, Order No. 32735, Docket No. 2013-0141, issued March 31, 2015.

Hawaii Public Utilities Commission, Order No. 34514, Docket No. 2013-0141, issued April 27, 2017.

Hawaii Public Utilities Commission, Order No. 35165, Docket No. 2013-0141, issued December 29, 2017.

Hawaii Public Utilities Commission, Order Opening Docket, Docket No. 2011-0206, issued Sept. 8, 2011.

Hawaii Revised Statutes, Chapter 269, "Public Utilities Commission," available at: https://www.capitol.hawaii.gov/hrscurrent/Vol05_Ch0261-0319/HRS0269/ .

Hawaii Revised Statutes, Chapter 91, "Administrative Procedure," available at: http://files.hawaii.gov/dcca/oah/hrs/hrs_oah_91.pdf

Hawaii Session Laws, Act 005, April 24, 2018 (S.B. 2939, S.D.2), available at: https://governor.hawaii.gov/2018-acts/act-005-sb2939-sd2-4-24-2018/

Hawaii Session Laws, Act 097, June 8, 2015 (H.B. 623 CD1, Relating to Renewable Standards), available at https://www.capitol.hawaii.gov/session2015/bills/HB623_CD1_.pdf.

Hawaii Session Laws, Act 100, June 10, 2015 (S.B. 1050 CD1, Relating to Energy (CBRE Tariffs)), available at https://www.capitol.hawaii.gov/session2015/bills/GM1200_.PDF.

Hawaii Session Laws, Act 124, June 24, 016 (H.B. 1700 CD1, Relating to the State Budget) available at: https://www.capitol.hawaii.gov/session2016/bills/HB1700_CD1_.pdf .

Hawaii Session Laws, Act 166, June 27, 2012 (S.B. 2787 CD1, Relating to Electricity (HERA)), available at: https://www.capitol.hawaii.gov/session2012/bills/SB2787_CD1_.htm

Hawaii Session Laws, Act 211, June 27, 2013 (S.B. 1087 CD1), available at: https://www.capitol.hawaii.gov/session2013/bills/SB1087_CD1_.htm

Hawaii State Constitution, Article III.

Hawaii State Energy Office, *Hawaii Energy Facts and Figures* (June 2018), available at https://energy.hawaii.gov/wp-content/uploads/2018/06/HSEO_2018_EnergyFactsFigures.pdf .

Hawaiian Electric Company, Inc., "Power Facts – Power Supply," (last visited Aug. 21, 2018), https://www.hawaiianelectric.com/about-us/power-facts/power-supply

London Economics International LLC ("LEI"), Literature Review: regulatory economics and performance-based ratemaking – prepared for the Dept. of Energy of Nova Scotia, May 2, 2014.

Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).

NERC, "Key Players" (last visited Aug. 21, 2018), https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx .

NERC, Reliability Legislation, (last visited Aug. 21, 2018), available at https://www.nerc.com/AboutNERC/keyplayers/Pages/Reliability-Legislation.aspx .

New York Codes, Rules and Regulations, Chapter 9 §§ 7840.1 – 7863.1.

New York Department of Public Service, "Reforming the Energy Vision: About the Initiative," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument .

New York Department of Public Service, "REV Demonstration Projects," http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument

New York Department of Public Service, Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Approving EEPS Program Changes, issued December 26, 2013

New York Department of Public Service, Case 14-M-0101, opened April 24, 2014.

New York Energy Law §§ 6-104; 3-103.

New York Independent System Operator, Inc., NYISO Agreements, August 8, 2012, available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/Agreements/NYISO/nyiso_to_agreement.pdf

New York Independent System Operator, Introduction to the NYISO, July 21, 2011, available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/councils/consumer_advisory_council/Introduction_to_the_NYISO.pdf .

New York Public Service Law, sections 65 and 5.

NextEra Energy, "NextEra Energy and Hawaiian Electric Industries to Combine," December 3, 2015, http://www.nexteraenergy.com/news/contents/2014/120314.shtml

Niagara Mohawk Power Corporation D/B/A National Grid: Distributed System Platform Rev Demonstration Project – Q2 2018 Report, Case 14-M-0101, July 31, 2018.

NY Governor, "Governor Cuomo Announces Fundamental Shift in Utility Regulation," April 24, 2014, https://www.governor.ny.gov/news/governor-cuomo-announces-fundamental-shift-utility-regulation .

NY REV, "About REV," https://rev.ny.gov/about/ .

NYISO, "Who We Are," accessed Sept. 25, 2018, https://home.nyiso.com/who-we-are/.

NYISO, Frequently Asked Questions, accessed Sept. 25, 2018, https://home.nyiso.com/faq/.

Ofgem, Handbook for Implementing the RIIO model, October 4, 2010

Pacific Gas & Electric Co., 77 FERC ¶ 61,204 (1996).

Porr v. NYNEX Corp. (2 Dept. 1997) 230 A.D.2d 564, leave to appeal denied 91 N.Y.2d 807, 669 N.Y.S.2d 260, 692 N.E.2d 129.

Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

Scott Hempling, Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction (American Bar Ass'n, 2013).

State of Hawaii Public Utilities Commission, http://puc.hawaii.gov/

Texas Legislature Online, "history," https://capitol.texas.gov/billlookup/History.aspx?LegSess=74R&Bill=SB373

Tom Hunter, Public Utility Commissioner of Texas, "History of Electric Deregulation in Texas, Electric and Gas Reliability Workshop," April 17, 2012, available at: https://www.puc.texas.gov/agency/topic_files/101/PUC-History_Dereg_ERCOT.pdf

United States Code, Chapter 16, §§ 824(b)(1), 824(o).

United States Constitution, 10th Amendment.

United States Dept. of Energy, United States Electricity Industry Primer (July 2015), available at https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf .

Weston, Fredrick, "Principles of Rate Design," 1999, www.raponline.org).

William Zarakas et al., Performance Based Regulation Plans: Goals, Incentives and Alignment, The Brattle Group, prepared for DTE energy, available at: https://www.michigan.gov/documents/mpsc/Brattle_Report_to_DTE_on_Performance_Based_Regulation_120617_613150_7.pdf .

Woolf, Tim and Julie Michaels, "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry," The Electricity Journal, Issue 8, Volume 8. October 1995.

Assessment of the impact of the regulatory change to the staffing of relevant State agencies

prepared for Hawaii DBEDT by London Economics International LLC

December 28, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document is one of several working papers associated with that engagement. This memo, which corresponds to Task 2.3.4, evaluates the impact of the recommended regulatory change structure to the staffing needs of relevant state agencies (such as Public Utilities Commission ("PUC"), and the Division of Consumer Advocacy ("DCA")). Based on our analysis, we conclude that the implementation of the Outcomes-based Performance-Based Regulation ("PBR") model could require a change in the number of staff (which could be higher or lower). However, moving towards the Conventional PBR with Light Hawaii Electricity Administrator ("HERA") model or the Hybrid model may increase staffing needs. Moreover, the staff's expertise, as well as the organizational breakdowns (divisions), are very similar amongst the different potential regulatory models. The goals and complexity of energy policies, too, have impacts on the management and staffing needs of these agencies.

Table of contents

Table of figures

List of acronyms

AUC	Alberta Utilities Commission
CUB	Citizens Utility Board
DBEDT	Hawaii Department of Business Economic Development and Tourism
DBF	Department of Budget & Finance
DCA	Division of Consumer Advocacy
DCCA	Department of Commerce and Consumer Affairs
DERs	Distributed energy resources
DPS	Department of Public Service
DSPP	Distributed System Platform Provider
EIMA	Energy Infrastructure Modernization Act
FTE	Full-time equivalent
GEMA	Gas and Electricity Markets Authority
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
IGO	Integrated Grid Operator
IPART	Independent Pricing and Regional Tribunal
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NASUCA	National Association of State Utility Consumer Advocates
NER	National Electricity Rules
NSW	New South Wales
NY PSC	New York Public Service Commission
OCC	Office of Consumer Counsel
OEB	Ontario Energy Board
Ofgem	Office of Gas and Electricity Markets
PPAs	Power purchase agreements
PUC	Public Utilities Commission
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
RPS	Renewable Portfolio Standards
RRFE	Renewed Regulatory Framework for Electricity
ST	Suruhanjaya Tenaga
TNB	Tenaga Nasional Berhad
UCA	Office of the Utilities Consumer Advocate
UCB	Utility Consumers' Board
UK	United Kingdom

1 Executive Summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Tasks 2.3.4 in the project scope of work, provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies. Although several state agencies interact with the electric utilities, we are focusing this paper on similar agencies such as the Hawaii Public Utilities Commission ("PUC") and the Division of Consumer Advocacy ("DCA") in Hawaii. We have reviewed standard practices in other jurisdictions with the three potential regulatory models that were recommended in Task 2.2.6 and provided an assessment of the impact of the regulatory change to the staffing of relevant State agencies under each model.

As discussed in Task 2.2.6, the three recommended regulatory models for the City and County of Honolulu, County of Maui, and County of Hawaii include (i) Outcomes-based PBR, (ii) Conventional PBR with Light HERA, and (iii) the Hybrid model[1]. As discussed in previous working papers, the Hybrid model includes an Outcomes-based PBR, a Distributed System Platform Provider ("DSPP") and an Integrated Grid Operator ("IGO")).

Since these three recommended models are relatively innovative, only a few jurisdictions have some elements of these recommended models in their current regulatory framework, so the Project Team selected some jurisdictions for further review of staffing in relevant agencies. The United Kingdom (the "UK") and Ontario were chosen to represent the Outcomes-based PBR model. Illinois, Alberta, and New South Wales were selected to represent the Conventional PBR with Light HERA model.[2] Since no jurisdiction currently has the Hybrid model, we selected New York as an example since it is under the Reforming the Energy Vision ("REV") that have similar elements of Outcomes-based PBR as well as DSPP. New York also has an independent system operator. We compared the staffing numbers before and after the change of regulatory models to study the impact of the change on staffing relevant State agencies.

Our primary observations include the following:

- The jurisdiction (i.e., New York State) that is moving towards a Hybrid model has a higher staff-to-customers ratio in the PUC than jurisdictions with other regulatory models. This is because of the more complex regulatory framework under a Hybrid model that requires more technical staff to design and monitor the regime;

---

[1] As for the recommended regulatory models for the County of Kauai, the "Lighter PUC Regulation" model will obviously require fewer staff members in the Hawaii PUC. Detailed discussion on representative states that have lighter PUC regulation has been included in Section 5.3.2 Cooperative under Task 1.3.4.

[2] Since HERA does not exist in Hawaii and there is no similar entity in other jurisdictions, this section focuses on jurisdictions that implemented Conventional PBR only.

- Outcomes-based PBR-dominated and Conventional PBR-dominated jurisdictions, such as the UK, Ontario, Malaysia, Alberta, and New South Wales, have a lower staff-to-customers ratio in the PUC than the jurisdiction (i.e., New York State) with the Hybrid model;
- When implementing PBR mechanisms, the PUCs usually hire external consultants, which could result in the unchanged staffing needs.
- Jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratio in relevant regulatory agencies;
- Staff's skill sets and expertise are very similar across different regulatory models; and,
- The divisions under regulatory agencies are organized by function, like engineering, policy research, personnel, administration, etc.; these organizational breakdowns are similar across different regulatory models.

Based on the analysis of representative jurisdictions, we anticipate the following potential impacts on the staffing requirements of related agencies.

- The impact of an **Outcomes-based PBR model** on staffing needs is inconclusive, since the staffing needs increased in the UK, but stayed constant in Ontario after the implementation of this model (this outcome could be explained by the hiring of consultants);
- Implementation of the **Conventional PBR with Light HERA model** would potentially increase the staffing needs; and,
- Implementation of **the Hybrid model** could result in higher staffing needs than the status quo.

Furthermore, as mentioned in Task 1.3.4 and 1.4.3, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the regulatory model. Although the Hawaii PUC only regulates four electric utility companies,[3] Hawaii's aggressive renewable portfolio standards ("RPS") and other policy goals entail additional challenges to the regulatory and policy agencies. These other factors may require more staff members in these agencies, regardless of the regulatory model selected. Moreover, this analysis is a relative comparison for the purposes of comparing alternative utility ownership models. The study was not designed to assess whether or not the Hawaii PUC was appropriately staffed to meet the current demands. Our analysis was not intended to be used as an assessment of the appropriate staffing level given the specific considerations and issues for the Hawaii PUC and DCA, which is outside the scope of this study.

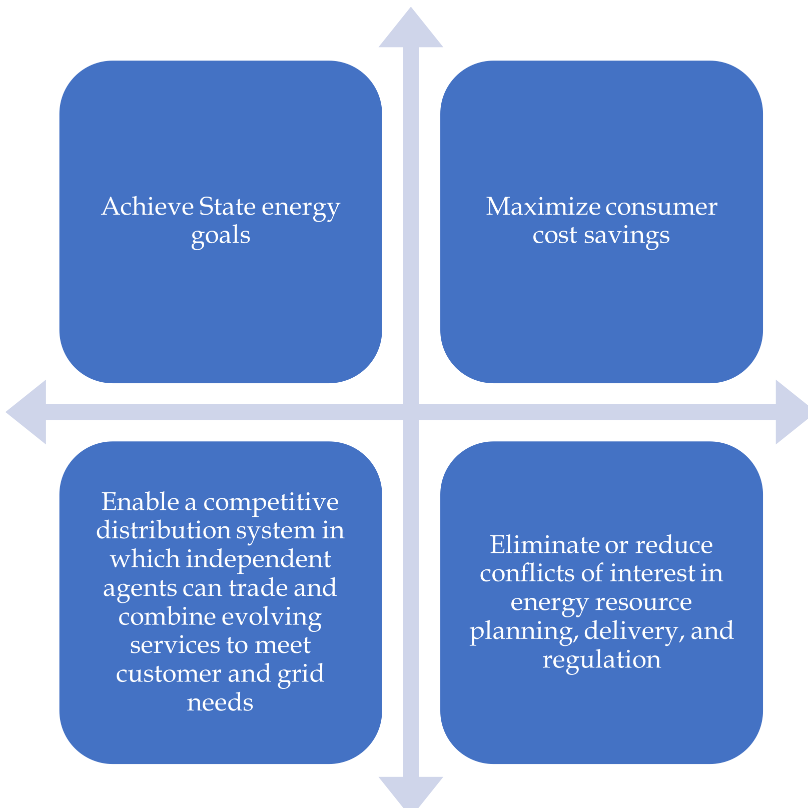
[3] As discussed in Section 3.1, in addition to the electric utilities, the Hawaii PUC also regulates gas, telecommunications, water carriers and motor carriers transportation, as well as water and waste-water services.

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[4] was contracted to perform this study.[5]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[6] listed in Figure 1.

Figure 1. State's key criteria in evaluating the models



Source: Scope of Services under Contract No. 65595

The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In

[4] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[5] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[6] House Bill No. 1700 Relating to the State Budget.

addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[7]

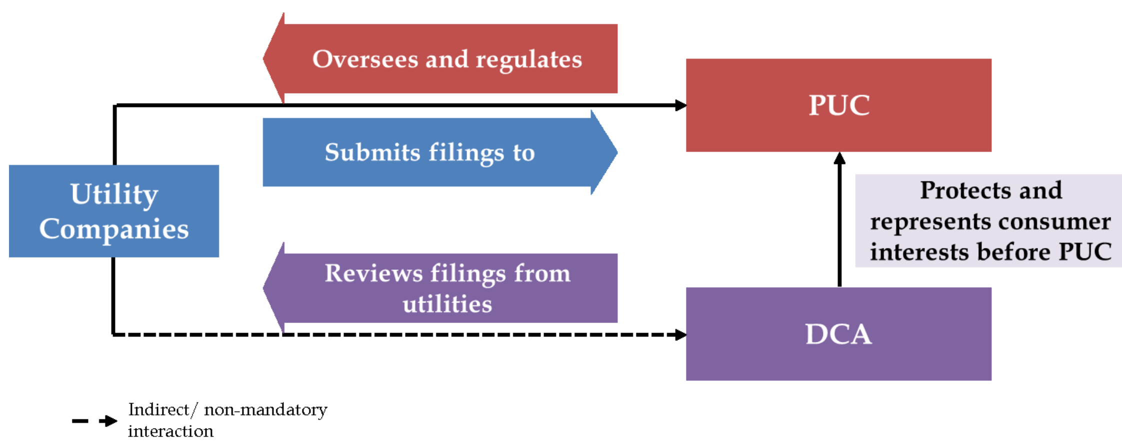
This deliverable corresponds to Task 2.3.4 in the project scope of work. It provides an estimate of the potential impacts a change in the regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders such as Hawaii PUC, and the DCA. In addition, it includes analysis of best practices in terms of staffing and expertise at public utility commissions and consumer advocate offices.

[7] Hawaii Contract No. 65595. Scope of Services.

3 Current staffing structure

A change in utility ownership might impact the various state entities that help oversee that utility or provide it with policy guidance. To assess the potential impact, we focus on State agencies and regulators that utilities usually interact with, including the Hawaii Public Utilities Commission ("PUC") and the Hawaii Division of Consumer Advocacy ("DCA"). Figure 2 summarizes the main interactions between these entities. All the utility companies in Hawaii are overseen and regulated by the PUC. Utilities are required to submit filings to the PUC regarding their proposed rates, changes, and future plans, and power purchase agreements ("PPAs") with generators, to name a few. Although utility companies are not required to report to the DCA directly, the DCA reviews filings from utilities and represents consumer interests before the PUC. These agencies are the most likely to be impacted by any ownership change of Hawaii's utility companies. We will discuss the current staffing structure of each entity below.

Figure 2. Utilities' interaction with PUC and DCA



Source: PUC, DCA, and LEI analysis.

3.1 Hawaii Public Utilities Commission

The primary duty of the PUC is to "*protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates.*"[8] Entities that are regulated by the PUC include companies that provide electricity, gas, telecommunications, water carriers, and motor carriers transportation, as well as water and waste-water services. In addition, the Hawaii PUC directly oversees Hawaii Energy, funded by a public benefits fund, and the Hawaii One Call Center, a mandatory "Call Before You Dig" program, among other programs. All the electricity utilities, namely Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Limited ("MECO"), Hawaii Electric Light Company, Inc ("HELCO"), and Kauai Island Utility Cooperative ("KIUC"), are under the authority of the PUC.

[8] HPUC. *Introduction*. Website< http://puc.hawaii.gov/about/introduction/>. Access date: October 30, 2017.

As requested by the Act 108, Session Laws of Hawaii 2014, the PUC was transferred from Department of Budget & Finance ("DBF") to the Department of Commerce and Consumer Affairs ("DCCA").[9] Given its increased administrative decision-making authority, the PUC also received additional funding that led to more staffing positions.[10] As of December 2016, the PUC has a total of 65 full-time, permanent, and funded positions; 85% of those positions were filled in FY 2016.[11] Positions include administrative, director, attorneys, engineers, auditors, researchers, investigators, neighbor island representatives, documentation staff, and clerical staff.[12] The PUC recruited and filled 23 vacant positions in FY 2017.[13] The funded positions in each division and the relevant background/expertise of staff are summarized in Figure 3.

Figure 3. Number of staff and their major background/ expertise in each division in Hawaii PUC

Divisions	Approximate # of Staff	Major background/ expertise of Staff
Office of the Commissioners	7	management, development, administration
Commission Counsel	11	legal advisory
Audit Section	4	auditing, research, analysis
Engineering Section	4	engineering, analysis
Consumer Affairs and Compliance	9	public relations, complaint resolution
Administrative Support Services	10	documentation, clerical services, information technology, coordination
Fiscal Section	3	fiscal and procurement
Personnel Section	2	recruitment, human resources
Policy and Research	15	analysis, economics, research

Source: Hawaii PUC. Response to LEI's data requests via email on November 21, 2017.

3.2 Division of Consumer Advocacy

The Division of Consumer Advocacy ("DCA") is under the DCCA. The DCA is a state agency established to "*protect and represent consumer interests before the Hawaii PUC, the Federal Communications Commission, and other local and federal agencies*."[14] It should be noted that the DCA "*assists and represents customers of utility services as a whole rather than a single customer or select group*

[9] "Commission History." *HPUC*. Website. < http://puc.hawaii.gov/about/history/>. Access date: October 30, 2017.

[10] HPUC. *Annual Report for Fiscal Year 2016* (July 1, 2015 to June 30, 2016). December 2016, page 5.

[11] Ibid, page 5.

[12] HPUC. *Annual Report for Fiscal Year 2012-13*. January 2014, page 2.

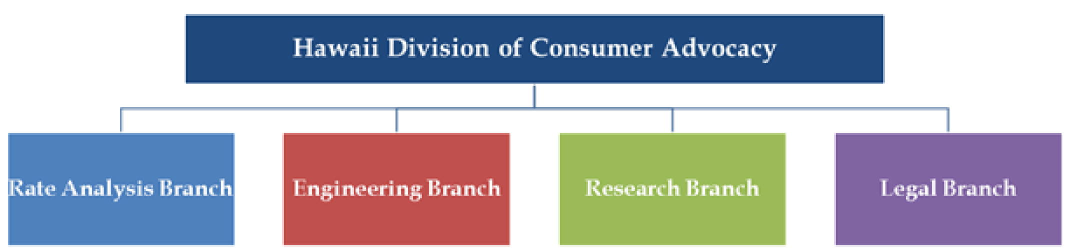
[13] HPUC. *Annual Report for Fiscal Year 2017* (July 1, 2016 to June 30, 2017). December 2017, page 5.

[14] "Divisions." *DCCA*. Website. < http://cca.hawaii.gov/divisions/>. Access date: October 31, 2017.

of people."[15] More specifically, the DCA reviews filings from public utility and transportation companies, including rate and tariff changes, capital improvement projects, integrated resource plans, certificates for authority to operate, etc.[16] In representing consumer interests before the PUC, the DCA files written statements of position or provides testimonies based on its analysis of "*financial and statistical data, prior docketed material, industry standards, and the information provided by utility and transportation companies to support their applications.*"[17]

As of 2016, DCA had 19 employees, including an Executive Director, a secretary, a utilities/transportation officer, a utilities/transportation specialist, an education specialist, rate analysts, researchers, engineers, attorneys, and clerical support.[18] Most of the professional staff are under four branches, including the Rate Analysis Branch, the Engineering Branch, the Research Branch, and the Legal Branch as shown in Figure 4 below. The Rate Analysis Branch reviews the capital structure of utilities and develops recommendations relating to rates. The Engineering Branch analyzes and makes recommendations on technical matters. The Research Branch analyzes and provides advice relating to the operations of and changes to utilities. The Legal Branch provides legal representation before regulatory agencies.[19]

Figure 4. Organizational chart of Hawaii DCA



Source: DCA. 2016 Compliance Resolution Fund Report.

---

15 Ibid.

16 DCA. *2016 Compliance Resolution Fund Report*. Page 22.

17 Ibid.

18 Ibid.

19 Ibid, Page 22-23.

4 Best practices in staffing in other jurisdictions

4.1 Public Utilities Commission

In the US, PUCs or PSCs consist of three to seven appointed or elected commissioners and professional staff who may carry the following functions.[20]

- *managing their personnel, facilities, operations: administrative staff;*
- *conducting hearings: administrative law judges, hearings examiners, attorneys;*
- *analyzing rate filings through testimony (usually pre-filed): economic, accounting and engineering staff;*
- *enforcing rules and tariffs: compliance staff, attorneys;*
- *providing technical assistance to the commissioners: advisory staff;*
- *legal analysis: attorneys;*
- *legislative analysis and reporting: policy staff; and facilitating alternative dispute resolution processes, including settlement negotiations among parties.*

Staffing in the Hawaii PUC conforms to the industry standard, given that it has three Commissioners that are appointed by the Governor and subject to confirmation by the state Senate.[21] Its functions are also consistent with the ones provided above.

The organizational chart of California PUC was used as an example to illustrate the functional lines of a typical commission in the *Electricity Regulation in the US: A Guide* published by The Regulatory Assistance Project (or "the Guide"), as shown in Figure 5. Although not every PUC or PSC is the same, this organizational chart provides an overview of the range of functions that a commission performs.[22] According to the Guide, in some states, "*the commission staff does not prepare any evidence of its own.*"[23] And in a few states, the consumer advocate is part of the commission.[24] Also, since each commission regulates a different number of utilities which serve a different number of customers, the number of staff that a PUC needs to employ varies as well. The Hawaii PUC has some divisions that are like the ones in the California PUC. For example, the Hawaii PUC has a Consumer Affairs and Compliance division which is like the Consumer Services & Information and the Consumer Protection & Safety divisions in the California PUC. But the Hawaii PUC also has some functional divisions like Engineering Section, Fiscal Section, Policy, and Research division that the California PUC does not have. The California PUC,

---

[20] Lazar, J. *Electricity Regulation in the US: A Guide. Second Edition*. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[21] Section 26-34 of the Hawaii Revised Statutes.

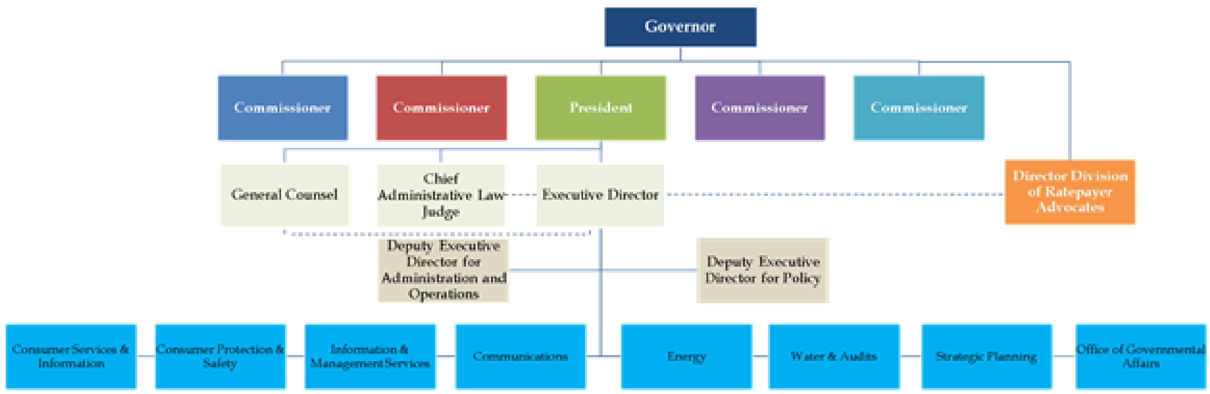
[22] Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. pages 25-26.

[23] Ibid.

[24] Ibid.

however, has divisions that are specialized in certain industries like the Energy Division and the Water & Audits division that the Hawaii PUC does not have.

Figure 5. Organizational chart of California PUC



Source: CPUC, 2016. Lazar, J. Electricity Regulation in the US: A Guide. Second Edition. Montpelier, VT: The Regulatory Assistance Project. 2016. Page 26.

4.2 Division of Consumer Advocacy

According to the National Association of State Utility Consumer Advocates ("NASUCA"), state utility consumer advocate offices were created by state legislatures in the 1970s, when natural gas and electric prices were very high during energy crises.[25] The consumer advocates were responsible for challenging the rate increases by the utility monopolies. Later, as the competition and industry deregulation evolve, state consumer advocates shift their focus to "*consumer protection issues, including service quality, reliability, and price stability*."[26] The names of these offices vary in different states, including "*People's Counsel, Public Counsel, Consumer Advocate, and Consumer Counsel*."[27] The Hawaii DCA has these tasks as part of its mandate.

Based on LEI's research, the DCA in Colorado could serve as a good example of a well-organized office, as the DCA in Colorado helped the customers save $66 for every dollar the DCA spent. The Colorado Department of Regulatory Agencies has been checking the state regulation through the various process for 40 years. They believed that "*when unnecessary or overly restrictive regulations create barriers for new practitioners and businesses to succeed, the effects can reverberate throughout the economy*."[28] The Office of Consumer Counsel ("OCC") under the Department of

---

[25] "Who We Are – The History of NASUCA." *NASUCA*. Web. <http://nasuca.org/about-us/>.

[26] Ibid.

[27] Ibid.

[28] "Celebrating 40 Years of Sunset and Regulatory Reform." *Colorado Department of Regulatory Agencies*. Website. <https://www.colorado.gov/pacific/dora-oprrr/40-years-reform>.

Regulatory Agencies serves as the consumer advocate office in Colorado. The OCC was created by the legislature in 1984 to "*represent the public interest and the specific interests of residential, small business and agricultural consumers in electric, natural gas, and telecommunications rate and rulemaking cases before the PUC, federal agencies, and the courts*."[29] The passing of *SB 271* in the legislative session eliminated telecommunications from the OCC's advocacy, which left OCC to focus on energy-related issues.[30]

The OCC has an eleven-member Utility Consumers' Board ("UCB") created statutorily. As the recent legislation required, seven of the members are appointed by the Governor, and each of the seven Congressional districts in the state shall be represented.

Moreover, "*no more than four Board members can be affiliated with the same political party*."[31] At least one member of the seven appointments will be representing expertise in agriculture, and at least two members of the seven appointments will be owners of the small business with 100 or fewer employees.[32] For the four remaining seats, "*the President of the Senate, Speaker of the House of Representatives, the Minority Leader of the Senate, and the Minority Leader of the House of Representatives shall each appoint one member.*"[33] The UCB is primarily responsible for providing general policy guidance and oversight to the OCC and its director. The Attorney General should advise the OCC and UCB on all legal matters and provide representation in proceedings.[34]

In addition, the OCC has eleven staff members in total, including seven operational staff (director, deputy director, admin, four technical analysts) and four legal staff (three attorneys and one legal assistant).[35] The background of technical analysts includes economics, engineering, policy analysis, etc.[36] Qualified external experts are also contracted with the OCC to perform research

---

[29] "About the Office of Consumer Counsel." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/about-office-consumer-counsel>.

[30] Ibid.

[31] "About the OCC – Utility Consumers' Board." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

[32] Ibid.

[33] Ibid.

[34] Ibid.

[35] Tim Villarosa, Deputy Director of the Office of Consumer Counsel. Reply to LEI's data request via email. November 27, 2017.

[36] "Advocacy – What We Do." *Colorado Department of Regulatory Agencies.* Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

and appear as an expert witness in proceedings.[37] Like the OCC, the Hawaii DCA also has staff members who focus on analysis, engineering, and legal tasks.

As for funding, the OCC is "*cash funded by the PUC Fixed Utility Fund into which public utilities pay to cover the cost of regulation*" and "*no state General Fund dollars are appropriated to the OCC.*"[38] In the Fiscal Year 2015-2016, the annual budget for OCC totals $1.7 million (including personal and legal services, operating, information technology, leased space, and indirect costs), and the OCC managed to save consumers $111 million in energy rate hikes through singular and joint efforts with the PUC staff.[39] In other words, for every dollar the OCC spent (including the management and staffing expenditures), Colorado consumers saved $66 in total.[40]

In summary, lessons learned from the OCC in Colorado can be summarized in two points. First, the statue had specific requirements on the appointed UCB members, which brings representatives from different fields with diverse expertise and political views. It is an effective way to guarantee the OCC represents interests of general consumers, especially those with less representativeness (i.e., small business). Second, the OCC is relatively transparent and cost-effective, as it can document the consumer savings for every dollar the OCC spent.

---

[37] Ibid.

[38] Colorado Department of Regulatory Agencies. *Office of Consumer Counsel FY 2015/2016 Annual Report*. Page 4.

[39] Ibid, page 3.

[40] Ibid, page 11.

5 Regulatory and policy staffing requirements under each regulatory model

5.1 Key issues

As with the broader project, in this phase, we seek to understand whether a change in a regulatory model affects the regulatory and policy staffing requirements of agencies such as the PUC and DCA and, if so, what the impacts are. In Section 3, we summarized the current staffing of these agencies in Hawaii. In this section, we reviewed and evaluated the regulatory and policy staffing requirements under each regulatory model in other jurisdictions. We assessed the staffing requirements of these agencies in representative jurisdictions under each regulatory model.

5.2 Methodology and comparators

Slightly different from the approach that was applied in Task 1.3.4 under ownership models, in this memo, the Project Team focused on the change of staffing levels before and after a change in regulatory models.

As summarized in Figure 6, for the Outcomes-based PBR, the UK and Ontario were selected as examples since both have set up Outcomes-based PBR. Illinois, Alberta, and New South Wales of Australia were chosen for the Conventional PBR with Light HERA model.[41] Since there is no Hybrid model that currently exists in other jurisdictions, we looked at New York which is in the process of transforming to a similar hybrid model including both a distribution-focused platform as well as an Outcomes-based PBR. New York also has an ISO.

Figure 6. Staff-to-customers ratio in representative states with different regulatory models

Number of staff in relevant state agencies

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	65	834	178	506	301	57	151	170	525

Number of retail electric customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
Total	*506,216*	*28,000,000*	*5,111,254*	*886,304*	*8,204,328*	*1,750,000*	*3,437,167*	*773,356*	*2,781,568*

Number of staff : 100,000 customers

	Status quo	Outcomes-based PBR			Conventional PBR with HERA Light				The Hybrid Model
	HI	UK	Ontario	Average	Malaysia	Alberta	NSW	Average	New York
PUC	12.8	3.0	3.5	3.2	3.7	2.4	4.4	3.5	18.9

Notes: (i) staff numbers under DCA are excluded from this chart since comparable DCA does not exist in the UK, Ontario, and Malaysia and the staff numbers are not publicly available in Alberta, NSW, and New York. (ii) sources of these numbers are provided in corresponding sections below. (iii) 2016 numbers were used for all jurisdictions to be consistent with the available data in Hawaii.

41 HERA currently does not exist in either Hawaii or other jurisdictions, so the Project Team focused on the analysis of conventional PBR only for this model.

contact:
Tianying Lan/ Shrutika Sainani
617-933-7229
tianying@londoneconomics.com

Also, it is important to caveat that the management structure and staffing arrangement of the PUC and DCA are affected by many factors. The sample jurisdictions were selected based on their primary regulatory models, not on their comparability to the state of Hawaii in terms of the number of customers, the number of utilities, or level of policy sophistication. However, to make the number of staff comparable, the number of customers is used to calculate the staff-to-customers ratio (number of staff: 100,000 customers) in Hawaii and each representative state. As the numbers suggested in Figure 6, even with the same regulatory model, the size of regulatory agencies may vary.

It should be noted that the policy ambition and complexity also have a critical impact on the staffing needs. For instance, as shown above, New York has the highest staff-to-customers ratio among all the sample jurisdictions. The high ratio is driven by the ambitious energy and environment policy goals and various corresponding initiatives in its Reforming the Energy Vision ("REV") initiative.

5.2.1 Outcomes-based PBR

The UK and Ontario were selected as representative jurisdictions for the Outcomes-based PBR model, primarily due to the number of years of experience with PBR, as well as the characteristics of their PBR regimes. The Project Team found that given the UK's example, the staffing needs might increase due to the setup of Outcomes-based PBR; but based on Ontario's experience, the staffing needs might not change much.

The UK has extensive PBR experience spanning over two decades. In particular, the UK's "Revenue = Incentives + Innovation + Outputs" ("RIIO"), an example of outcomes-based PBR, was quoted in the Hawaii PUC's order on PBR as "*one of the best-known examples of PBR in practice*." [42] Further details such as the overview of the market, the regulatory framework, and the history of transition and recent developments in the UK can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

Similarly, Ontario was selected as a representative jurisdiction as it also employs an Outcomes-based PBR approach. As part of its PBR regime, the Ontario Energy Board ("OEB") established the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As per the OEB, "*[the RRFE] articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities*."[43] As such, key principles include:

- "*the expectation for continuous improvement;*
- *robust integrated planning and asset management that paces and prioritizes investments,*

[42] Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

[43] "Handbook for Utility Rate Applications." *OEB*. October 13, 2016. <https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf>

- *strong incentives to enhance utility performance;*
- *ongoing monitoring of performance against targets; and*
- *customer engagement to ensure utility plans are informed by customer expectations."*[44]

The OEB believes that emphasis on the results rather than the activities will better lead to alignment with customer preferences, enhanced distribution productivity, as well as the spurring of innovation.[45] With regards to outcomes, utilities are responsible for identifying outcomes that would be valuable to customers, and accordingly, explain how said outcomes would be achieved under its plans and proposed costs. The outcomes are then associated with performance metrics, determining whether the outcomes have been achieved or not.[46] The OEB has identified four categories of outcomes to be achieved through the framework, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance.[47] The OEB has also established a set of performance metrics for electricity distributors in its Performance Scorecard; all other utilities (i.e., natural gas transmission and distribution, electricity transmission, and Ontario Power Generation ("OPG")) propose their own scorecard, similar to the one developed for distributors.[48]

5.2.1.1 PUC

United Kingdom

Generally, Ofgem's offices are organized by function; as such, the divisions cover not only electric utilities, but also natural gas utilities. The Hawaii PUC on the other hand also covers telecommunications utilities, as well as the transportation and water/wastewater industries.

As of March 2018, the UK's Office of Gas and Electricity Markets ("Ofgem") had 724 permanently employed staff (average number of full-time equivalent ("FTE") people employed).[49] This is significantly more employees than that of both the OEB and the Hawaii PUC.

---

[44] Ibid, page 2.

[45] Ibid, page 2.

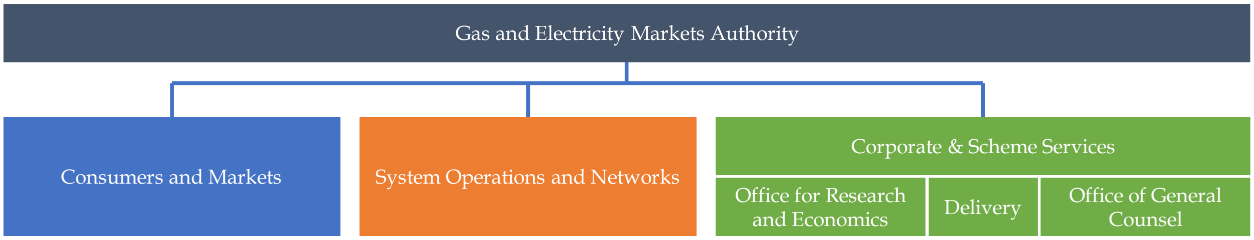
[46] OEB. *Handbook to Utility Rate Applications*. October 13, 2016. p. 15.

[47] Ibid, p. 15.

[48] Ibid, p. 16-17.

[49] Staffing levels post-organizational restructuring are lower than that of 2016 (i.e., 834 FTEs).

Figure 7. Ofgem organizational chart (post-structural reorganization)



Divisions	Function
Consumers and Markets	Looks after the interests of consumers in the energy market (wholesale and retail markets, enforcement)
System Operation and Networks	Focused on price controls (resources will particularly focus on the next round due to start in 2021) and ensuring maximum consumer benefits
Corporate & Scheme Services	Provides business support services and runs environmental schemes for Government

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

Note: The above divisions are for both the gas and electricity markets, and thus is representative of Ofgem as a whole.

Source: Ofgem, 2018.

Ofgem underwent organizational restructuring in April 2018, reducing the number of divisions from seven to three to "*better focus on protecting consumers*."[50,51] The three divisions are comprised of Consumers and Markets, System Operation and Networks, and Corporate & Scheme Services. In turn, Ofgem and its divisions are governed by the Gas and Electricity Markets Authority ("GEMA"). The new organizational structure and its functions are depicted in Figure 7, while the number of staff and details regarding the background and expertise of the staff pre-reorganization are listed in Figure 8.[52]

---

[50] "Ofgem reorganization." *Ofgem.* January 15, 2018. Web. August 21, 2018. <https://www.ofgem.gov.uk/publications-and-updates/ofgem-reorganisation>

[51] Prior to organizational restructuring, Ofgem's divisions were comprised of the following: Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve. (Source: "New Ofgem organizational structure." *Ofgem.* January 12, 2016. Web. August 21, 2018. < https://www.ofgem.gov.uk/publications-and-updates/new-ofgem-organisational-structure>

[52] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

Figure 8. Number of staff members in each division of Ofgem and their major background/expertise (pre-structural reorganization)

Divisions	Approximate # of Staff	Major background/expertise of Staff
Regulatory	366	policy advisory, planning, administration
E-Serve	241	management, administration, development & implementation, operations
Corporate Services	117	management, budgets, risk management, finance, accounting, procurement

Note: Although prior to restructuring, Ofgem's divisions consisted of Corporate Affairs, Consumers and Competition, Energy Systems, Networks, Improving Regulation, Corporate Functions, and E-Serve, Ofgem's annual reports document divisional staffing numbers under the umbrella terms shown in Figure 8.

Source: Ofgem, 2018.

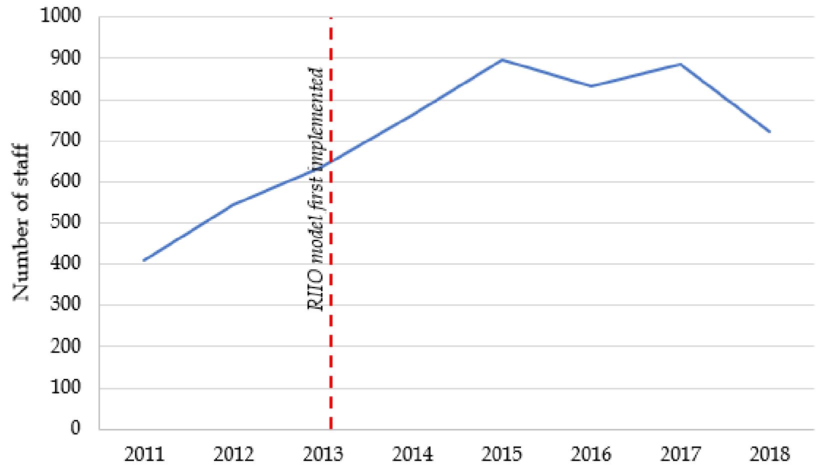
Ofgem's divisional structuring is more streamlined (i.e., has fewer divisions) than that of the Hawaii PUC. Nevertheless, both Ofgem and the Hawaii PUC have divisions dedicated to consumers (i.e., Consumer Affairs and Compliance in the Hawaii PUC and Consumers and Markets in the restructured Ofgem), a division dedicated to economics and research (i.e., Policy and Research in the Hawaii PUC and Office for Research and Economics sub-division under Corporate & Scheme Services in the restructured Ofgem) as well as an Office for Counsel (i.e., Commission Counsel in the Hawaii PUC and Office of General Counsel sub-division under Corporate & Scheme Services in the restructured Ofgem). Ofgem does not have a dedicated audit and engineering division, or an Office of the Commissioners as the Hawaii PUC does.

As can be seen, by the above numbers, Ofgem is significantly larger in terms of number of staff than the Hawaii PUC. Additionally, the Project Team notes that after the implementation of the RIIO in 2013, the number of staffing increased by 17% (from 545 in 2012 to 637 in 2013).[53] In the following year (2014), the number of staffing further increased by 19% to 761 staff, to be followed by another 18% increase in 2015 to 896 staff. The following year (2016) saw a decrease of 7% to 834 staff, only to increase again by 6% in 2017 to 886 staff.[54] Nonetheless, staffing levels decreased once again in the most recent year; in the year ending March 31, 2018, Ofgem had 724 permanently staffed FTEs, approximately 18% less than that of 2017. Overall, the adoption of the RIIO model has increased the number of staff in the UK for the first several years. Likewise, the implementation of the Outcomes-based model may result in a general increase in staffing members in the Hawaii PUC, if implemented.

[53] In addition, external experts were hired to help Ofgem with reviewing the PBR plans as well.

[54] The average number of staff decreased in 2015/2016, and the decrease was primarily "*concentrated in staff at the lower grades*." The reason for this decrease was not specified. (Source: Ofgem. *Annual Report 2015/16*.)

Figure 9. Ofgem's staffing levels before and after implementation of the RIIO model



Source: Ofgem annual reports 2010/11 – 2017/18.

Ontario

Like Ofgem, the OEB regulates both the natural gas and electricity sectors and similarly, divisions are organized by function. It does not cover telecommunications utilities or the transportation and water/wastewater industries as the Hawaii PUC does.

Similar to PUCs or PSCs in the US, the OEB acts as the energy regulator for Ontario. With the implementation of the PBR through RRFE in Ontario in 2012[55], the OEB staff's responsibilities increased and included the development of additional policies and processes pertaining to the RRFE, refine the scorecard, and develop additional incentive mechanisms.[56]

As per the *2018 to 2021 Business Plan*, the OEB has budgeted a staff headcount of 192 FTEs over the planning period, in addition to 11 FTE Board Members. Similar to Ofgem, the most recent staffing levels of the OEB are higher than that of the Hawaii PUC. The organizational structure is depicted in Figure 10, while the details regarding the background and expertise of the staff in each division are listed in Figure 11.[57]

---

[55] RRFE was first implemented in 2012, however PBR was first introduced in Ontario in 2007. Nonetheless, for the purposes of the regulatory model (i.e., Outcomes-based PBR), we will be focusing on the implementation of RRFE.

[56] OEB. *2014-2017 Business Plan*. < https://www.oeb.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2014-2017.pdf>

[57] Details regarding divisional staffing (i.e. number of FTEs), are not available post-structural reorganization. This will likely be reflected in Ofgem's 2018-19 annual report (for the year ending March 31, 2019).

Figure 10. OEB organizational chart

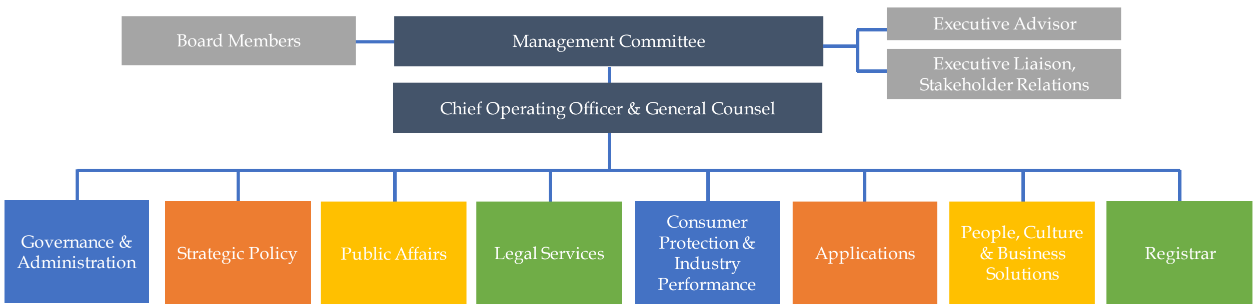


Figure 11. Divisions in OEB and major background/expertise of corresponding division's staff

Divisions	Major background/expertise of Staff
Management Committee	management, executive assistance
Chief Operating Officer & General Counsel	policy advisory, executive assistance
Governance & Administration	executive assistance, administration
Strategic Policy	strategic and policy advisory, risk management, business planning, executive assistance
Public Affairs	communications, media relations, stakeholder engagement, brand management
Legal Services	legal, strategic, and policy advisory, executive assistance
Consumer Protection & Industry Performance	management, customer assistance, auditing, licensing, compliance & enforcement
Applications	rates regulation, management, policy advisory
People, Culture & Business Solutions	human resources, finance, information technology, organizational development, procurement, facilities
Registrar	management, administration, policy advisory

Note: Staffing levels by division are not reported by the OEB.

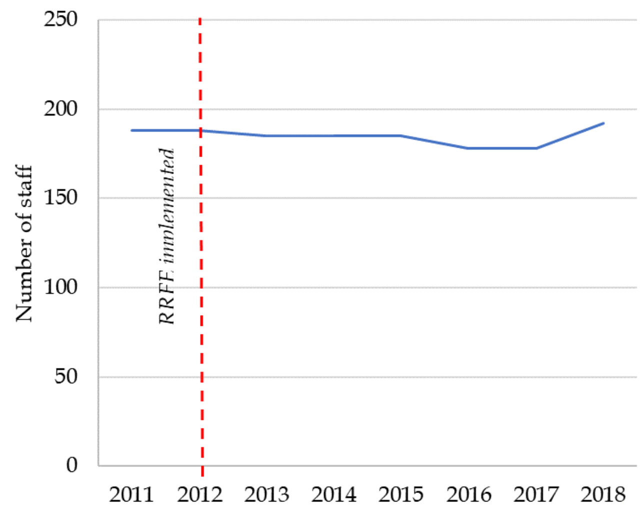
Source: OEB.

In addition to having higher overall staffing levels than the Hawaii PUC, the OEB also has more divisions. Overall, the OEB's divisional structuring is similar to that of the Hawaii PUC in the sense that both have a Commission-level committee (i.e., the Management Committee in OEB and the Office of the Commissioners in the Hawaii PUC), General Counsel divisions (i.e., Chief Operating Officer & General Counsel in OEB and the Commission Counsel in the Hawaii PUC), divisions dedicated to administration (i.e., Governance & Administration in OEB and Administrative Support Services in the Hawaii PUC), divisions dedicated to policy and research (i.e., Strategic Policy in OEB and Policy and Research in the Hawaii PUC), public relations divisions (i.e., Public Affairs in OEB and Consumer Affairs and Compliance in the Hawaii PUC), and human resource divisions (i.e., People, Culture & Business Solutions in OEB and Personnel Section in the Hawaii PUC).

Nonetheless, the OEB does not have a division dedicated to engineering and relevant analysis such as the Hawaii PUC's Engineering Section. The OEB also does not have a section performing auditing such as the Hawaii PUC's Audit Section; this activity is grouped along with customer assistance under the Consumer Protection & Industry Performance division. The Hawaii PUC, on the other hand, does not have a department dedicated to legal activities such as the OEB's Legal Services division.

While division-level staffing numbers are not available, LEI notes that total staffing level has not been significantly impacted since the implementation of the Renewed Regulatory Framework for Electricity ("RRFE") in 2012. As seen in Figure 12, year-over-year staffing levels have ranged from -4% to 8% year-over-year from 2011 (before RRFE was implemented) to 2018. One plausible explanation for this is that the OEB hires consultants to help it with its review of the utility's proposals on PBR, and therefore, it does not need to hire additional full-time staff to work on this.

Figure 12. OEB's staffing levels before and after implementation of RRFE



Note: The above staffing levels are based on "budged headcounts" of full-time staff positions over different time periods, and thus the Project Teams assumes that these are indicative of actual staffing levels. The budgeted headcount for 2014 and 2015 was not provided in OEB's *2014-2017* and *2015-2018 Business Plans*, respectively. As such, the budgeted headcount for 2014 and 2015 was assumed unchanged from OEB's *2013-2016 Business Plan Package* (i.e., a full-time headcount of 185 positions). Budgeted headcounts were not available for years prior to 2011. The staffing levels do not account for the number of Board Members.

Source: OEB *Business Plan* reports, 2011-2018.

5.2.1.2 DCA

While both the UK and Ontario have independent organizations to represent the interests of consumers, these groups are not government agencies such as the DCA in the State of Hawaii. Nonetheless, a brief discussion of these groups and their functions is provided below.

United Kingdom

The UK does not have public consumer advocacy groups such as the DCA in the State of Hawaii. Instead, in the UK, consumer advocacy for energy is undertaken by two non-governmental organizations namely Citizens Advice and the Energy Ombudsman.

Citizens Advice holds the "*statutory role as the consumer advocate for energy consumers, to represent consumers across the energy industry*."[58] It is a national charity network comprised of approximately 300 independent local charities across England and Wales.[59] The charity organization not only advises and supports consumers regarding gas and electricity complaints, but also in other areas such as employment benefits, debt and money, consumer goods, family, housing, law and courts, immigration, and health.[60]

The Energy Ombudsman is also another Ofgem-approved independent organization that helps "*handle disputes between energy companies and their customers, which includes domestic customers and micro businesses*."[61] It is a free service that is generally utilized if an energy supplier has not settled the consumer's complaint.

Ontario

Similar to the UK, Ontario does not have a public consumer advocacy group such as the DCA in the State of Hawaii. Rather, the Consumers Council of Canada is a not-for-profit, voluntary organization that represents the interests of residential customers in Ontario with regards to not only energy-related matters but also in issues pertaining to housing; justice, resolution & redress; digital economy; and product performance & safety. The Consumers Council of Canada is a member of the Canadian Consumer Initiative under the Office of Consumer Affairs, Industry Canada,[62] and advocates for the Charter of International Consumer Rights.[63] As mentioned in Task 1.3.4 (Assessment of how each ownership model impacts staffing of State agencies and stakeholders), the Consumers Council of Canada comprised of thirteen Board of Directors (including a President, a Vice President, a Secretary, a Treasurer, eight Directors, and an Executive Director), with areas of expertise including, but not limited to, of law, auditing, economics, communications, consulting, and management.[64] While its function is similar to that

---

[58] "Outcome of Ofgem price controls consultation "will be the acid test", says Citizens Advice." *Citizens Advice.* March 7, 2018. Web. August 22, 2018. < https://www.citizensadvice.org.uk/about-us/how-citizens-advice-works/media/press-releases/outcome-of-ofgem-price-controls-consultation-will-be-the-acid-test-says-citizens-advice/>

[59] Citizens Advice. *Annual report 2016/17.*

[60] "Welcome to Citizens Advice." *Citizens Advice.* Web. August 22, 2018. < https://www.citizensadvice.org.uk/>

[61] "About the energy ombudsman." *Ombudsman Services.* Web. August 22, 2018. < https://www.ombudsman-services.org/sectors/energy>

[62] Consumers Council of Canada. *About Us – Canadian Consumer Initiative*. Web. < https://www.consumerscouncil.com/index.cfm?pagePath=About_Us/Canadian_Consumer_Initiative&id=18300>.

[63] "About the Council." *Consumers Council of Canada.* Web. August 22, 2018. < https://www.consumerscouncil.com/about>

[64] Consumers Council of Canada. *Annual Report of Activities 2016 – 2017*. Page 50 – 54.

of the Hawaii DCA, the Consumers Council of Canada is not further divided into divisions/functional branches. This means that it only has one division doing all the work.

5.2.2 Conventional PBR with Light HERA

The second recommended model is a hybrid of Conventional PBR with Light HERA, as described in Task 2.2.6. Since HERA does not exist yet in Hawaii and there is no jurisdiction that has both Conventional PBR and a standalone entity (other than ISOs) that enforce reliability standards, this section focuses on jurisdictions that implemented Conventional PBR only. Moreover, as HERA is a separate entity outside of Hawaii PUC, the Project Team assumes that it would have limited impact on staffing of existing state agencies, including the PUC and DCA. The Project Team finds that the staffing numbers of relevant state agencies would increase once the Conventional PBR is implemented.[65]

Malaysia, Alberta, and New South Wales of Australia were chosen as examples because they all have Conventional PBR mechanisms in place and they are single-state or single-province jurisdictions which are more comparable to Hawaii than a country.

In Malaysia, the Conventional PBR is also called the incentive-based regulation ("IBR") which started in 2014. It applies to the Tenaga Nasional Berhad ("TNB"), the only electric utility company in Peninsular Malaysia. Revenue cap is used for transmission, system operator, and Single Buyer (operational), while pure price cap is used for customer services (i.e., distribution utilities). The Suruhanjaya Tenaga ("ST"), the energy regulator in Malaysia, used the building blocks approach to set the price. In addition, to facilitate the implementation of PBR, the ST takes the responsibilities of reviewing historical cost performance, testing efficiencies through benchmarking, recommending performance targets, etc.

In Alberta, ENMAX, a vertically integrated utility in Calgary, was the first transmission and distribution utility to propose PBR in the province before the Alberta Utilities Commission decided to introduce the approach to the other electric and natural gas distribution utilities in 2011. As an example of Conventional PBR, Alberta uses the I-X approach,[66] price cap (for electric distributors), and revenue cap (for electric transmission) together with other adjustments, such as the earnings sharing mechanism and offramps/reopeners. With the implementation of the PBR, the AUC reviews multiple regulatory submissions related to the PBR. These include the PBR plan and capital tracker filing, and many more. The PBR plans are also more comprehensive than the cost of service filings as the utilities need to submit back up their plans and proposals.

As for New South Wales ("NSW"), the National Electricity Rules ("NER") requires the implementation of an incentive-based regulatory regime in the form of a revenue cap or some incentive-based variant, which was designed to foster efficient investment and operating

[65] The staffing numbers in Illinois before and after the introduction of the Conventional PBR is not publicly available.

[66] In Alberta, "I factor" means blended input-based inflation factor based on a Canada-wide construction price index and a provincial wage index. Each index weight is 0.5 in distribution and transmission. "X factor" was approved based on a survey of historical Total Factor Productivity studies and other jurisdictions' practices.

practices and ensure the quality of service. In the NSW, transmission networks are regulated under weighted average price caps, using the building blocks approach. It also involves a symmetric earnings-sharing mechanism and off-ramps for transmission utilities. Similar to the other two examples mentioned above, the regulator in NSW had more responsibilities with the implementation of the PBR.

5.2.2.1 PUC

Malaysia

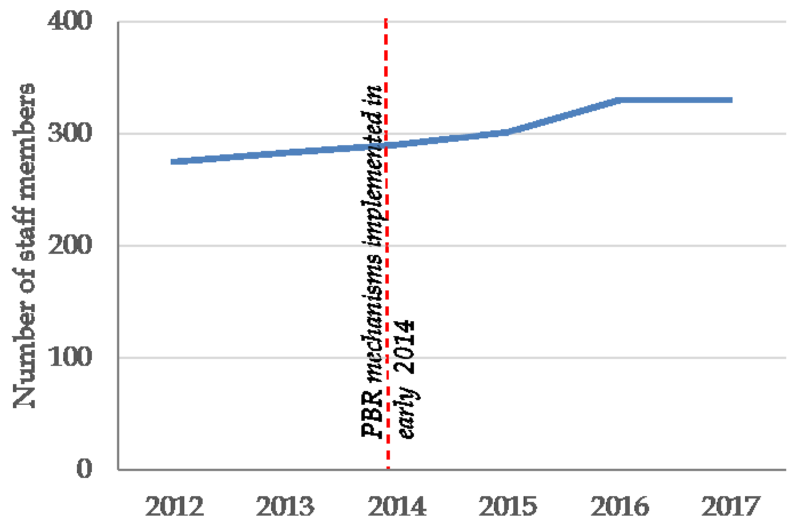
Figure 13. Organizational chart of Malaysia ST

Source: Malaysia ST. Business Plan 2015-2020. December 2015. Page 25.

As discussed in Task 1.3.4, the Energy Commission or ST in Malaysia is a statutory body established under the Energy Commission Act 2001. Its primary responsibility is to regulate the energy sector, especially the electricity supply and piped gas supply industries in Peninsular Malaysia and Sabah.[67] As shown in Figure 13, the Chairman and Chief Executive Officers lead the ST. Staff is divided into six departments, including Industry Development and Electricity Market Regulation, Energy Management and Service Quality Development, Environmental Services Administration, Electrical Safety Regulation, Gas Development and Regulation, and Corporate Services.[68] Also, there are nine regional offices under the Environmental Services Administration department.

The PBR was introduced in early 2014 in Malaysia. In that year, the total number of employees in the ST increased by 2% from 283 to 290. In the following year (2015), the staffing number increased to 301.[69] Moreover, the total number is projected to increase over the next few years and will reach 350 by 2020.[70] Admittedly, other factors, i.e., the implementation of Single Buyer in 2014, could have contributed to this increase in staffing needs as well. More workload resulted from the PBR implementation implies that more staffing members may be required in the Hawaii PUC if a Conventional PBR model is implemented.

Figure 14. ST's staffing levels before and after PBR implementation



Source: Malaysia ST. Business Plan 2015-2020. December 2015.

---

[67] Malaysia ST. *Overview of the Energy Commission*. Web. <http://www.st.gov.my/index.php/en/about-us2/overview-of-the-energy-commission>.

[68] Malaysia ST. *Business Plan 2015-2020*. December 2015. Page 25.

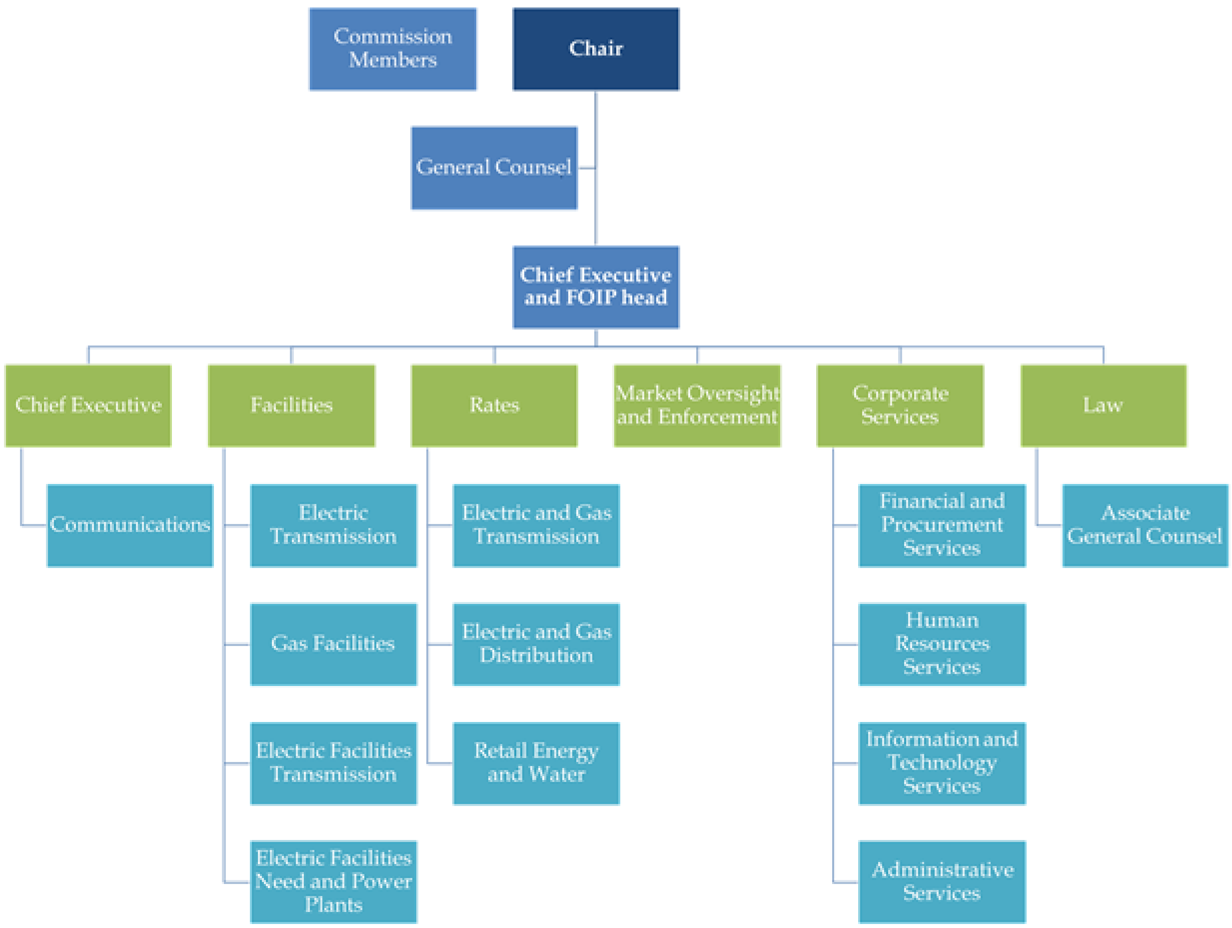
[69] Ibid, page 26.

[70] Ibid, page 26.

Alberta

The Alberta Utilities Commission ("AUC"), similar to the Hawaii PUC, regulates the investor-owned electric, gas, water utilities and certain municipally owned electric utilities in Alberta, Canada.[71] However, different from the Hawaii PUC, the AUC does not cover telecommunication utilities or transportation. As shown in Figure 15, in addition to the Chair, Commission Members, General Counsel, and Chief Executive, the AUC consists of six major divisions, namely Chief Executive, Facilities, Rates, Market Oversight and Enforcement, Corporate Services, and Law.

Figure 15. Organizational chart of the Alberta Utilities Commission



Note: FOIP – Freedom of Information and Protection of Privacy
Source: AUC. Organizational Chart. Web.
<http://www.auc.ab.ca/Shared%20Documents/AUCorganizationalchart.pdf>

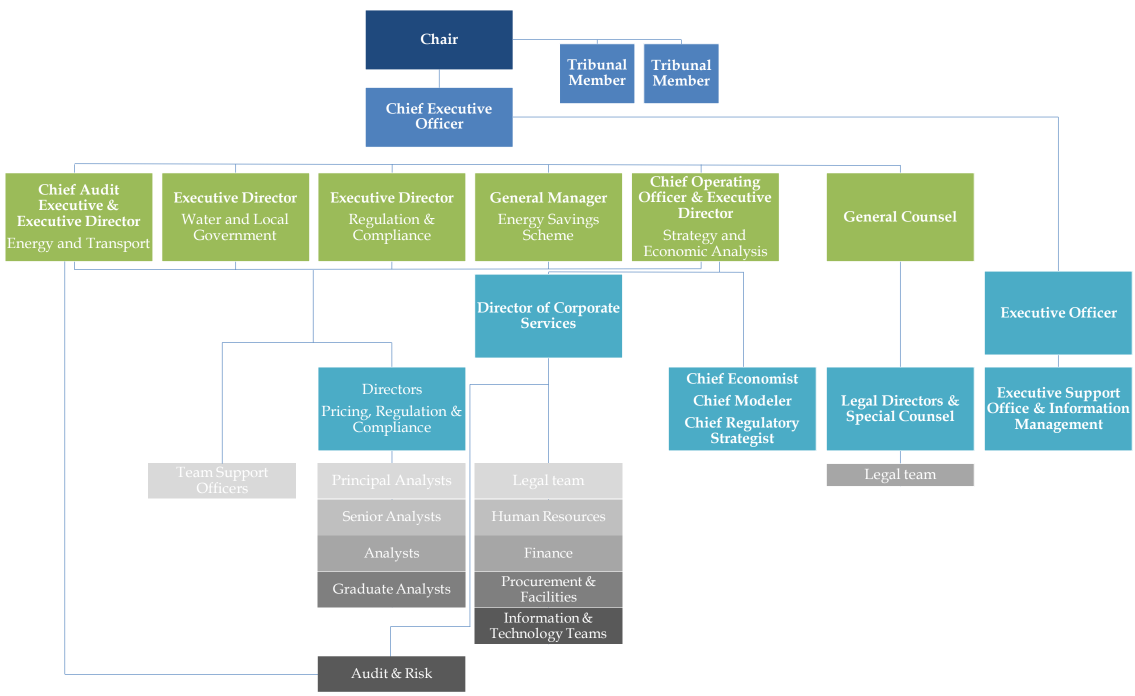
[71] "About us – who we regulate." *AUC*. Web. <http://www.auc.ab.ca/pages/who-we-regulate.aspx>. Access date: August 30, 2018.

There are around 60 employees in the AUC in the past three years (2015 – 2017),[72] but the numbers of employees in the years before the implementation of Conventional PBR are not publicly available.[73]

New South Wales

The Independent Pricing and Regional Tribunal ("IPART") is the provincial regulator responsible for the electricity, gas, water, and transport sectors, thereby serving the role of PUC in New South Wales. Unlike the Hawaii PUC, IPART does not regulate the telecommunications sector. More specifically, IPART is responsible for the economic regulation of transmission and distribution networks within New South Wales. Under the *Electricity Supply Act 1995*, IPART is also responsible for setting retail tariffs, as well as monitoring electricity licenses in distribution and supply.[74] Figure 16 depicts the divisional structure of the IPART, consisting of divisions dedicated to Energy and Transport, Licensing and Compliance, Water Pricing, and Local Government, to name a few.

Figure 16. Organizational chart of the Independent Pricing and Regional Tribunal



Source: IPART Annual Report 2016-17.

[72] Alberta PUC. *Compensation Disclosure*. 2015 – 2017.

[73] The Project Team has sent the data request to the department but has not heard back from them yet.

[74] NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions*. October 2011. p. 23.

The employment categories within the divisions, as well as the corresponding approximate number of staff and major background/expertise of said staff, are provided in Figure 17. While divisional staffing levels are not provided, Figure 16 shows that IPART has a division dedicated to compliance (i.e., Regulation & Compliance) like the Hawaii PUC (i.e., Consumer Affairs and Compliance). Both PUCs also have separate divisions for legal advisory (i.e., Commission Counsel in the Hawaii PUC and General Counsel in IPART), as well as for policy and economics research (i.e., Policy and Research in the Hawaii PUC and Strategy and Economic Analysis in IPART).

Unlike the Hawaii PUC, however, IPART does not have a separate division for audit (i.e., the Audit Section in the Hawaii PUC); instead, Audit & Risk fall under Energy and Transport, as well as under the Director of Corporate Service (which in turn is under Strategy and Economic Analysis). Also, unlike the Hawaii PUC, the IPART has divisions dedicated to sectors, such as the Energy & Transport division and the Water & Local Government division.

Figure 17. Number of staff members in the employment category of IPART in 2016 and their major background/expertise

Employment category	Approximate # of Staff	Major background/expertise of Staff
Chair	1	management
Chief Executive	1	management, operations
Executive Directors & General Managers	6	management, executive assistance, daily operations
Chief Financial Officer & Director, HR	2	human resource management, operations
Directors	16	management, daily operations
Managers	4	management, daily operations
Analysts	77	project support, technical assistance, research, analysis
Graduate Analysts	3	project support, technical assistance, research, analysis
General Counsel	1	policy advisory
Director, Legal & Special Counsel	2	legal advisory, policy advisory, planning
Legal Officers	3	legal assistance, policy advisory
Support Officers	23	technical assistance, administration, information technology
Supernumeraries	12	*N/A*
Total	***151***	***N/A***

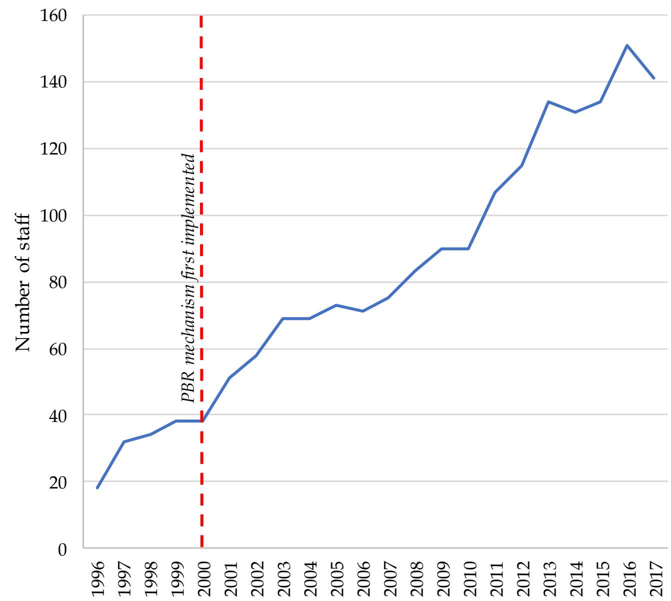
Note: The number of staff (i.e., a total of 151 employees) represent full-time, part-time, and temporary staff, as well as graduates. Tribunal members are not included.

Source: IPART Annual Report 2015-16.

As shown in Figure 17, IPART had a total of approximately 151 employees, including full-time, part-time, and temporary staff, as well as graduates in 2016 (not including Tribunal members), or 133 full-time equivalent employees.

The PBR mechanism for New South Wales was approved in 1999 and came into effect in 2000. As shown in Figure 18, the total number of staffing increased by 34% in 2001 (from 38 to 51), one year after the implementation of PBR. In 2002, the total staffing level increased further by 14% (from 51 to 58). Overall, total staffing levels have shown a generally increasing pattern since the adoption of PBR in 2000, with minor drops in 2006, 2014, and 2017, most likely due to retirements. This could mean that the implementation of the Conventional PBR with Light HERA model may increase the staffing levels required in the Hawaii PUC.

Figure 18. IPART's staffing levels before and after PBR signed into law



Note: The numbers above reflect the total headcount, not full-time equivalents. Put differently, the staffing level depicted above is comprised of full-time, part-time, and temporary staff, as well as graduates. Full-time equivalents are not provided in IPART Annual Reports prior to 2015.

Source: IPART Annual Reports (1995-2017)

5.2.2.2 DCA

Malaysia

Malaysia does not have a separate consumer advocate office. "*Balancing the needs of consumers and providers of energy*" and "*protecting public interest*" are parts of the mission of Malaysia ST.[75]

Alberta

Like the Hawaii DCA, the Office of the Utilities Consumer Advocate ("UCA") represents the interests of electricity and natural gas consumers in Alberta. The UCA is formed under the *Government Organization Act*, Schedule 13.1 and has three core functions, including education,

[75] Malaysia ST. *Vision, Mission and Core Values*. Web. <http://www.st.gov.my/index.php/en/about-us2/vision-mission-and-core-values>.

advocacy, and mediation.[76]The change in the number of staff members and their background/ expertise are not publicly available.[77]

New South Wales

The Energy & Water Ombudsman NSW ("EWON") is New South Wales' government-approved "*dispute resolution scheme*" for gas and electricity residential and small business customers, as well as some water residential and small business customers.[78,79] It was founded in 1998 as an independent service to help customers settle complaints with their respective providers. Both IPART and AER have signed a memorandum of understanding with EWON. In 2016/2017, EWON's structure was "*streamlined into four core teams working under the leadership of the Ombudsman*," namely People; Finance & Corporate Services; Investigations; and Governance, Awareness & Policy, as shown in Figure 19.[80] The number of staff members in EWON are not publicly available.[81]

Figure 19. Description of divisions and required expertise of staff members in EWON

Divisions	Description of Divisions	Major background/expertise of Staff
People	responsible for maximizing staff engagement and contribution, and develops HR strategy	human resources, development
Finance & Corporate Services	manages financial reporting, ICT infrastructure and service delivery, and general administraion and facility management	data analysis, information technology, finance, coordination
Investigations	handles customer complaints against providers, including receiving, assessing, investigating, and reviewing complaints	research, case review, assessment, resolution
Governance, Awareness & Policy	oversees governance, quality, member relations, communication, community outreach, and policy functions	policy, research, quality assurance, community engagement, communications

Source: EWON Annual Report 2016/2017

5.2.3 The Hybrid model

As discussed in the deliverables for Task 2.1.1 and 2.2.2, currently, no jurisdiction has a full-blown distribution-focused regulatory model. LEI focused on the example of New York since it is in the process of moving toward this model via REV. The REV initiative is aimed at fundamentally

[76] UCA. *Annual Report to the Minister 2016-2017.* October 16, 2017.

[77] The Project Team has sent the data request to the department but has not heard back from them yet.

[78] "About us." *Energy & Water Ombudsman NSW*. Web. September 6, 2018. < https://www.ewon.com.au/page/about-us>

[79] "Our History." *Energy & Water Ombudsman NSW.* Web. September 6, 2018. < https://www.ewon.com.au/page/about-us/our-history#founded>

[80] EWON. *Annual Report 2016/2017.*

[81] The Project Team has sent the data request to the department but has not heard back from them yet.

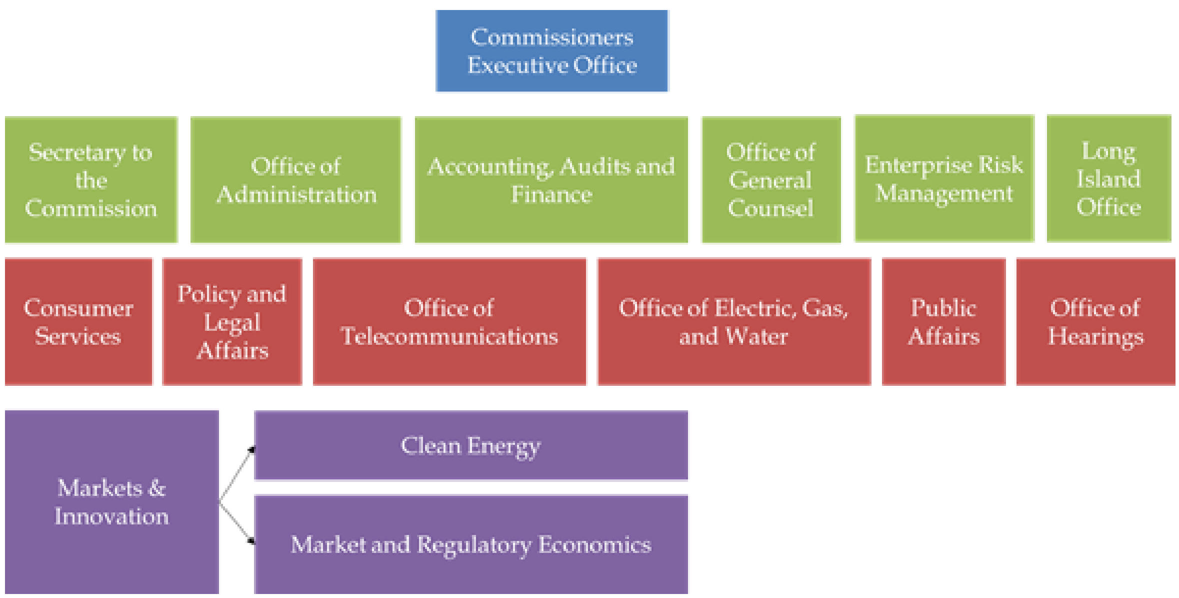
contact:
Tianying Lan/ Shrutika Sainani
617-933-7229
tianying@londoneconomics.com

shifting the role of the utility from an entity that develops and maintains transmission and distribution assets[82] to an entity that enables the localized management of electricity supply and demand. In addition, under REV, outcome-based earning opportunities will be added to the traditional ratemaking approach. Moreover, it has an ISO, which is similar to what is proposed for the independent grid operator. Admittedly, it is not the same as the Hybrid model that we proposed for Hawaii. However, this case serves as a good reference for assessing the impact of a similar hybrid model to the staffing of relevant State agencies. Further details such as the overview of the market, its regulatory framework, and the recent developments of REV in New York can be found in Task 2.2.2 (Assessment of current markets under each regulatory model).

5.2.3.1 PUC

Similar to the Hawaii PUC, New York Public Service Commission ("NY PSC") regulates the electric, gas, steam, telecommunications, and water utilities in the state. In addition, the PSC also oversees the cable industry. As the staff arm of the PSC, the Department of Public Service ("DPS") has a broad mandate to "*ensure access to safe, reliable utility service at just and reasonable rates*."[83] The DPS is organized into 14 offices, as shown in Figure 20.

Figure 20. Indictive organizational chart of New York PSC



Note: this chart is indicative only, as the official organization chart is not publicly available; color coding is added by LEI: green - departments dealing with PSC internal affairs, red - departments dealing with consumers or external entities, purple - departments highly related to regulatory changes
Source: NY DPS. Directory of Offices.

---

[82] Utilities in New York generally are not allowed to own generation assets.

[83] "About DPS." *NY DPS*. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

These 14 offices have different functions and require staff to have different background and expertise. These background and expertise are listed in Figure 21. Similar to the Hawaii PUC, the NY PSC has separate divisions that are responsible for auditing, consumer affairs, administrative services, and policy and research, etc. In addition, the NY PSC has some sectors-focused divisions that the Hawaii PUC does not have, including the Office of Telecommunications and the Office of Electric, Gas, and Water. Moreover, some functional divisions that the NY PSC has also does not exist in the Hawaii PUC, like Enterprise Risk Management, Office of Hearings, and Markets & Innovation, to name a few.

It is worth noting that the Markets & Innovation division which focuses on clean energy and market oversight did not exist prior to 2014.[84] Its formation might be relevant to the REV initiative, while in Hawaii, the Hawaii State Energy Office takes the role of leading the state's change toward clean energy independence.[85] If the Hawaii PUC set up a similar division that focuses on the transition to the hybrid regulatory model, staff members that have experience with regulatory transitioning will be needed in this division.

Under REV, the NY PSC plays a critical role in crafting the significant regulatory changes needed to make the Governor's agenda a reality.[86] The NY PSC takes the responsibility of "*aligning markets and the regulatory landscape with the overarching state policy objectives of giving all customers new opportunities for energy savings, local power generation, and enhanced reliability to provide safe, clean, and affordable electric service*."[87] Under the REV proceeding (Case number 14-M-0101), there are approximately 1,500 filed documents, 7,800 public comments, and 290 stakeholders included in the party list.[88] In addition, under this proceeding, two REV working groups were set up under Track 1, and both of them were convened by the NY DPS staff together with stakeholders.[89] Obviously, the transition under the REV model increased the workload for the NY PSC

[84] The Markets & Innovation division was not listed on the web page on NY DPS which was updated by September 2013. Source: NY DPS. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

[85] "Who we are." *Hawaii State Energy Office*. Web. < http://energy.hawaii.gov/who-we-are>. Access Date: September 11, 2018.

[86] "About the Initiative." *New York State - DPS*. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument>. Access Date: September 11, 2018.

[87] Ibid.

[88] "Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision." *NY PSC*. Web. <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number>. Access Date: September 11, 2018.

[89] "Working Groups." NY DPS. Web. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/D437F88969CCD2F985257CD20066552A?OpenDocument>. Access Date: September 11, 2018.

significantly, and transition to a Hybrid model would potentially have similar impacts on the Hawaii PUC as well.

Figure 21. Description of divisions and required expertise of staff members

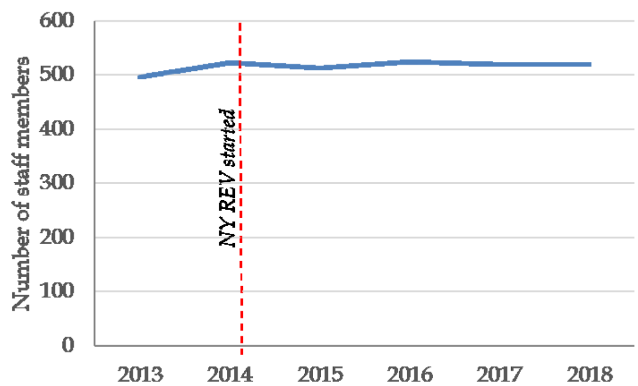
Divisions	Description of divisions	Major background/ expertise of Staff
Executive Office	senior management of the organization and relevant support	management, development, administration
Policy and Legal Affairs	special counsel and senior policy advisor regarding strategic planning; make recommendations to the Commission on policy, regulatory, and legal matters	expertise in policy, regulatory, and legal matters
Secretary to the Commission	maintaining the records of the proceedins with the DPS; coordination of the components of proceedings; etc.	administration, documentation, clercial services, knowledge of ethical responsibilities as employees, etc.
Public Affairs	an advocate for the utility regulatory policies, programs, and initiatives; an integrated internal and external communications program	communications, public relations
Long Island Office	examining the core utility operations of PSEG Long Island, and advising the Long Island Power Authority	operations of utilities
Office of Administration	consisting of three sections including the Human Resources Management section, the Administrative Management section, and the Finance and Budget section	recruitment, human resources, administrative management, fiscal, and budgeting
Consumer Services	representing consumer for all activities overseen by the Commission, taking and resolving consumer complaints and utilizing consumer input to develop consumer policy	consumer engagement, facilitation, and communications, etc.
Markets & Innovation	clean energy initiatives, market analytics and oversight	analysis, economics, research, project management, rate design, etc.
Enterprise Risk Management	identifying particular events or circumstances (risk and opportunities) relevant to the organization's objectives, assessing and addressing risks and opportunities, internal auditing	analysis, research, auditing and monitoring
Office of General Counsel	legal representation and advice; representing on behalf of the people of the state in all actions and proceedings, preparing proposed regulations and legislation, etc.	legal advisory, testimony
Office of Hearings	hearings, legal assistance, mediators in assisting parties in settlement negotiations	legal assistance
Office of Telecommunications	overseeing the performance of the telecommunication and cable television companies	knowledge about telecommunication systems, technical and safety standards
Office of Electric, Gas, and Water	focusing on utility rates and services	knowledge about utilities, system planning and operations, tariff and rates, transmission and generation siting, etc.
Accounting, Audits and Finance	performing financial audits and examinations relative to utility rate changes, mergers and acquisitions, fuel clause operations, prudence reviews, and state and federal tax changes	financial auditing, accounting

Note: staff number under each department is not publicly available

Source: NY DPS. Directory of Offices.

As shown in Figure 22, the number of staffing increased by 5% (from 496 to 523) in 2014 when Governor Cuomo initiated the REV, which might be part of the preparation for the REV. Since then, the total staffing level has not changed much in the past few years.[90] Moreover, in terms of staff level (instead of the ratio), the NY PSC already has around 500 staff members before the implementation of the REV, so the need of adding additional staff might be less significant than the Hawaii PUC which only has 65 staff members. This implies that more staffing members are required in the Hawaii PUC if the regulatory model in Hawaii will be changed to a Hybrid model that is similar to the REV in terms of complexity.

Figure 22. New York PSC's staffing levels before and after implementation of REV



Note: 2018 number was estimated by New York State in 2017

Source: NY DPS. Executive Budget (2013 - 2017)

5.2.3.2 DCA

Similar to Hawaii, there is a separate entity that advocates for consumers' interests before the PSC in New York. Under the Consumer Protection division of the Department of State in New York, there is a Utility Intervention Unit subdivision, which "*actively participates in proceedings concerning the availability, pricing, and quality of electricity and natural gas service*." Like the DCA in Hawaii, experts in this Utility Intervention Unit "*submits formal filings commenting on proposals by utilities or regulators*" and "*testify before the PSC in natural gas and electricity delivery rate proceedings involving major utilities*."[91] However, data of staffing members of this subdivision is not publicly available.[92]

---

[90] "Public Service Department - Budget Highlights." *New York State*. Web. <https://www.budget.ny.gov/pubs/archive/fy17archive/eBudget1617/agencyPresentations/appropData/PublicServiceDepartment.html>. Access date: August 24, 2018.

[91] "Utility Intervention." *Department of State*. Web. <https://www.dos.ny.gov/consumerprotection/reports/energy_utility_intervention/index.html>. Access date: August 24, 2018.

[92] The Project Team has sent the data request to the department but has not heard back from them yet.

6 Appendix A: Scope of work to which this deliverable responds

Task 2.3.4 Assessment of how each ownership model impacts staffing of State agencies and stakeholders such as the Public Utilities Commission and the Consumer Advocate similar to analysis conducted in TASK 1.3.4. CONTRACTOR shall provide an estimate of the potential impacts a change in regulatory model may have on the expertise and staffing requirements of related State agencies and stakeholders (e.g., PUC, Consumer Advocate).

DELIVERABLE FOR TASK 2.3.4. CONTRACTOR shall provide its conclusions and all work to assess how the regulatory model could impact state agencies and stakeholders such as the Public Utility Commission and the Consumer Advocate, similar to the analysis conducted on ownership models in TASK 1.3.4. CONTRACTOR shall analyze best practices in terms of staffing and expertise at public utility commissions, state energy offices, consumer advocate offices, and other relevant state agencies across a broad array of jurisdictions. CONTRACTOR shall identify at least three to five jurisdictions for each regulatory model, with staffing at their relevant state energy agencies, including the utility commissions. CONTRACTOR shall utilize high-level data, such as total staffing, from websites or in annual reports, along with the results of interviews to understand specific expertise required. CONTRACTOR shall provide a written description of the analysis in MS Word, include an overview MS Excel table listing total staffing in each jurisdiction assessed, include a breakdown for functional expertise and show an average for each of the regulatory models. CONTRACTOR shall submit deliverable for TASK 2.3.4 to the STATE for approval.

7 Appendix B: Works Cited

"About DPS." *NY DPS*. Web. <*http://www3.dps.ny.gov/W/PSCWeb.nsf/All/78F051A24B026591852576A5006D5163?OpenDocument*>. Access date: August 24, 2018.

"About the OCC – Utility Consumers' Board." *Colorado Department of Regulatory Agencies.* Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

"About the Office of Consumer Counsel." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/about-office-consumer-counsel>.

"About Us – Canadian Consumer Initiative." *Consumers Council of Canada*. Web. < https://www.consumerscouncil.com/index.cfm?pagePath=About_Us/Canadian_Consumer_Initiative&id=18300>.

"About us – who we regulate." *AUC*. Web. <http://www.auc.ab.ca/pages/who-we-regulate.aspx>. Access date: August 30, 2018.

"Advocacy – What We Do." *Colorado Department of Regulatory Agencies*. Web. <https://www.colorado.gov/pacific/dora/what-we-do-OCC>.

"Celebrating 40 Years of Sunset and Regulatory Reform." *Colorado Department of Regulatory Agencies*. Website. <https://www.colorado.gov/pacific/dora-oprrr/40-years-reform>.

"Commission History." *HPUC*. Website. < http://puc.hawaii.gov/about/history/>. Access date: October 30, 2017.

"Divisions." *DCCA*. Website. < http://cca.hawaii.gov/divisions/>. Access date: October 31, 2017.

"Handbook for Utility Rate Applications." *OEB*. October 13, 2016. <https://www.oeb.ca/oeb/_Documents/Regulatory/OEB_Rate_Handbook.pdf>

"Introduction." *HPUC.* Website< http://puc.hawaii.gov/about/introduction/>. Access date: October 30, 2017.

"Mission." *CUB*. Web. <https://citizensutilityboard.org/mission/>. Access date: August 28, 2018.

"Organizational Chart." *AUC*. Web. <http://www.auc.ab.ca/Shared%20Documents/AUCorganizationalchart.pdf>

"Public Service Department - Budget Highlights." *New York State*. Web. <https://www.budget.ny.gov/pubs/archive/fy17archive/eBudget1617/agencyPresentations/appropData/PublicServiceDepartment.html>. Access date: August 24, 2018.

"Utility Intervention." *Department of State*. Web. <https://www.dos.ny.gov/consumerprotection/reports/energy_utility_intervention/index.html>. Access date: August 24, 2018.

"Who We Are – The History of NASUCA." *NASUCA*. Web. <http://nasuca.org/about-us/>.

"About the Council." *Consumers Council of Canada.* Web. August 22, 2018. < https://www.consumerscouncil.com/about>

"About the energy ombudsman." *Ombudsman Services.* Web. August 22, 2018. < https://www.ombudsman-services.org/sectors/energy>

Malaysia ST. *Overview of the Energy Commission*. Web. <http://www.st.gov.my/index.php/en/about-us2/overview-of-the-energy-commission>.

Malaysia ST. *Business Plan 2015-2020*. December 2015. Page 25.

"New Ofgem organizational structure." *Ofgem.* January 12, 2016. Web. August 21, 2018. < https://www.ofgem.gov.uk/publications-and-updates/new-ofgem-organisational-structure>

"Ofgem reorganization." *Ofgem.* January 15, 2018. Web. August 21, 2018. <https://www.ofgem.gov.uk/publications-and-updates/ofgem-reorganisation>

"Welcome to Citizens Advice." *Citizens Advice.* Web. August 22, 2018. < https://www.citizensadvice.org.uk/>

Citizens Advice. *Annual report 2016/17.*

Colorado Department of Regulatory Agencies. *Office of Consumer Counsel FY 2015/2016 Annual Report*.

Consumers Council of Canada. *Annual Report of Activities 2016 – 2017*.

DCA. *2016 Compliance Resolution Fund Report*. Page 22.

Hawaii PUC. *Instituting a Proceeding to Investigate Performance-Based Regulation* (Order No. 35411). Docket No. 2018-0088. April 18, 2018.

Hawaii PUC. Response to LEI's data requests via email on November 21, 2017.

HPUC. *Annual Report for Fiscal Year 2012-13*. January 2014.

HPUC. *Annual Report for Fiscal Year 2016* (July 1, 2015 to June 30, 2016). December 2016.

Lazar, J. *Electricity Regulation in the US: A Guide. Second Edition*. Montpelier, VT: The Regulatory Assistance Project. 2016.

NSW Government. Department of Premier and Cabinet. *Final Report of the Special Commission of Inquiry into the Electricity Transactions.* October 2011.

Tim Villarosa, Deputy Director of the Office of Consumer Counsel. Reply to LEI's data request via email. November 27, 2017.

UCA. *Annual Report to the Minister 2016-2017.* October 16, 2017.

Revenue requirements forecasts under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

September 26, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which responds to Tasks 2.5.1 and 2.5.3, is one of several working papers associated with that engagement. It provides a background on revenue requirement calculations under different regulatory models and how it informed the assumptions, inputs, and approach used by the Project Team to project the components that constitute revenue requirements under each regulatory model for each county.

Three different variants of Performance-based Regulation ("PBR") models resulted in the lowest projected revenue requirements on each of Honolulu, Hawaii, and Maui Counties. The key factors impacting revenue requirements in these counties are the utilities' allowed rate of return and the capitalization rate applying to total utility expenditures. For Kauai County, the differences between the four regulatory models considered were under 1%; a softer touch regulatory approach had the lowest expected revenue requirements.

Table of Contents

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Gabriel Roumy/Utsav Dhoj Adhikari
617-933-7225
gabriel@londoneconomics.com

Table of Figures

List of acronyms

Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
O&M	Operations and Maintenance
Opex	Operating expenditures
PBR	Performance-based Regulation
PIM	Performance Incentive Mechanism
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PSR	Platform Service Revenue
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
Totex	Total expenditures
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which responds to Tasks 2.5.1 and 2.5.3 in the project scope of work, provides an overview of the revenue requirement calculations in the accompanying MS Excel workbooks. It describes the conceptual framework behind revenue requirement calculations and differences between regulatory models that inform the Project Team's approach and assumptions used to project revenue requirements for each county through 2045 under each regulatory models. The various regulatory models considered were described in previous working papers[1] and included:

- status quo with increased oversight from a Hawaii Electricity Reliability Administrator ("HERA") entity or the "HERA model";
- different variants of Performance-Based Regulation ("PBR");
- Integrated Grid Operator ("IGO");
- Distributed System Platform Provider ("DSPP"); and
- Lighter regulation of the Kauai Island Utility Cooperative ("KIUC") by the Hawaii Public Utilities Commission ("PUC") or the "Lighter PUC regulation."

Based on the analyses conducted, the recommended regulatory models evaluated for Honolulu, Hawaii, and Maui Counties were:

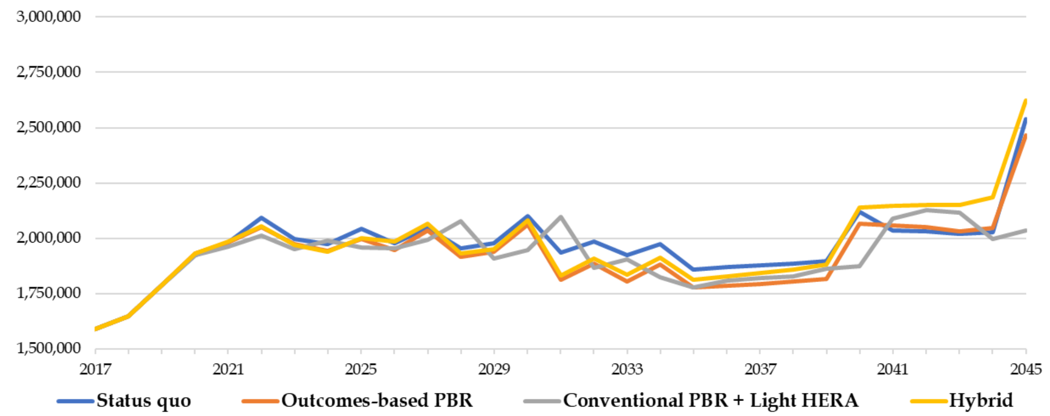
- Status quo or the current Cost-of-Service ("COS") model for an Investor-Owned Utility ("IOU") (this is the reference case),
- Outcomes-based PBR model,
- Conventional PBR + Light HERA model, and
- Hybrid model (combining Outcomes-based PBR, IGO, and DSPP).

The Project Team also assessed four separate regulatory models for Kauai County, namely, the status quo (co-op), Lighter PUC Regulation, HERA, and IGO models.

Using the approach and assumptions described below in Section 3.2, the Project Team estimated revenue requirements out to 2045 under the status quo for each county. Then, the Team calculated the revenue requirements for each county under the alternative regulatory models. The projections reflect the utilities' current capital costs and structure, planned capital spending on grid infrastructure, existing assets, resource plans, and current operating expenses, adjusted for expected changes in load, customers, and resource mix in the future.

[1] Such as Tasks 2.1.1, 2.2.1, and 2.2.6.

Figure 1. Honolulu County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.57% - $ millions			
$22,410	$22,011	$22,023	$22,257
Revenue requirements growth (CAGR): 2018 - 2045			
1.61%	1.50%	0.78%	1.73%

Note: HECO's WACC (7.57%) was used as the discount rate to calculate NPV

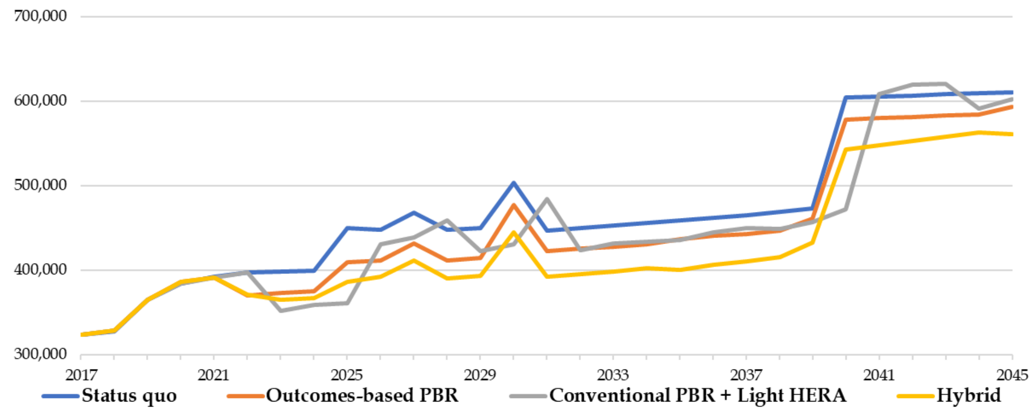
The projections for Honolulu County, as shown in Figure 1, result in increased revenue requirements under all regulatory models in the near-term, decreasing slightly until 2035, and growing again thereafter. The planned addition of 400 MW of offshore wind generation in both 2040 and 2045 contributes to the increase in projected revenue requirements for those years for all models. The planned biodiesel conversions of current diesel plants cause an even greater spike in 2045. Revenue requirements are forecast to be highest under the Hybrid model after 2040 because of additional costs associated with operating a DSPP.

Over the entire forecast horizon, revenue requirements forecast is highest in Net Present Value ("NPV")[2] terms under the status quo and lowest for the Outcomes-based PBR model, due to more consistent reductions in expenses relative to the status quo. In straight-average terms, the Conventional PBR + Light HERA model is forecast to have the lowest revenue requirements.

Similarly, Figure 2 shows that revenue requirements are projected to rise steadily in Hawaii County under all the regulatory models, with a spike in 2040 due to biodiesel conversion of utility-owned oil-fired generation units. Projected revenue requirements are highest under the status quo model than the other regulatory models for most years between 2020 and 2040. Overall, in NPV terms, the status quo has the highest forecast revenue requirements, and the Hybrid model has the lowest due to the impact of Earnings Sharing Mechanisms ("ESMs"). In each regulatory period, the projected excess earnings from the prior regulatory period are shared with the customers, thus lowering the final revenue requirements.

[2] Net Present Value represents the present value (as of 2018) of the revenue requirements over the entire forecast horizon. Revenue requirements for future years are discounted at a discount rate – the utility's cost of capital – to account for the time value of money.

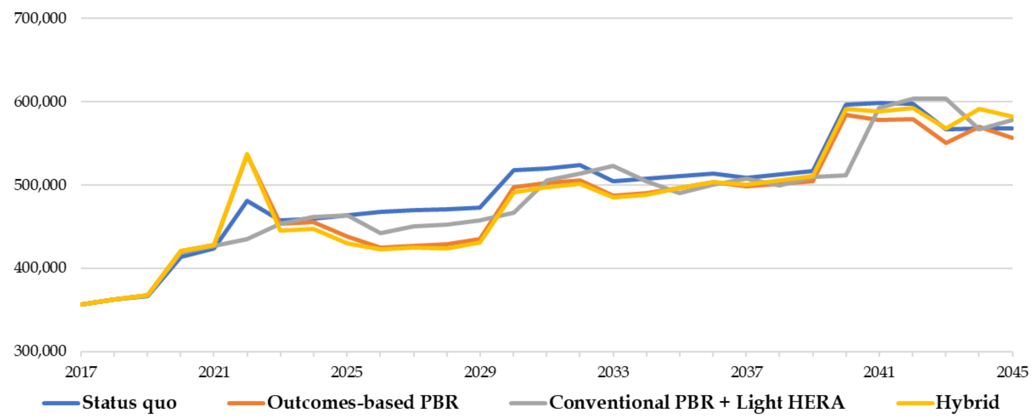
Figure 2. Hawaii County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.79% - $ millions			
$4,870	$4,650	$4,659	$4,477
Revenue requirements growth (CAGR): 2018 - 2045			
2.33%	2.22%	2.27%	2.00%

Note: HELCO's WACC (7.79%) was used as the discount rate to calculate NPV

Figure 3. Maui County revenue requirements forecast by regulatory model ($000s, nominal)

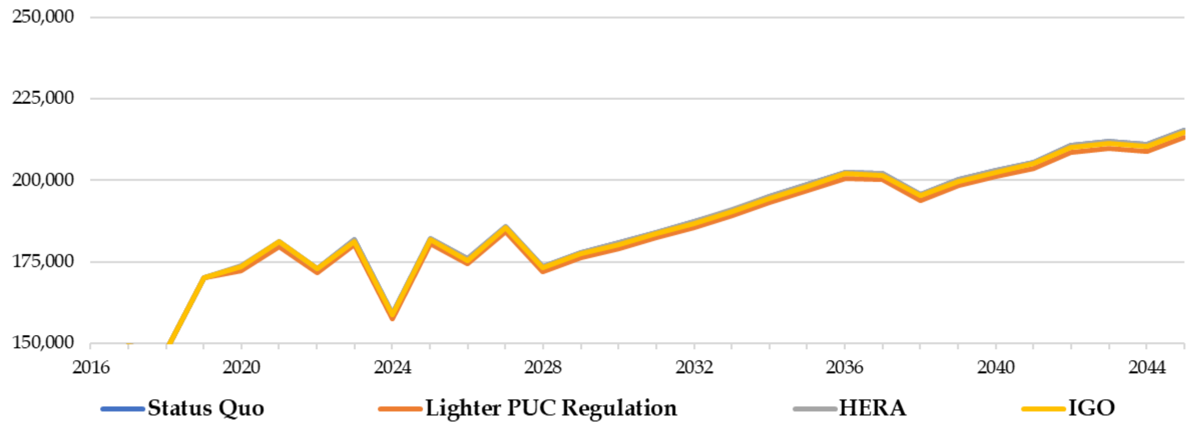


Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.43% - $ millions			
$5,438	$5,330	$5,326	$5,319
Revenue requirements growth (CAGR): 2018 - 2045			
1.68%	1.59%	1.74%	1.77%

Note: MECO's WACC (7.43%) was used as the discount rate to calculate NPV

The revenue requirements in Maui County are also expected to increase until 2040 and stabilize subsequently under all regulatory models. Over the entire forecast horizon, the Conventional PBR + Light HERA model has the lowest revenue requirements forecast, which can be attributed to the revenue cap and a more limited set of Performance Incentive Mechanisms ("PIMs") compared to the other two alternative regulatory models.

Figure 4. Kauai County revenue requirements forecasts by regulatory model ($000s, nominal)



Status quo	Lighter PUC Regulation	HERA	IGO
NPV (2018-2045) at 5% - $ millions			
$2,722	$2,701	$2,722	$2,717
Revenue requirements growth (CAGR): 2018 - 2045			
1.40%	1.36%	1.40%	1.39%

Note: KIUC's cost of debt was rounded up to 5% for the discount rate to calculate NPV

The revenue requirements in Kauai County are projected to grow under all regulatory models in the short-term, fluctuate between 2021 and 2029, and increase again afterwards under all four regulatory models. These trends are primarily driven by capital expenditures and reductions in power supply expenses (fuel and purchased power). The difference in revenue requirements forecast under all three alternative regulatory models relative to the status quo is expected to be under 1% throughout the forecast horizon. This is because the additional costs due to the change in the regulatory models are small relative to the overall expenditures (capital and operating and maintenance costs).

In summary, for Honolulu, Hawaii, and Maui Counties, revenue requirements are expected to be highest under the status quo model. The three recommended models each result in the lowest projected revenue requirements in one county:

- Outcomes-based PBR on Honolulu County;
- Hybrid model on Hawaii County; and
- Conventional PBR + Light HERA model on Maui County.

For Kauai County, Lighter PUC Regulation results in the lowest revenue requirements and the HERA model in the highest.

717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com
contact:
Gabriel Roumy/Utsav Dhoj Adhikari
617-933-7225
gabriel@londoneconomics.com

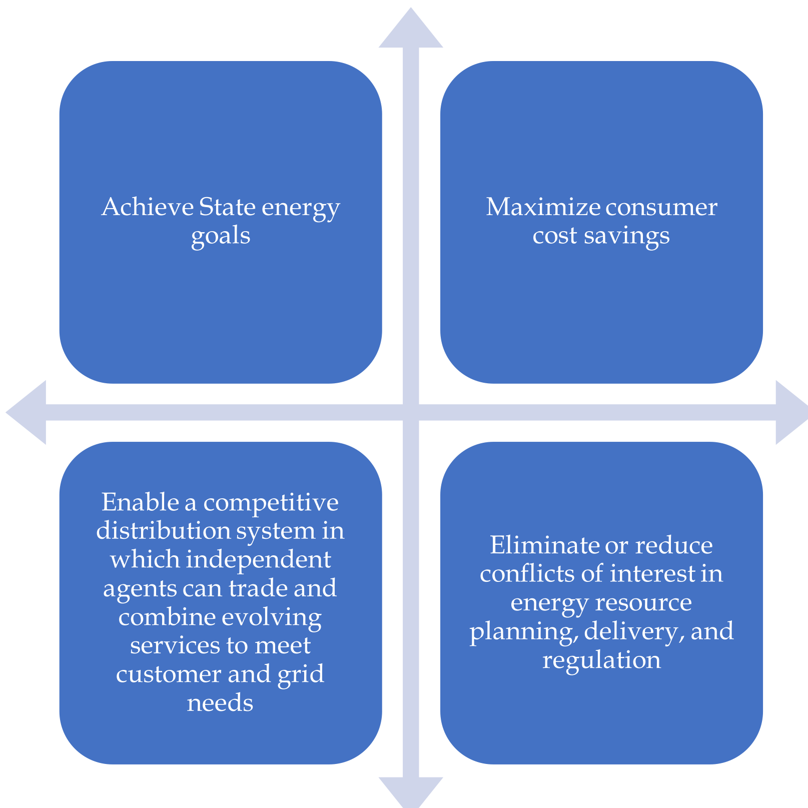
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[3] was contracted to perform this study.[4]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[5] listed in Figure 5.

Figure 5. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

---

[3] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[4] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[5] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[6]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Tasks 2.5.1 and 2.5.3 in the project scope of work. It projects revenue requirements out to 2045 for the three Investor-Owned Utilities ("IOUs") in the State of Hawaii under four regulatory models as described previously in Task 2.2.1:

- status quo (the COS model),
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model.

The Project Team also evaluated four separate regulatory models for Kauai County:

- the status quo (cost-of-service under cooperative utility or "co-op"),
- Lighter PUC Regulation,
- HERA model, and
- IGO models.

This report discusses the components and calculations of revenue requirements under different regulatory models. Based on this discussion, the Project Team developed financial models to project revenue requirements. The analysis was conducted at a county level and is included in the accompanying MS Excel workbooks.

The Project Team conducted a thorough review of utility rate case filings, regulatory filings, public reports and statements, and various industry publications and data sources to collect the data and derive assumptions necessary for the revenue requirement calculations.

2.3 Future refinements

As noted earlier, this deliverable is subject to further refinement and modification as the project moves forward and as we receive feedback from DBEDT.

[6] Hawaii Contract No. 65595. Scope of Services.

3 Revenue requirements

The different regulatory models vary in terms of accompanying mechanisms, risks, targets, rewards, and penalties. The ability of each regulatory model to achieve various policy goals and performance targets have been discussed before in previous working papers. This report provides a comparison of revenue requirements forecast under different regulatory models and helps to quantify the appropriate level of compensation for the utility for its services under four regulatory models.

3.1 How are revenue requirements set under each regulatory model?

Regulatory models include different mechanisms that can impact revenue requirement calculations. For this analysis, the Project Team analyzed three different regulatory models in addition to the status quo for each of the four counties. The approach and calculations conducted for this analysis were similar to those performed to forecast revenue requirements under ownership models in Task 1.6.1. There are no fundamental changes in assumptions except for the PBR mechanisms. There are some additional administrative expenses due to PBR, some reductions in operating expenses, and fees for the new entities like Light HERA and IGO. Essentially, revenue requirements calculations under the various regulatory models represent additional features and components "bolted on"[7] to the underlying calculations in the status quo models. The underlying IOU structure of the HECO Companies and the co-op model of KIUC affected both the choice of recommended regulatory models and the revenue requirement calculations. This section provides an overview of the revenue requirement calculations under each model; specific assumptions used in the calculations are provided in Section 3.2.

3.1.1 IOU

3.1.1.1 Status quo

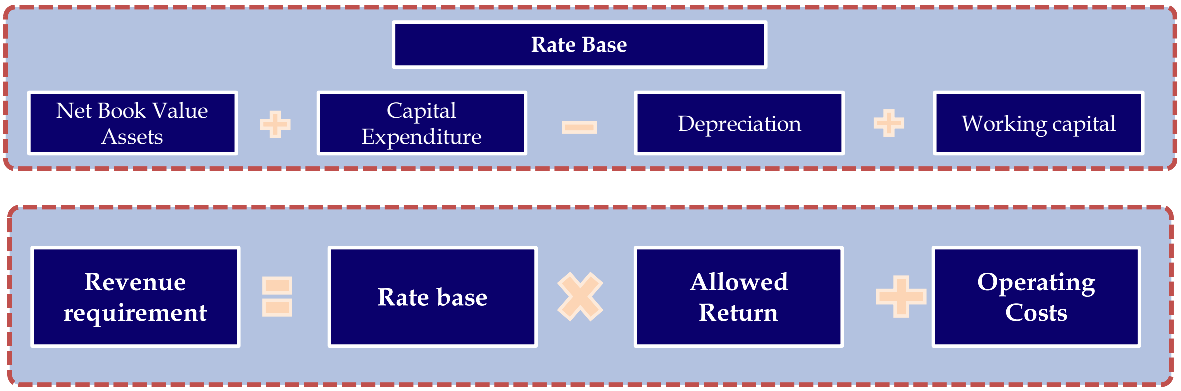
There are three key components of the revenue requirements for an IOU: (i) the Regulatory Asset Base ("RAB"), (ii) the allowed rate of return, and (iii) operating costs. The RAB consists of investments made by the utility in various physical assets and infrastructure necessary to provide electric service on which the utility is allowed to earn a fair rate of return. The allowed rate of return is based on the utility's Weighted Average Cost of Capital ("WACC"), which is itself based on the weighted average cost of debt and equity faced by the utility. The different approaches that can be used to obtain the cost of debt and equity, as well as the appropriate capital structure for the utility, are typically explored in detail during rate case proceedings by the utility, the PUC, as well as other intervenors. Finally, operating costs such as fuel, power supply, tax, and other operations and maintenance ("O&M") expenses of the utility are typically passed through to the ratepayers; IOUs do not earn a return on these expenses under the standard cost-of-service

---

[7] Bolt-on technology refers to a new software or hardware that can be seamlessly integrated with an existing underlying system. Here, the term bolt-on is used strictly from a financial modeling standpoint. Revenue requirements for the recommended regulatory models are calculated by adjusting the model for the status quo to account for the additional costs and changes in underlying expenses due to PBR, Light HERA, and IGO. In practice, the changes would be more bottom-up – changes in investments and expenditure under the new regulatory models would result from utilities adjusting individual components of resource and capex plans.

ratemaking paradigm. A more detailed description of revenue requirement determination for IOUs can be found in the Task 1.6.1/1.6.3 report and are summarized below in Figure 6.

Figure 6. Rate base and revenue requirement formulae for IOUs



3.1.1.2 Outcomes-based PBR

Under an Outcomes-based PBR model, the outcomes and performance targets to be achieved by the utilities over a regulatory period (the term of which is part of the regulatory framework) are set during rate case proceedings. The Project Team assumes a regulatory period of 5 years for Outcomes-based PBR. The regulatory framework also includes incentives (both rewards and penalties) to achieve the targeted performance levels. Utilities are incented through both PIMs and ESMs. Revenue requirements under this model will be determined using a combination of a total expenditure ("totex") approach, PIMs, and ESM. A simplified graphical summary of revenue requirement calculations under this model is shown in Figure 9.

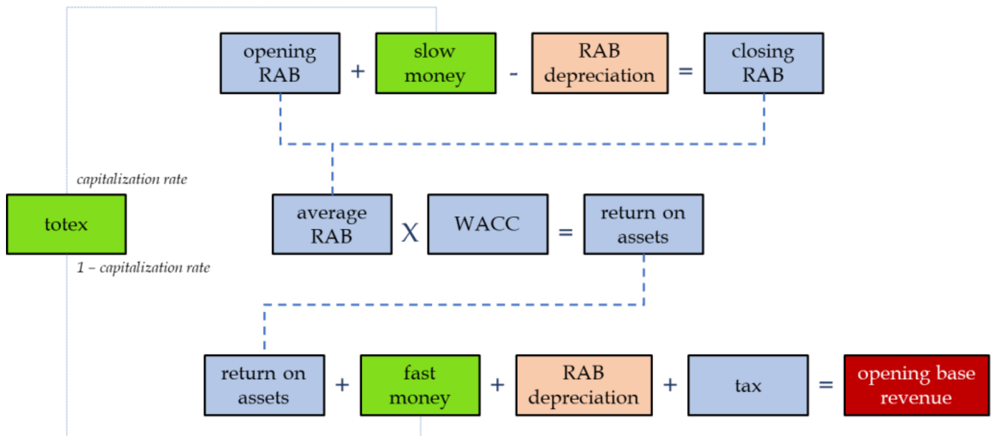
Totex approach

Under the traditional COS approach, only capital expenditures ("capex") can expand the utilities' RAB and allow them to increase their returns. Under a totex approach used by the UK's RIIO model and also used in this Study, instead of actual operating expenses ("opex") being passed through to ratepayers and actual capex added to the RAB, a set proportion of totex is funded through rates in the year incurred, called "fast money," and the remainder is added to the RAB and funded over time similar to capex, called "slow money." Fuel costs and expenses on Power Purchase Agreements ("PPAs") are not included in totex but passed through to ratepayers. The share of totex that constitutes slow money is determined by the totex capitalization rate, which is typically set at the beginning of the regulatory period based on the historical and forecasted split between capex and opex. Therefore, this rate can vary significantly between utilities as they do not have the same split between capex and opex.

Furthermore, utilities submit their forecast totex during the PBR proceeding and actual totex every year. They are also allowed to retain half of the amount they underspend as long as the underspend is due to efficiencies and that the outcomes agreed during the PBR proceeding are met. This means that the utilities cannot keep any underspends due to projects that did not materialize, or targets not achieved. At the end of the regulatory period, the PUC will review if the utilities have met the outcomes that they proposed at the start of the PBR regulatory period.

By splitting both capex and opex into slow and fast money as well as allowing utilities to keep the amount they underspend, the totex approach encourages utilities to use the most cost-effective solution. The totex approach eliminates the issue of favoring capex options if opex provides a better alternative. Figure 7 provides a graphical representation of how base revenues are calculated under the totex approach.

Figure 7. Base revenues under the totex approach



Additional O&M expenditure under the Outcomes-based PBR model would also include the costs incurred in filing capital and asset management plans, administration of PIMs, and retaining consultants in PBR-related proceedings.

PIMs

While additional and more detailed studies are necessary to evaluate the appropriate performance targets for the utilities, the Project Team has drawn up a potential list of performance measures. The assumed set of PIMs, or the rewards and penalties for each measure, for this regulatory model, is listed in Figure 8. Rewards and penalties for PIMs are based on whether utility performance falls outside the upper and lower bound targets for each PIM. If the actual performance falls short of the lower bound target, a penalty would be imposed for some of the PIMs; utilities are similarly rewarded for exceeding the upper bound target. If actual performance lies between the lower and upper bound targets, no penalty or incentive would be levied. The potential rewards and penalties are also capped, primarily to ensure the utilities' financial viability and to limit price volatility.

Figure 8. Potential outcomes and performance categories for Outcomes-based PBR

Performance outcome	Performance categories	Performance measures
Enhance customer experience	Customer satisfaction	• Billing accuracy • First contact resolution
	Service quality	• Telephone calls answered on time • New customers connected on time
	Customer engagement	• Number of consultations conducted
	Availability	• Generation availability • Equivalent forced outage factor • Equivalent forced outage factor demand
Improve utility performance	Reliability	• SAIFI • SAIDI • Number of times that power to a customer is interrupted
	Safety	• Number of general public incidents
	Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
	Asset management	• Transmission plan implementation progress • Distribution plan implementation progress
Receptive to public policies and goals	Connection of renewable generation	• Number of renewables connected on time
	Connection of DERs	• Number of DERs connected on time
	RPS target	• Percentage of renewables relative to total energy
	Demand response implementation	• Amount of demand response implemented
	Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
Healthy financial performance	Financial ratios	• Leverage: total debt to equity ratio • Liquidity: current ratio (current assets/current liabilities)

ESMs

The Outcomes-based PBR would also feature a symmetric ESM applied to overall utility earnings. The ESM would be applied to the utility's Return on Equity ("ROE") if it exceeded or fell short of the authorized level of ROE. ESMs typically feature a deadband – a set margin around the allowed ROE that would not result in any sharing of earnings. However, if actual ROE is above the upper bound of the deadband, the excess earnings are shared with the customers in pre-determined percentage.

ESM calculations – hypothetical utility

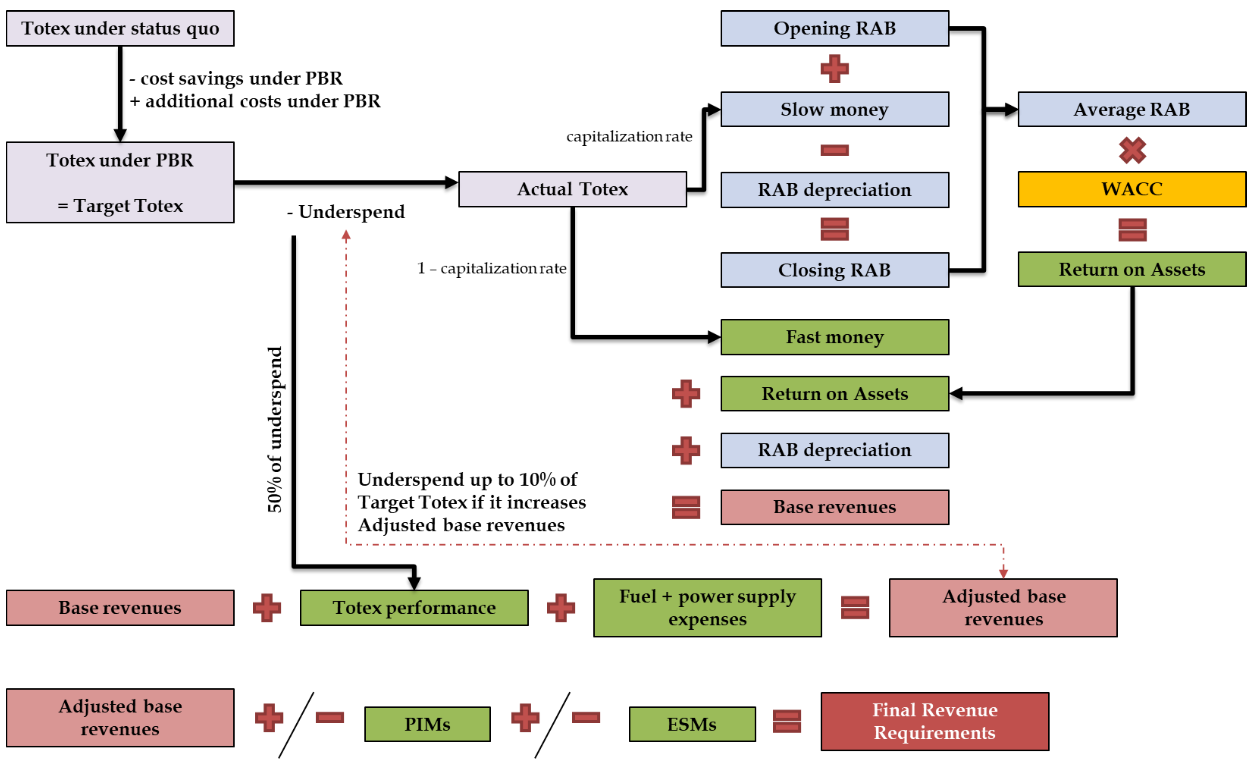
Rate base: $2,000; Leverage ratio: 50%; Equity's share of rate base: $1,000
Allowed ROE: 10%; Deadband: +/- 100 basis points

Net Income associated with allowed ROE: 10% X $1,000 = $100
Net Income within deadband (no ESM): $90 - $110 (ROE of 9% to 11%)

ESM – excess earnings if Net Income > $110 = actual Net Income - $110
ESM – insufficient earnings if Net Income < $90 = actual Net Income - $90

Similarly, if earnings are insufficient, the same percentage is collected from ratepayers in the subsequent regulatory period. The Project Team has assumed a deadband of 100 basis points above and below (200 basis points in total) the allowed ROE. An illustrative example of ESM calculations is shown in the text box above.

Figure 9. Revenue requirements calculations under Outcomes-based PBR



Note: A higher level of underspend would allow the utility to increase its totex performance earnings but also lower the base revenues due to reduced fast money and slow money. The Project Team assumes that the utility optimizes the level of underspend relative to target totex to maximize adjusted base revenues. For modeling purposes, the Project Team believes that the utility is only able to lower actual totex from its target level by a maximum of 10% per year without disrupting its essential functions. The ESMs included in the final revenue requirements for a given year reflect the excess/insufficient earnings from the previous regulatory period, spread over the current regulatory period.

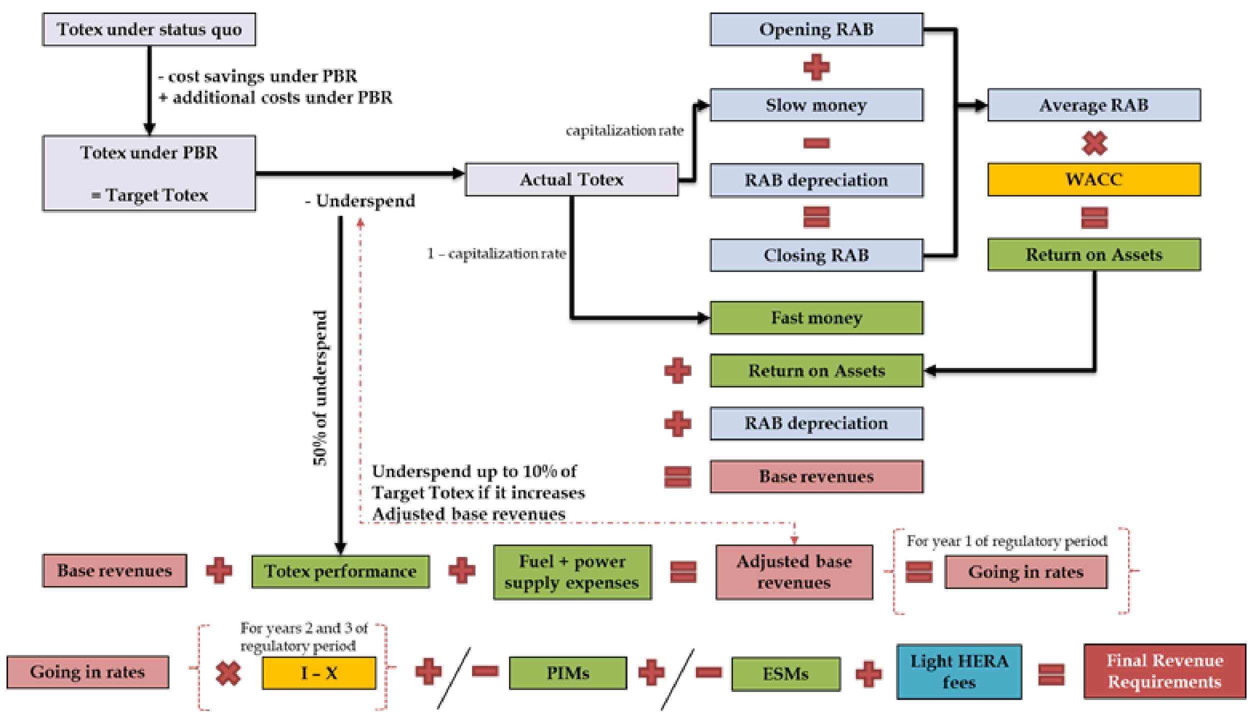
3.1.1.3 Conventional PBR + Light HERA

The Conventional PBR component of this model is different from the Outcomes-based PBR in a few key areas:

- a shorter regulatory period (3 years instead of 5 years);
- no requirement to file capital and asset management plans;
- fewer PIMs; and
- implementation of a revenue-cap approach.

Similar to Outcomes-based PBR, mechanisms such as totex, totex performance, pass through of fuel and PPA costs, PIMs, and ESMs are the same under the Conventional PBR; however, the PIMs under this model are less extensive. The target totex was set at the planned level of totex for that year under the status quo, adjusted for changes in costs under PBR. Once the base rates were obtained using the totex approach, the Project Team calculated the revenue-cap using an indexing formula based on subtracting expected productivity growth from Hawaii's projected inflation rate (the "I-X" approach). The projected base rate for the start of the regulatory period was used as the going-in rate and adjusted for the remainder of the regulatory period using the indexing formula. The final revenue requirements were calculated by adding PIMs, ESM, and Light HERA costs to the going-in rates. A summary of revenue requirement calculations under the Conventional PBR + Light HERA model is depicted in Figure 10.

Figure 10. Revenue requirements calculations under Conventional PBR + Light HERA



Note: The figure represents a general case for calculations. For the first year of a regulatory period, adjusted base revenues is taken as the going in rate. For subsequent years in that regulatory period, the going in rate is increased/decreased by (I – X) after each year.

Compared to the Outcomes-based PBR model, the Conventional PBR has fewer list of PIMs as shown in Figure 11.

Figure 11. Potential performance categories and measures under Conventional PBR

Performance categories	Performance measures
Availability	• Generation availability • Equivalent forced outage factor • Equivalent forced outage factor demand
Reliability	• SAIFI • SAIDI • Number of times that power to a customer is interrupted
Cost control	• Cost of final delivered energy to customers by rate class for each island system • Total cost per customer • Total cost per km of wires
Service quality	• Telephone calls answered on time • New customers connected on time
Customer engagement	• Number of consultations conducted
Competitive procurement	• Timely conduct of a competitive procurement • Cost savings in renewable generation procurement
RPS target	• Percentage of renewables relative to total energy • Number of renewables connected on time

3.1.1.4 Hybrid

The underlying approach to revenue requirement calculations under this model is similar to that in the Outcomes-based PBR model. However, the presence of an Integrated Grid Operator ("IGO") and a Distributed System Platform Provider ("DSPP") model for the utility changes some of the underlying costs.

IGO

The IGO's funding requirements are typically collected as fees from load-serving entities and generators. Ultimately, these costs are passed on to ratepayers in the form of increments to power supply expenses. For simplification, the Project Team added IGO's costs to revenue requirements separately instead of allocating it to the utilities and PPA expenses. With an IGO, the total operating costs for the utilities in two categories are reduced.

- **Power supply expenses**: with an IGO that oversees resource planning, procurement, and system operations, there is expected benefits from increased competition. Projected expenses to purchase power produced by Independent Power Producers ("IPPs") are anticipated to be lower under an IGO and result in savings to the ratepayers and lower revenue requirements to the utilities.

- **System operations and dispatch**: with an IGO, the utilities are no longer expected to incur O&M expenses related to transmission and distribution ("T&D") planning, dispatch, and system operations as these functions would be transferred to the IGO.

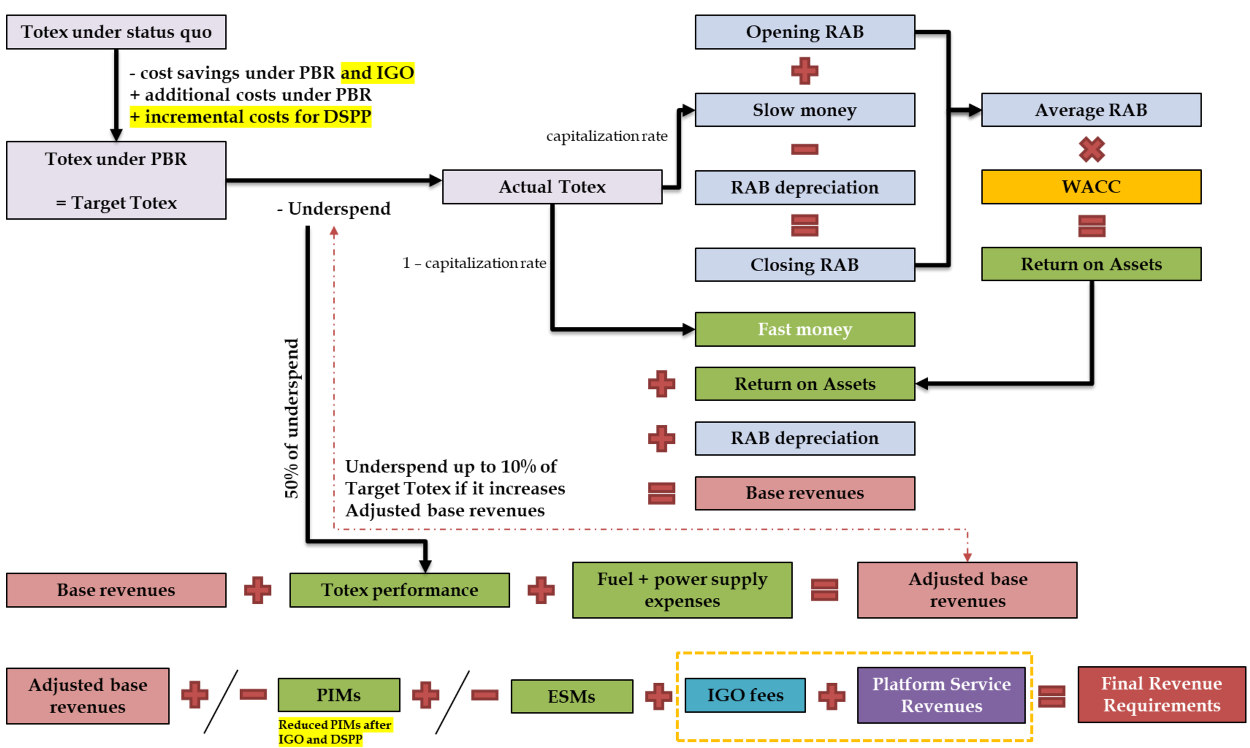
Once an IGO is operational, the Project Team assumes that the utilities no longer get rewarded or penalized for the Competitive procurement, RPS targets, and DER connection PIMs since the utilities do not fully control these functions once these responsibilities are undertaken by the IGO.

DSPP

The setup and operational costs of a distributed platform under this model are added to the target totex under the Outcomes-based PBR model. Furthermore, the utilities are expected to earn Platform Service Revenues ("PSRs") under this model. The final revenue requirements also incorporate the projected PSR revenues as an offset to the base revenues.

The approach to calculating revenue requirements under the Hybrid model is largely similar to that under the Outcomes-based PBR model; the differences between the two models are highlighted in Figure 12.

Figure 12. Revenue requirements calculations under the Hybrid model



3.1.2 Co-op

As described previously in the reports for Tasks 1.4.2 and 1.6.1/1.6.3, an electric co-op's revenue requirements are determined using a Times Interest Earned Ratio ("TIER") level. The ratio measures how many times a co-op can cover its interest expenses from its pre-tax earnings. Although the United States Department of Agriculture's ("USDA") Rural Utilities Service ("RUS") loan agreements require a minimum TIER of 1.25 for distribution utilities, the PUC sets the TIER level for KIUC at 2.00.[8] Revenue requirements for a co-op are calculated using the following formula:

$$Revenue\ Requirement = Interest\ Expense * TIER + Operating\ Expense$$

Besides the TIER-based calculation, costs for co-ops also differ from IOUs on the following items:

- **Cost of equity**: co-ops raise equity from their members in the form of patronage capital. Therefore, the cost of equity for co-ops is effectively zero.

- **Cost of debt**: co-ops receive loans from RUS and other entities such as the Cooperative Finance Corporation ("CFC") at below-market rates.

- **Taxes**: co-ops have a tax-exempt status federally and are only required to pay state income taxes on their revenues.

This underlying calculation mechanism will apply to all the regulatory models considered for Kauai County, with slight adjustments for each model.

i) **Lighter PUC Regulation** – a "softer touch" regulatory approach to KIUC is assumed to lower the regulatory expenses for KIUC by 75% from its current levels by reducing their regulatory burden.

ii) **HERA** – a surcharge for HERA is added to the final revenue requirements for KIUC calculated using the status quo approach.

iii) **IGO** – KIUC's system operations and dispatch costs are removed from the calculation of their operating expenses under the status quo. An IGO fee is added to the final revenue requirements for KIUC. For simplification, the Project Team assumed that this fee is set at the level required to recover the IGO's funding requirements which would have been collected from both KIUC and other generators and ultimately passed through to ratepayers.

---

[8] Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009.

3.2 Assumptions used for revenue requirement calculations

This section provides a summary of the assumptions used to estimate the key components of revenue requirements under each model for each county. They have been sourced from the utilities' public filings where possible and supplemented with data collected from other publicly available research and filings from other jurisdictions.

3.2.1.1 Status Quo – HECO/MECO/HELCO

Parameter	Assumptions
Capital structure and cost of capital	The HECO Companies are capitalized with a combination of: - short-term debt - long-term debt - hybrids - preferred stock - common stock The proportion and rate of return for each instrument were obtained from the current or most recent HECO/MECO/HELCO rate cases (Docket No. 2016-0328, Docket No. 2017-0150, Docket No. 2015-0170).
Effective income tax rate	For 2017, the effective state and federal income tax rates, including the effect of state income tax on federal tax rate, were obtained from HECO, MECO, and HELCO rate cases. From 2018 onwards, the analysis assumed gross federal income tax rate of 21% to be consistent with the current tax rate.
Taxes other than income taxes (revenue taxes)	The rates for public service tax, PUC fees, and franchise tax were obtained from the IOU rate cases. The payroll tax was estimated as a % of O&M labor expense.
Hawaii cost index (vs. the overall United States)	The Project Team created an index to scale the US-wide levelized costs of energy forecasts from NREL to Hawaii-specific forecasts, based on EIA – State Energy Data System 2016 (motor gasoline average price, all sectors). This was applied to forecasts of technology costs to ensure that they reflected the higher costs in Hawaii relative to the mainland.
Power plant life (years)	The useful service lives of power plant assets by technology (solar, wind, hydro) were assumed based on industry standards used by EIA.
Plant depreciation rates	The Project Team obtained depreciation rates from rate cases for the following asset categories: - Production - T&D - General - Vehicles
Regular plant retirements	The Project Team estimated plant retirements as a % of beginning-of-year plant balances from rate cases, based on an average of 2011-2015 data.

717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com
Gabriel Roumy/Utsav Dhoj Adhikari
617-933-7225
gabriel@londoneconomics.com

Inflation rate	2%
Annual plant O&M cost escalation above and beyond the generic 2% inflation	Estimated at 0.25% based on industry standards.
Annual capacity factor decrease	Estimated at 1% for renewables and 5% for thermal, to align generation by fuel type with HECO's projections in the PSIP.
Thermal plant efficiency loss	Estimated at 2% every five years, to align generation by fuel type with HECO's projections in the PSIP.

3.2.1.2 Outcomes-based PBR

Parameter	Assumptions
Regulatory period	5 years
Start year	2020 based on the Hawaii Ratepayer Protection Act
PBR transition costs	Annual amount was estimated in Task 2.3.1 using Alberta Utility Commission costs and applied for 2018 and 2019, assuming a two-year transition period.
Utility capital cost and structure	Same as status quo and assumed to remain constant throughout the forecast horizon. The fixed capital costs and structure approach was used for simplification and was based on the assumption that the design and implementation of PBR, especially in terms of feasibility of metrics and size of rewards and penalties, are conducted with regard to minimizing the impact on financial markets.
Capitalization rate (for totex)	Historical average ratio of Capex/(Capex+Opex) between 2017 and 2019 (3 years preceding the PBR regime). Opex excludes fuel costs and PPA expenses.
Consultants' fees for PBR	Consultants' fees for PBR proceedings of 3 Alberta utilities in 2013 CAD, converted and inflated to 2017 USD; based on LEI's experience
PIMs administration costs for utility	Average of three categories of administrative costs for HECO from its rate case filings (used as an indication of utilities' program administration costs): - administer business plans - manage safety program and training - DC Fast Charger operations
Costs to develop capital and asset management plan	HECO's costs to develop business plans, according to details on its O&M cost categories from its rate case filing.
PIMs rewards/penalties	Rewards and penalty levels based on current PIMs in Hawaii for reliability, service quality, demand response implementation, and cost savings in renewable procurement. See Section 3.2.1.6
Cost savings for utility	3% reductions for the following cost categories (based on efficiency gains from competition used for Single Buyer):

	- cost of final delivered energy to customers - total cost per customer - total cost of wires
Target totex	Totex under status quo, adjusted for changes in costs under PBR.
Additional totex savings	Utilities may also make additional totex savings if it improves their revenue requirements. Project Team assumes that underspends are due to efficiencies and therefore, the utilities could keep half of the underspend below the target totex. It is assumed that the utility would not underspend by more than 10% of the target totex to provide essential functions.
ESM	Deadband is +/- 100 basis points. Sharing of excess or insufficient earnings with customers is 50%. Note: the deadband and earnings sharing levels are the Project Team's assumptions based on a review of other jurisdictions with PBR. Excess/insufficient earnings from one regulatory period are included in the next regulatory period, spread evenly across the number of years.

3.2.1.3 Conventional PBR + Light HERA

Parameter	Assumptions
Light HERA costs	HERA funding requirements were estimated in Task 2.2.1. Startup costs and annual funding requirement (on a $/kWh basis) obtained from other reliability entities and scaled to Hawaii. Light HERA funding requirement assumed to be half of that of a full HERA.
Start year	2020
Conventional PBR	
Regulatory period	3 years
Start year	2020 based on the Hawaii Ratepayer Protection Act
PBR transition costs	Same as for Outcomes-based PBR
I	Five-year (2013-2017) average growth rate of implicit price deflator for GDP for Hawaii from DBEDT's 2017 State of Hawaii Data Book – 2.10%
X	Multifactor productivity growth between 2008 and 2014 for 86 US power distributors, from a study by US DOE's Grid Modernization Consortium – 0.22%
Utility WACC	Same as status quo
Capitalization rate (for totex)	Capex/(Capex+Opex) between 2017 and 2019 (3 years preceding the PBR regime). Opex excludes fuel costs and PPA expenses.
Consultants' fees for PBR	Consultants' fees for PBR proceedings of 3 Alberta utilities in 2013 CAD, converted and inflated to 2017 USD.
PIMs administration costs for utility	Average of three categories of administrative costs for HECO from its rate case filings (used as an indication of utilities' program administration costs): - administer business plans

	- manage safety program and training - DC Fast Charger operations
PIMs rewards/penalties	PIMs rewards/penalties are the same as Outcomes-based PBR. See Section 3.2.1.6
Cost savings for utility	3% reductions for the following cost categories (based on efficiency gains from competition used for Single Buyer): - cost of final delivered energy to customers - total cost per customer - total cost of wires
Target totex	Totex under status quo and adjusted for changes in costs PBR.
Additional totex savings	Utilities may also make additional totex savings if it improves their revenue requirements. Project Team assumes that utilities can keep 50% of the underspend below the target totex. The utility cannot (or will not) underspend by more than 10% of the target totex to provide essential functions.
ESM	Deadband is +/- 100 basis points. Sharing of excess or insufficient earnings with customers is 50%. Note: the deadband and earnings sharing levels are the Project Team's assumptions based on a review of other jurisdictions with PBR. Excess/insufficient earnings from one regulatory period are included in the next regulatory period, spread evenly.

3.2.1.4 Hybrid

Parameter	Assumptions
Outcomes-based PBR	Same as standalone Outcomes-based PBR (see above)
IGO costs	Startup and annual operating costs (on a $/MWh basis) from 2004 FERC report on RTOs and adjusted for inflation. Lower expenses from greater technical knowledge and improved technology assumed to be offset by smaller scale of Hawaii.
IGO start year	2023 For Maui County, the Project Team assumed that an IGO is only established on Maui island, due to the small size of the other two islands in the county
Utility cost reductions	Planning and dispatch operations costs for utility assumed to be 0 after IGO is functional. Power supply expenses assumed to decrease by 3% yearly from efficiency gains through increased competition.
DSPP start year	2028
DSPP costs	Costs for National Grid's DSP REV demonstration project at Buffalo Niagara Medical Campus scaled to Hawaii based on DER capacity.
Platform Service Revenues	Year 1 = 2020 PIMs under Outcomes-based PBR Revenues doubling time = 5 years

	Source – summary of staff white paper for NY REV (http://projects.exeter.ac.uk/igov/wp-content/uploads/2016/05/IGov-Introduction-to-DSO-vs-DSP.pdf)

3.2.1.5 KIUC

Parameter	Assumptions
Lighter PUC Regulation	
Lighter regulation start year	2020 based on the legal requirements needed.
Current regulatory expenses	From KIUC's 2017 Annual Report to the PUC.
Reduction in regulatory expenses	75% based on the Team's assumption of lower filing requirements.
HERA	
HERA start year	2020 based on the requirements needed to set up the HERA.
Startup costs and annual funding requirement	HERA funding requirements were estimated in Task 2.2.1. Startup costs and annual funding requirement (on a $/kWh basis) obtained from other reliability entities and scaled to Hawaii.
IGO	
IGO start year	2023 based on requirements needed to set up the IGO.
IGO costs	Startup and annual operating costs (on a $/MWh basis) from 2004 FERC report on RTOs. Lower expenses from greater technical knowledge and improved technology assumed to be offset by smaller scale of Hawaii.
Utility cost reductions	Planning and dispatch expenses for utility assumed to be 0 after IGO is functional since IGO would take over these functions.

contact:
Gabriel Roumy/Utsav Dhoj Adhikari
617-933-7225
gabriel@londoneconomics.com

3.2.1.6 PIMs

The Project Team has proposed a potential list of PIMs for the PBR models. As the table below indicates, the list of PIMs is more extensive for the Outcomes-based PBR model. Independent entities like IGO in the hybrid model take on some of the responsibilities of overseeing the functions relevant to the PIMs for operations and interconnection. Since the utilities do not fully control performance under those categories, they are no longer rewarded or penalized for those metrics once the IGO is active. The rewards and penalties for the PIMs are set based on the current PIMs in Hawaii for reliability, service quality, demand response implementation, and cost savings in renewable procurement. For each additional PIM proposed for the recommended models, the Project Team assigned the reward and penalty levels based on its comparability to an existing PIM.

There are three categories of reward and penalty levels:

- **Benchmarked to rate base** – for any given year, the reward or penalty level for a performance metric is set as a certain percentage of the equity's share of rate base for that year. Since the capital structure is assumed to be constant throughout the forecast horizon, the reward and penalty levels are essentially a fixed percentage of the RAB in that year. Currently, this type of rewards/penalties is used for reliability and service quality PIMs.

- **Shared savings** – for performance metrics that are tied to reducing a certain category of costs, shared savings allow the utility to earn back a fixed percentage of the actual cost reductions achieved. This mechanism incents the utility to achieve larger cost reductions since their rewards will be correspondingly greater. The existing PIM for cost savings in renewable generation procurement utilizes this approach.

- **One-time incentive payment** – the utility receives a one-time incentive payment to implement a certain program or achieve particular targets. In Hawaii, this approach is used for demand response implementation.

PIM	Reward/Penalty	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Generation availability	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Equivalent forced outage factor	- no reward - 0.20% of common equity share of rate base	✓	✓	✓

Equivalent forced outage factor demand	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
SAIFI	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
SAIDI	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Number of interruptions	- no reward - 0.20% of common equity share of rate base	✓	✓	✓
Cost of final delivered energy	- 20% shared savings - no penalty	✓	✓	✓
Total cost per customer	- 20% shared savings - no penalty	✓	✓	✓
Total cost of wires	- 20% shared savings - no penalty	✓	✓	✓
Telephone calls answered on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
New customers connected on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
Number of consultations conducted	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓
Timely conduct of competitive procurement	- no reward - 0.20% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Cost savings in renewable generation procurement	- 20% shared savings - no penalty	✓	✓	✓ (before IGO starts)

Percentage of renewables relative to total energy	- no reward - 0.20% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Number of renewables connected on time	- reward and penalty both 0.08% of common equity share of rate base	✓	✓	✓ (before IGO starts)
Billing accuracy	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
First contact resolution	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Number of general public incidents	- no reward - 0.20% of common equity share of rate base	✓	×	✓
Transmission plan implementation progress	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Distribution plan implementation progress	- reward and penalty both 0.08% of common equity share of rate base	✓	×	✓
Timely processing of DER interconnection applications	- one-time incentive payment of $500,000 - no penalty	✓	×	✓ (before IGO starts)
Amount of demand response implemented	- one-time incentive payment of $500,000 - no penalty	✓	×	✓
Leverage: total debt to equity ratio	- no reward - 0.20% of common equity share of rate base	✓	×	✓
Liquidity: current ratio	- no reward - 0.20% of common equity share of rate base	✓	×	✓

3.3 Revenue requirements results

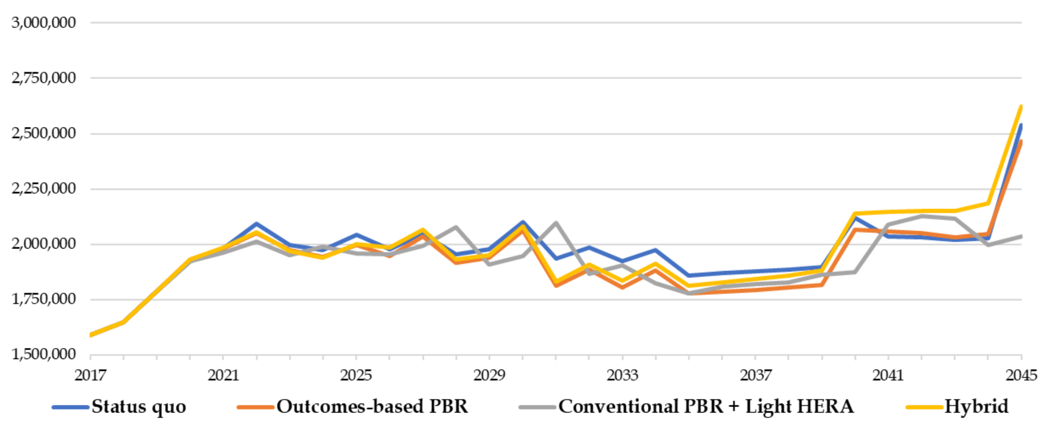
This section summarizes the projections of revenue requirements under various regulatory models in each county, including a discussion of the drivers of projected increases and decreases. The Project Team also conducted sensitivity analyses to evaluate the impact of changing underlying assumptions on overall projections.

A change in regulatory model results in savings relative to the status quo, in Net Present Value ("NPV") terms, on Honolulu, Hawaii, and Maui Counties. The status quo model results in the highest revenue requirements for Hawaii County. For Kauai County, Lighter PUC Regulation results in the lowest revenue requirements while the HERA model is the highest. The subsequent subsections will discuss these in detail.

3.3.1 HECO

The Outcomes-based PBR model has the lowest projected revenue requirements over the forecast horizon, in Net Present Value ("NPV") terms, and the status quo has the highest. The annual growth rate of revenue requirements between 2018 and 2045 under the Conventional PBR + Light HERA model is about half of that under the status quo. Relative to the status quo, all three recommended models are expected to generate savings to ratepayers: $399 million under the standalone Outcomes-based PBR model, $387 million under the Conventional PBR + Light HERA model, and $153 million under the Hybrid model. Projected revenue requirements are highest under the status quo for a majority of years in the 2020s and 2030s; from 2040, forecasted revenue requirements are highest under the Hybrid model.

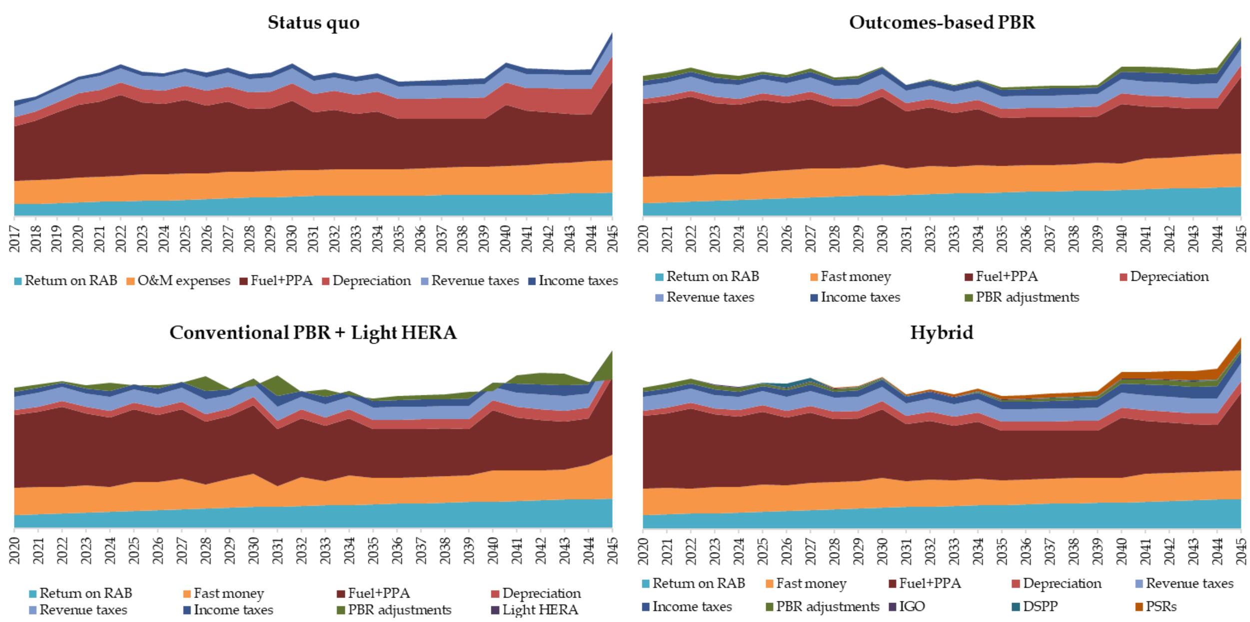
Figure 13. Honolulu County revenue requirements by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.57% - $ millions			
$22,410	$22,011	$22,023	$22,257
Revenue requirements growth (CAGR): 2018 - 2045			
1.61%	1.50%	0.78%	1.73%

Compared to the status quo, return on RAB is projected to be higher under the other three models due to the faster growth of RAB under the totex approach. The fast money under the three PBR-based models is also expected to be lower than the O&M expense under the status quo due to anticipated efficiencies. Of the three potential models studied, fast money is expected to be highest under the standalone Outcomes-based PBR model because it includes additional administrative costs to the utility compared to a Conventional PBR model; in the Hybrid model, these costs are offset by the transfer of the utility's system planning and dispatch functions to an IGO. PBR adjustments, which includes totex performance, PIMs, ESM, and revenue cap (for Conventional PBR), are also projected to be higher under the Outcomes-based PBR model because they are more extensive than under the other models. Rewards and penalties under some PIMs are phased out under the Hybrid model once the IGO and DSPP become operational. Conventional PBR includes fewer PIMs as well as a revenue cap which restricts the growth of revenues. For the Hybrid model, DSPP-related investment and operating costs are not expected to be significant compared to overall revenue requirements, but platform service revenues are forecast to be an important component of revenue requirements from 2035 onwards.

Figure 14. Composition of revenue requirements forecast – Honolulu County



The Project Team conducted sensitivity analyses with respect to a change in the WACC or totex capitalization rate, as shown in Figure 15 and Figure 16. A change in WACC has a much lower impact in the medium and long runs on revenue requirements under the PBR-based models, especially both models with Outcomes-based PBR. A 1 percentage-point increase in WACC would increase the projected annual revenue requirements by, on average, $51 million under the status quo model, $9 million under the Outcomes-based PBR model, $29 million under the Conventional-PBR + Light HERA model, and $9 million under the Hybrid model.

The totex approach is heavily dependent on the capitalization rate used to categorize expenses as slow money and fast money. The projected impact of a change in the totex capitalization rate is similar for both Outcomes-based PBR and Hybrid models. A 3 percentage-point increase in totex capitalization rate would increase the projected annual revenue requirements by, on average, $29 million under the Outcomes-based PBR model, $20 million under the Conventional-PBR + Light HERA model, and $29 million under the Hybrid model.

Figure 15. Sensitivities to change in WACC – Honolulu County revenue requirements forecast ($000s, nominal)

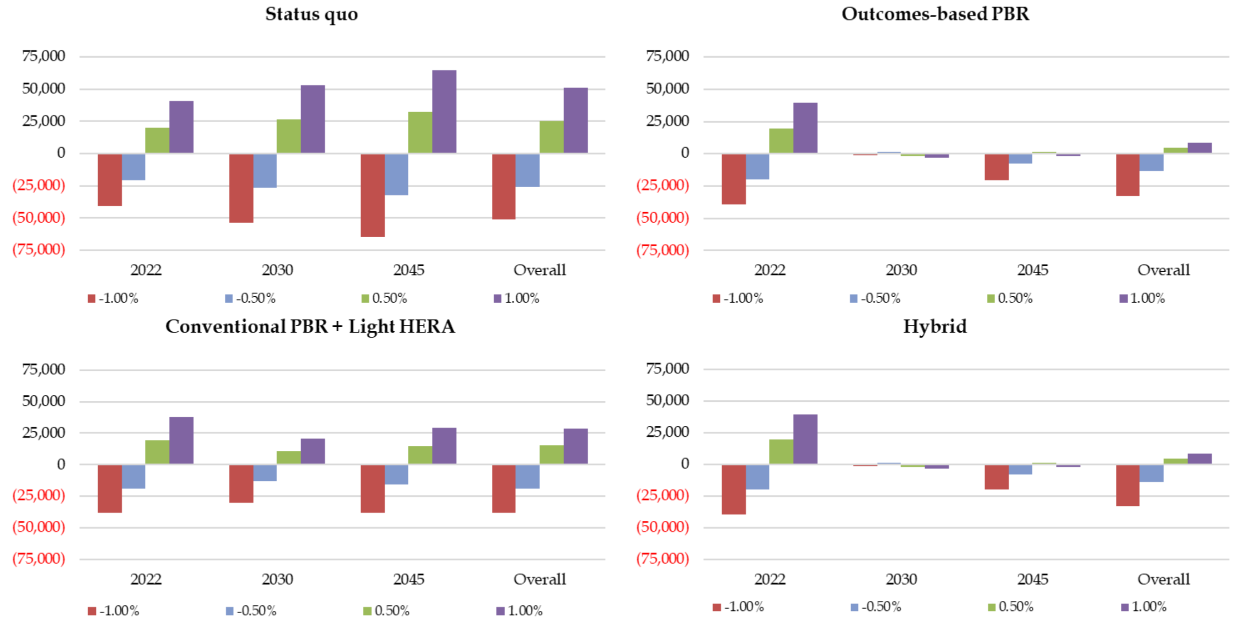
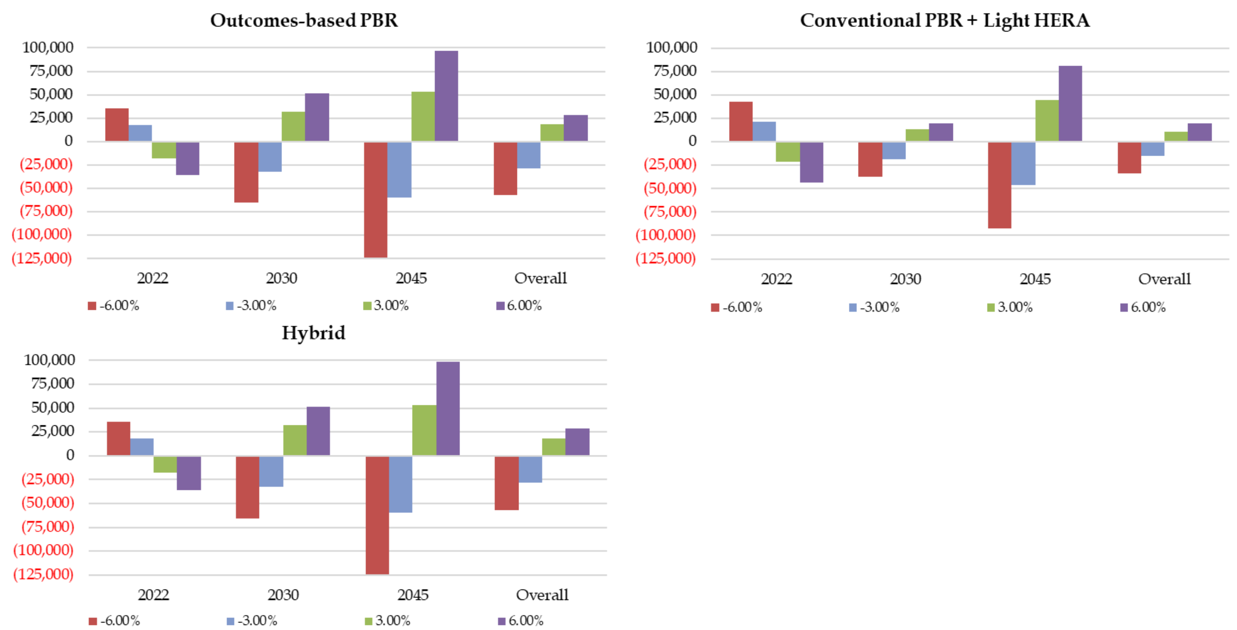


Figure 16. Sensitivities to change in totex capitalization rate – Honolulu County revenue requirements forecast ($000s, nominal)

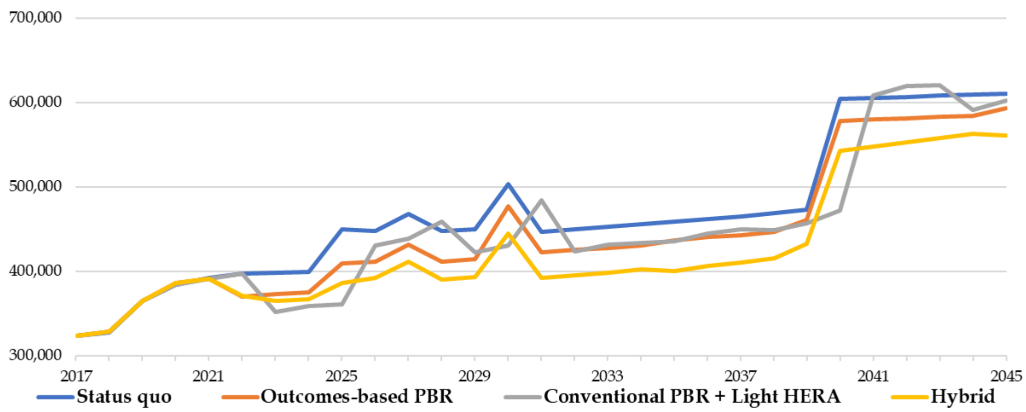


The direction of the impact is inverted over time. Increasing the totex capitalization rate decreases revenue requirements initially but eventually results in higher revenue requirements in the longer term. This change occurs because a higher totex capitalization rate implies lower fast money for the present but a larger asset base on which to earn a return over the long term.

3.3.2 HELCO

Revenue requirements under the three PBR-based models are expected to be substantially lower that the status quo. Over the entire forecast horizon, the Hybrid model has the lowest projected revenue requirements, in Net Present Value ("NPV") terms, and the status quo model has the highest. Relative to the status quo, The standalone Outcomes-based PBR saves $341 million, the Conventional PBR + Light HERA model saves $329 million, and the Hybrid model saves $506 million in NPV terms over the forecast horizon.

Figure 17. Hawaii County revenue requirements forecast by regulatory model ($000s, nominal)

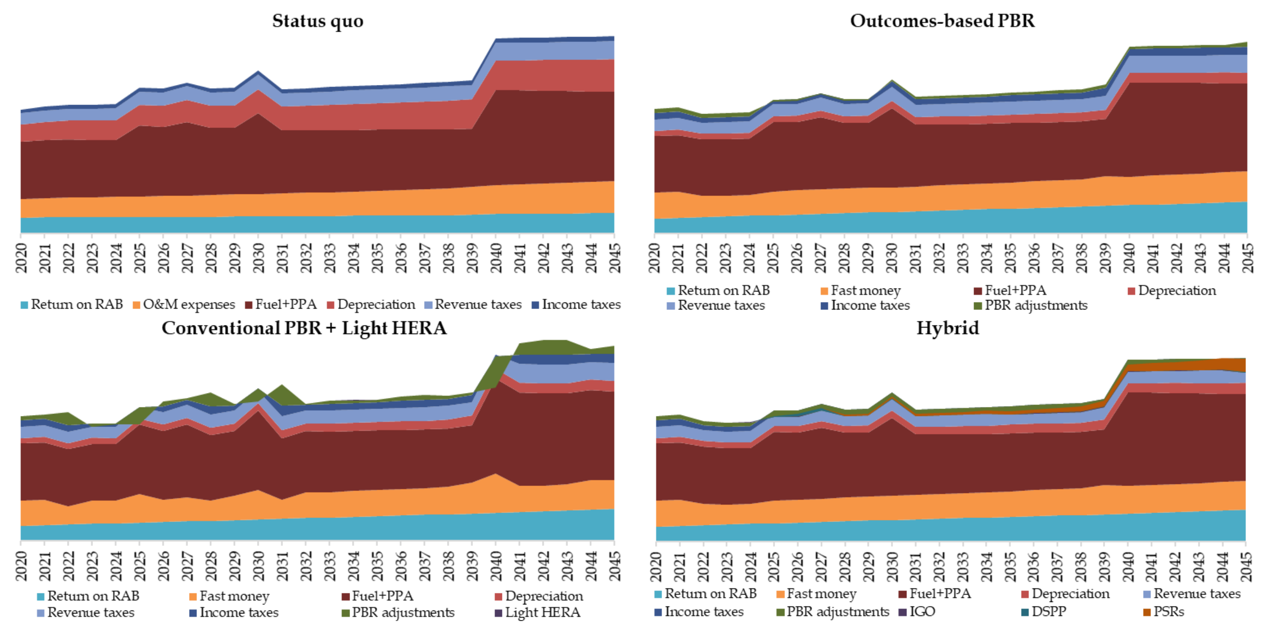


Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.79% - $ millions			
$4,870	$4,650	$4,659	$4,477
Revenue requirements growth (CAGR): 2018 - 2045			
2.33%	2.22%	2.27%	2.00%

As on Honolulu County, the projected return on RAB is lower whereas the O&M expenses, relative to the fast money component under the PBR models, are higher under the status quo because RAB is expected to grow faster due to the totex approach and efficiency improvements through PBR lower some operating expenses. Projected reductions in fuel and PPA costs under the recommended models average $4 million a year from 2020 onwards or an NPV of $39 million.

All three recommended models are also expected to substantially reduce totex over the forecast horizon. The estimated reductions in totex relative to the status quo, in NPV terms, was $263 million under the Outcomes-based PBR model, $267 million under the Conventional PBR + Light HERA, and $309 million under the Hybrid model.

Figure 18. Composition of revenue requirements – Hawaii County



The sensitivity analyses in Figure 19 and Figure 20 show that the impact of a change in WACC is different for the four regulatory models, especially in the long run. For the status quo and Conventional PBR + Light HERA models, the change in revenue requirements is proportionate to the change in WACC. For Outcomes-based PBR and Hybrid models, this is true for the short-term; in the medium- and long-term, forecasted revenue requirements in 2030 and 2045 were lower even with an increase in WACC. Over time, the impact of the ESM offset the incremental revenue requirements from a higher WACC.

With a one percentage-point increase in WACC, the annual revenue requirements are expected to increase by, on average, $10 million under the status quo model, $2 million under the Outcomes-based PBR model, $6 million under the Conventional-PBR + Light HERA model, and $2 million under the Hybrid model.

Increasing the totex capitalization rate decreases revenue requirements initially but eventually results in higher revenue requirements in the longer term because a higher capitalization rate results in lower fast money and a higher RAB; over time, the returns on a larger RAB more than offset the decrease in slow money. A 3 percentage-point increase in capitalization rate would increase the projected average annual revenue requirements by $6 million under the Outcomes-based PBR model, $3 million under the Conventional-PBR + Light HERA model, and $6 million under the Hybrid model.

Figure 19. Sensitivities to change in WACC – Honolulu County revenue requirements forecast ($000s, nominal)

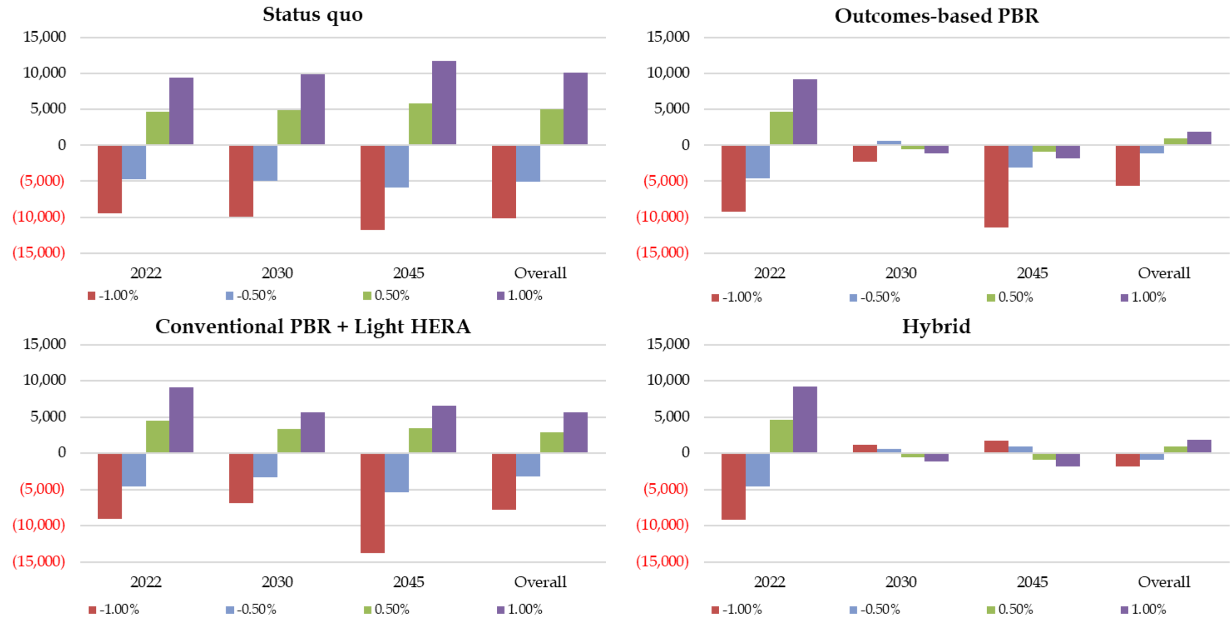
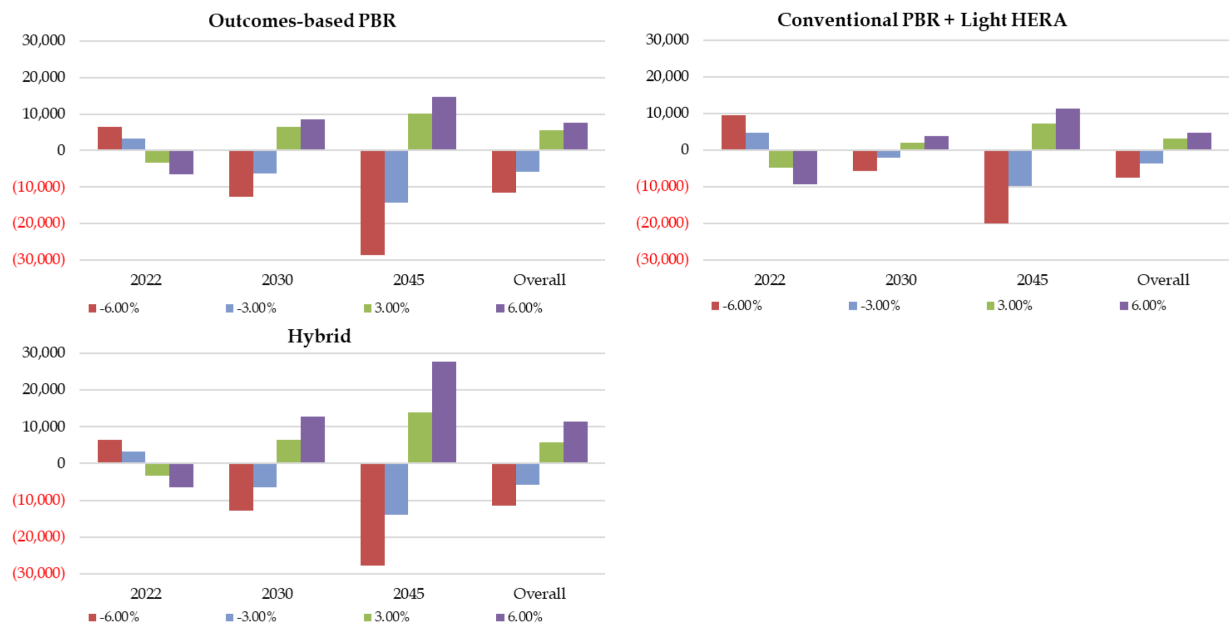


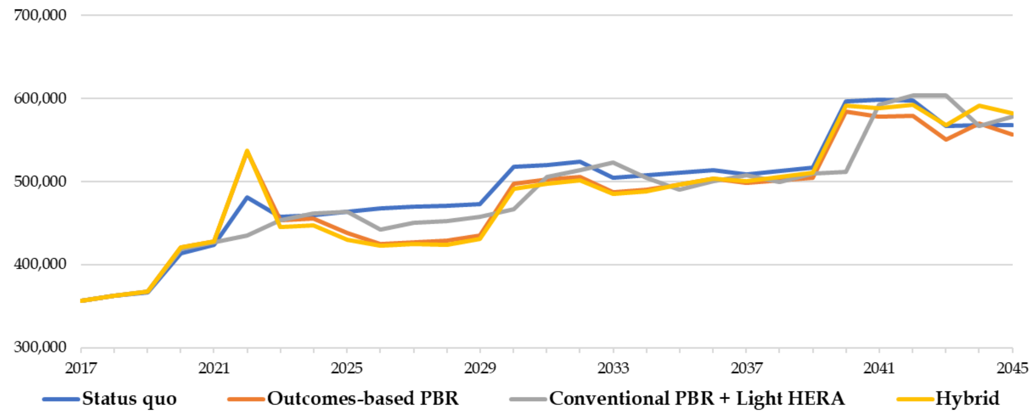
Figure 20. Sensitivities to change in totex capitalization rate – Hawaii County revenue requirements forecast ($000s, nominal)



3.3.3 MECO

Compared to the status quo, all three recommended models have lower forecasted revenue requirements. Overall, the Hybrid model has the lowest projected revenue requirements over the forecast horizon, in NPV terms, driven by lower fuel and PPA expenses. Relative to the status quo, the standalone Outcomes-based PBR saves $108 million, the Conventional PBR + Light HERA model saves $112 million, and the Hybrid model saves $119 million in revenue requirements over the forecast horizon (in NPV terms).

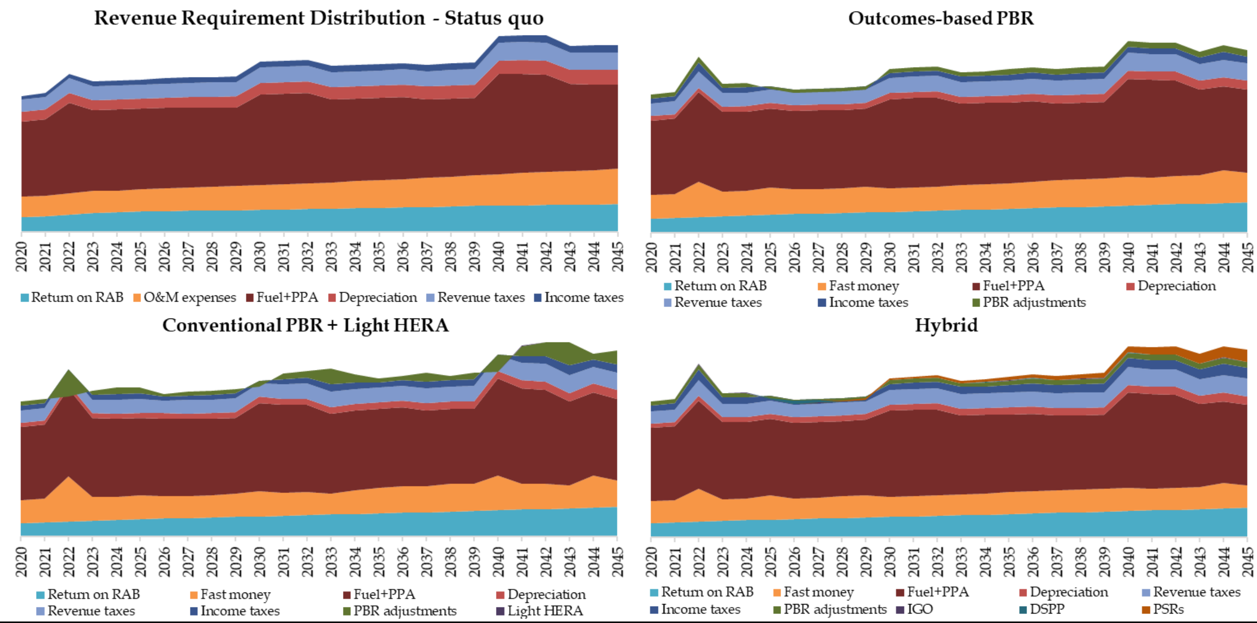
Figure 21. Maui County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Outcomes-based PBR	Conventional PBR+Light HERA	Hybrid
NPV (2018-2045) at 7.43% - $ millions			
$5,438	$5,330	$5,326	$5,319
Revenue requirements growth (CAGR): 2018 - 2045			
1.68%	1.59%	1.74%	1.77%

The composition of revenue requirements as shown in the graphs in Figure 22 is similar to those for Honolulu and Hawaii Counties. Return on the RAB is projected to be a growing component under the PBR models. The fast money component under the three PBR models is initially higher than O&M expenses under the status quo; over the forecast horizon, fast money is lowest under the hybrid model. Projected reductions in fuel and PPA costs under the recommended models average $4 million a year from 2020 onwards or an NPV of $37 million. Compared to the status quo, the recommended models are expected to lower totex by $271 million under the Outcomes-based PBR model, $276 million under the Conventional PBR + Light HERA, and $311 million under the Hybrid model.

Figure 22. Composition of revenue requirements forecast – Maui County



The sensitivity analyses in Figure 23 show that a change in WACC has a more significant impact on the status quo model than the three PBR models because the ESM component of PBR offsets the additional revenue from a higher WACC. A 1 percentage-point increase in WACC is expected to increase the average annual revenue requirements by $13 million under the status quo model, compared to $8 million under the Outcomes-based PBR model, $9 million under the Conventional-PBR + Light HERA model, and $8 million under the Hybrid model. A 3 percentage-point increase in capitalization rate would increase the projected average annual revenue requirements by $2 million under all three recommended regulatory models.

Figure 23. Sensitivities to change in WACC – Maui County revenue requirements forecast ($000s, nominal)

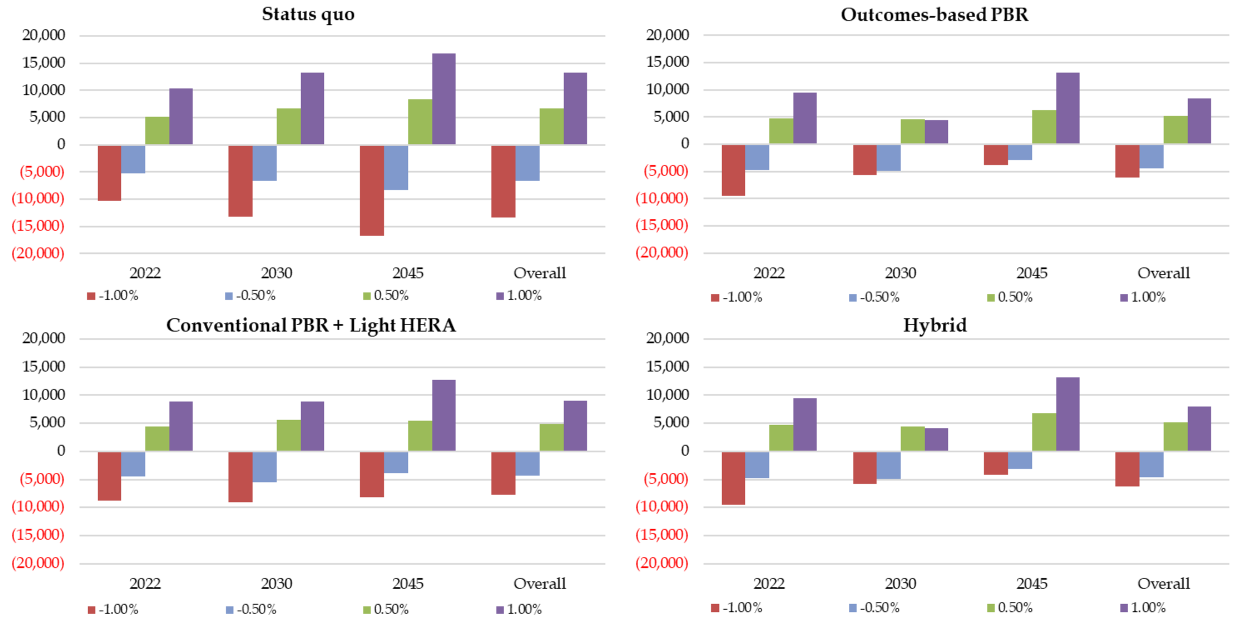
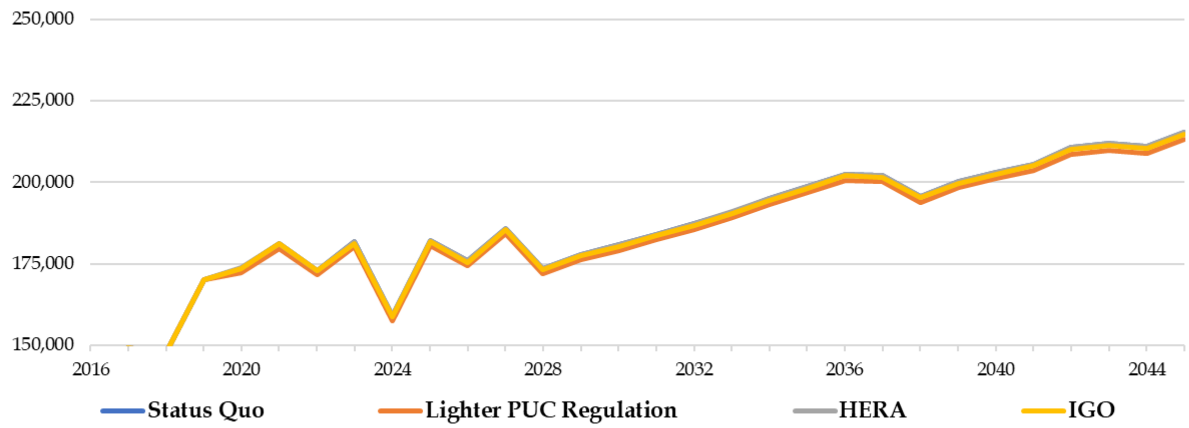


Figure 24. Sensitivities to change in totex capitalization rate – Maui County revenue requirements forecast ($000s, nominal)

3.3.4 KIUC

The revenue requirements in Kauai County are projected to be very similar under all regulatory models. Ratepayer savings under the Lighter PUC Regulation model relative to the status quo is expected to grow gradually from 0.7% in 2021 to 1% in 2045. The HERA and IGO models have an insignificant impact on revenue requirements: after the initial expenditure, projected revenue requirements are 0.01% higher under the HERA model and 0.05% lower under the IGO model. Over the forecast horizon and at 5% discount rate, the Lighter PUC Regulation model is expected to generate $21 million in savings relative to the current model; the additional costs of the HERA model and the savings from an IGO model are both forecast to be under $0.7 million.

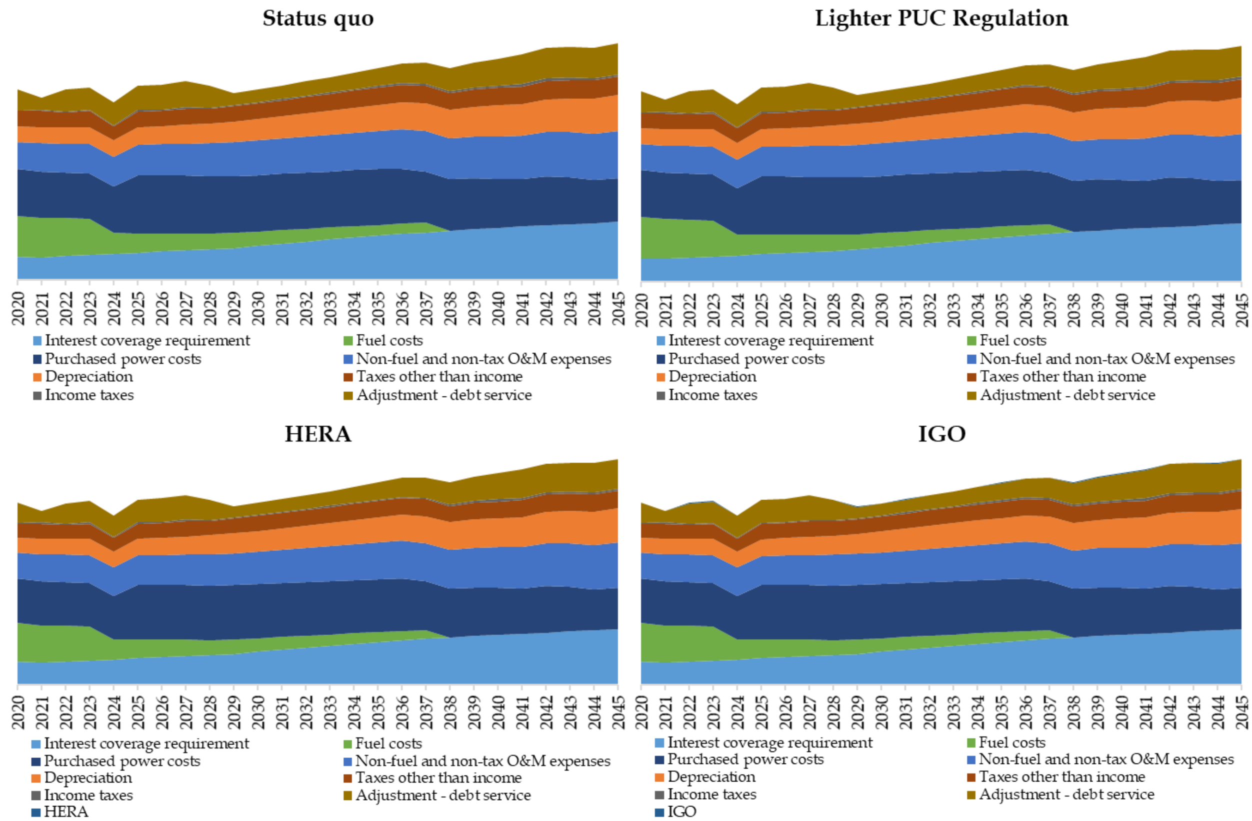
Figure 25. Kauai County revenue requirements forecast by regulatory model ($000s, nominal)



Status quo	Lighter PUC Regulation	HERA	IGO
NPV (2018-2045) at 5% - $ millions			
$2,722	$2,701	$2,722	$2,717
Revenue requirements growth (CAGR): 2018 - 2045			
1.40%	1.36%	1.40%	1.39%

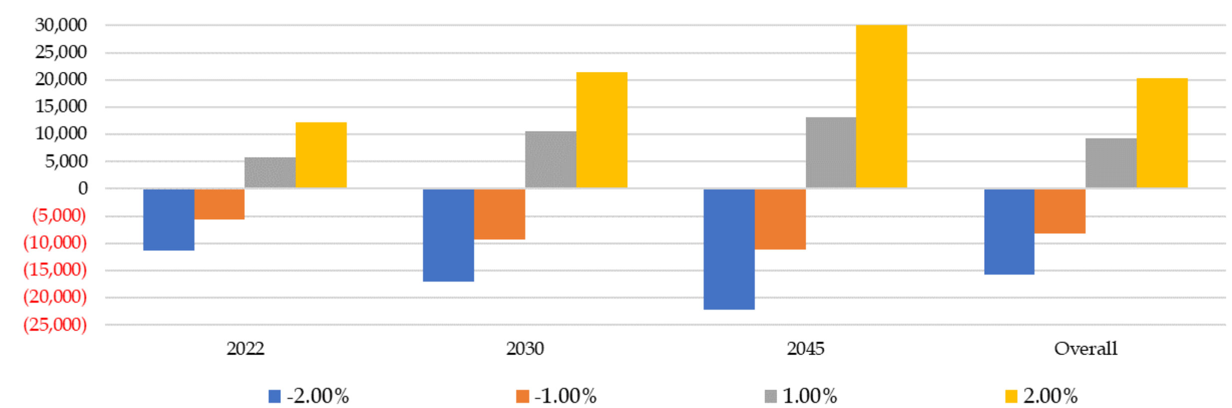
The composition of revenue requirements is virtually identical under all four regulatory models considered for Kauai County; the impact of lower regulatory expenses, HERA, and IGO is barely discernible. Regulatory expenses were only about 1% of total revenue requirements in the status quo model in 2017 and therefore have a small impact. Overall, the projected near-term increase in revenue requirements is driven largely by anticipated increases in purchased power costs as new capacity comes online, as shown in Figure 26.

Figure 26. Composition of revenue requirements forecast – Kauai County



The Project Team's sensitivity analyses conducted for Kauai County assessed the impact of a change in interest rate on long-term debt on the co-op revenue requirements. The results were identical across all four regulatory models. A 1 percentage-point decrease in the interest rate on the long-term debt will lower projected revenue requirements by $8 million per year, on average.

Figure 27. Sensitivities to change in WACC – Kauai County revenue requirements forecast ($000s, nominal)



4 Appendix A: Scope of work to which this deliverable responds

2.5.1 Estimated annual revenue requirement for each of the remaining regulatory models, including major costs by category; graphics comparing the three regulatory model outcomes. CONTRACTOR shall provide the expected annual revenue requirement for operation under each regulatory model through 2045, including the identification of all major cost elements.

DELIVERABLE FOR TASK 2.5.1. CONTRACTOR shall provide its conclusions and all work related to developing an estimated annual revenue requirement for each of the recommended regulatory models. CONTRACTOR shall develop an estimate of the major costs by category (essentially regulated asset base, operations and maintenance costs, cost of capital, depreciation, and tax). CONTRACTOR shall include a written summary of the findings in MS Word, an MS Excel file, which shall detail the estimated revenue requirements through 2045 under each of the regulatory models and graphics that compare the three regulatory model outcomes. CONTRACTOR shall submit deliverable for TASK 2.5.1 to the STATE for approval.

2.5.3 Analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model. CONTRACTOR shall provide an overview of how costs differ and how the revenue requirement is calculated under each regulatory model.

DELIVERABLE FOR TASK 2.5.3. CONTRACTOR shall provide its conclusions and all work related to an analysis of how costs differ under each regulatory model as well as an explanation of the revenue requirement calculation under each model. CONTRACTOR shall present the analysis conducted in Task 2.5.2. as well as discussion of the major differences in the drivers affecting costs and revenue, and the build-up to the revenue requirement. CONTRACTOR shall include a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.3 to the STATE for approval.

5 Appendix B: List of works consulted

Hawaii Electric Light Company. *Annual Report of the Hawaii Electric Light Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Hawaii Electric Light Company. *Docket No. 2015-0170. Application of Hawaii Electric Light Company for Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits.* September 2016.

Hawaii State Energy Office. *Utility Resources.* Website. <http://energy.hawaii.gov/developer-investor/utility-resources>. Access Date: February 14, 2018.

Hawaiian Electric Companies. *PSIP Update Report – Book 1.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 2.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 3.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 4.* December 2016.

Hawaiian Electric Company. *Annual Report of the Hawaiian Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Hawaiian Electric Company. *Docket No. 2016-0328. Application of Hawaiian Electric Company for Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits. HECO-3203.* December 2016.

Kahn, Alfred, *The Economics of Regulation: Principles and Institutions,* Cambridge, MA: MIT Press, 1988.

Kauai Island Utility Cooperative. *2012 Annual Report to the PUC.* March 2013.

Kauai Island Utility Cooperative. *2013 Annual Report to the PUC.* March 2014.

Kauai Island Utility Cooperative. *2014 Annual Report to the PUC.* March 2015.

Kauai Island Utility Cooperative. *2015 Annual Report to the PUC.* March 2016.

Kauai Island Utility Cooperative. *2016 Annual Report to the PUC.* March 2017.

Kauai Island Utility Cooperative. *2016 Annual Report.*

Kauai Island Utility Cooperative. *2017 Capital Improvements Program for Ensuing Five Years.* December 2016.

Kauiai Island Utility Coopeative. *Consolidated Financial Statements – December 31, 2016 and 2015.* April 2017.

Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009.

Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters.* June 2009.

Maui Electric Company. *Annual Report of the Maui Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Maui Electric Company. *Docket No. 2017-0150. Application of Maui Electric Company for Approval of Rate Increases and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits.* October 2017.

National Association of Regulatory Utility Commissioners. Regulatory Authority Competences in Monitoring the Bookkeeping of the Regulated Companies. May 17, 2013.

National Association of Regulatory Utility Commissioners. Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.

"Rural Economic Development Loan and Grant Programs, RD Instruction 4280-A." *USDA Rural Development.* Web. <https://www.rd.usda.gov/files/4280a.pdf>

State of Hawaii Department of Business, Economic Development, and Tourism. Research and Economic Analysis. *2016 The State of Hawaii Data Book: A Statistical Abstract.* November 2017.

State of Hawaii Public Utilities Commission. *Docket No. 2009-0050. Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules,*

United States Department of Agriculture. *What are Patronage Refunds? Agricultural Cooperative Service, Cooperative Information Report Number 9*. January 1985.

Wahlen, James, Jefferson Jones and Donald Pagach. "Intermediate Accounting: Reporting and Analysis." South-Western Cengage Learning.

Williams, Kevin T. "The Business Case for Co-Op Acquisitions." *Public Utilities Fortnightly – Fortnightly Magazine*, January 2005. Web. <https://www.fortnightly.com/fortnightly/2005/01/business-case-co-op-acquisitions>

Assessment of projected average retail rates under each regulatory model

prepared for the Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

December 28, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 2.5.2, is one of several working papers issued as part of this engagement. It provides a matrix comparing the projected system average retail rates under each regulatory model through 2045 for an average residential, commercial, and industrial customer. In general, the estimated rates follow the pattern of growth in overall revenue requirement for each utility and regulatory model; however, the rates do not increase as fast as the revenue requirement considering the moderate growth in load. Put differently, the increased revenue requirement is also spread over a larger number of customers throughout the forecast period. In summary, the alternative regulatory models are expected to provide lower average electricity rates with respect to the status quo across all the customer classes in all the counties, except for Lanai.

Table of contents

Table of figures

List of acronyms

AED	Average-Excess Demand
DBEDT	Hawaii Department of Business Economic Development and Tourism
DSPP	Distributed System Platform Provider
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electric Reliability Administrator
IGO	Independent Grid Operator
LEI	London Economics International LLC
MECO	Maui Electric Company
NARUC	National Association of Regulatory Utility Commissioners
NCD	Non-Coincident Demand
PBR	Performance-Based Regulation
PR	Peak Responsibility
PUC	Public Utilities Commission
TOU	Time-of-Use

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.5.2 in the project scope of work, compares the estimated system average retail rates under each regulatory model through 2045 for an average residential, commercial, and industrial customer. Furthermore, this memo illustrates the projected average consumption level for the different customer classes and demonstrates how the average system rate and the aggregate bill may change through 2045 for each regulatory model.

1.1 Rate structure for utilities in the State of Hawaii

In the State of Hawaii, as is typical of the electricity industry, electricity rates vary among different customer classes. Hawaiian Electric Company, Inc. ("HECO"), Hawaiian Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO"), collectively known as the "HECO Companies" in this memo, as well as the Kauai Island Utility Cooperative ("KIUC") have similar ratemaking procedures, including functionalization, classification, and allocation of costs necessary to render service, which then inform how rates are calculated for each customer class from the overall revenue requirement. Customer classes include residential, commercial (or general service), large power service, and other (street lighting, electric vehicles, etc.), and each class may include sub-classes. This memo focuses on the residential, commercial, and large power customer classes.

1.2 Rate estimates for all utilities and regulatory models per customer class

In order to estimate electricity rates under the various regulatory models through to 2045, the Project Team relied on the load forecast for each county (or for each island for Maui County) in the State (Task 1.5.2) as well as the revenue requirement forecast for each county (or island) under the different regulatory models (Task 2.5.1). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, in order to estimate future rates for typical residential, commercial, and large power users.

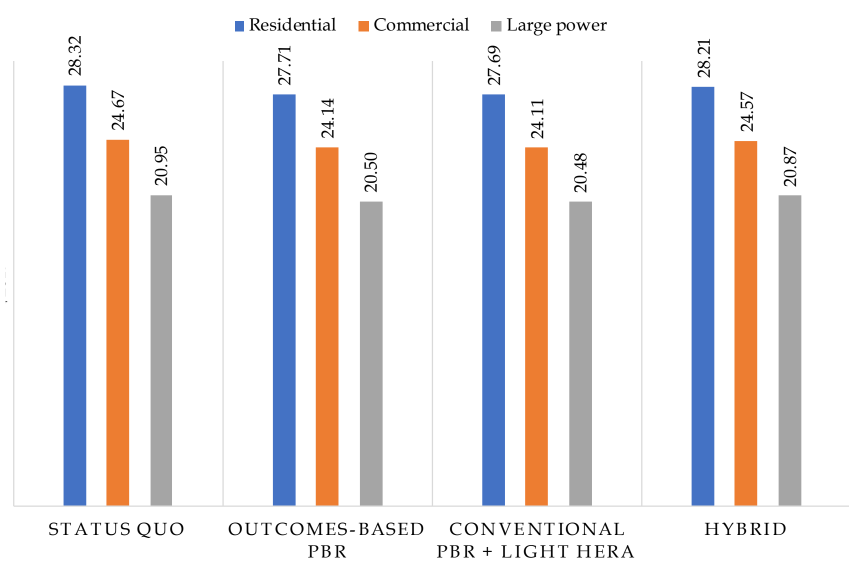
The Project Team notes that the rates mimic primarily the growth pattern of overall revenue requirements for each utility and regulatory model, but do not grow as fast as revenue requirement considering the moderate growth in load. The Project Team also notes that the differences in rates between regulatory models are predominantly driven by their differences in revenue requirements (as discussed in Task 2.5.1), as load forecasts do not vary between the models.

Furthermore, the average rates presented in this section correspond to the average over the forecast horizon of annual rates, converted from nominal dollars into constant 2017 dollars.

1.2.1 HECO projected average rates

Over the forecast horizon, average rates for HECO residential customers in Honolulu County are anticipated to range from 27.7 cents/kWh under the Outcomes-based performance-based regulation ("PBR") and Conventional PBR with Light Hawaii Electricity Reliability Administrator ("HERA") models, to 28.2 and 28.3 cents/kWh respectively for the Hybrid[1] and status quo models. In addition, the average rates across all the classes are expected to be lower under the alternative regulatory models than the status quo. Commercial and large power rates are similarly impacted, with the Outcomes-based PBR and Conventional PBR with Light HERA models showing lower than average rates relative to the other models, and the status quo resulting in the highest rates. These results are illustrated in Figure 1.

Figure 1. Projected average rates over forecast horizon in Honolulu County for each regulatory model (2017 cents/kWh)

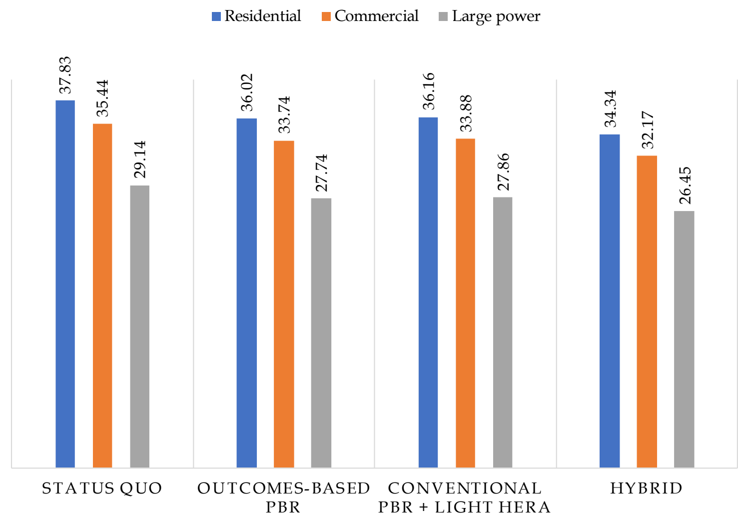


1.2.2 HELCO projected average rates

For Hawaii County residential customers, the HELCO average rates over the forecast horizon are projected to be lower under the three alternative regulatory models than the status quo. The average rates are anticipated to be approximately equivalent under the Outcomes-based PBR and Conventional PBR with Light HERA models at around 36.0 and 36.2 cents/kWh, respectively. The average rates are expected to be lowest under the Hybrid model and highest under the status quo, or approximately 34.3 cents/kWh and 37.8 cents/kWh, respectively. Commercial and large power rates are similarly impacted; these results are illustrated in Figure 2.

[1] As discussed in previous working papers, the Hybrid model comprises of the Outcomes-based PBR, distribution system platform provider ("DSPP") and Independent Grid Operator ("IGO").

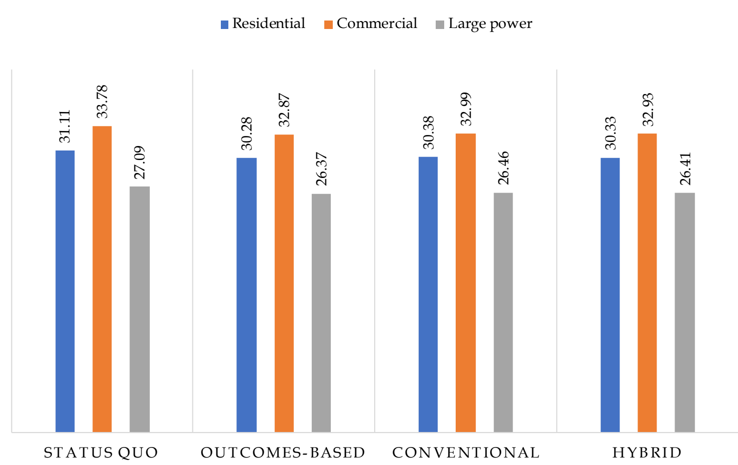
Figure 2. Projected average rates over forecast horizon in Hawaii County for each regulatory model (2017 cents/kWh)



1.2.3 MECO projected average rates

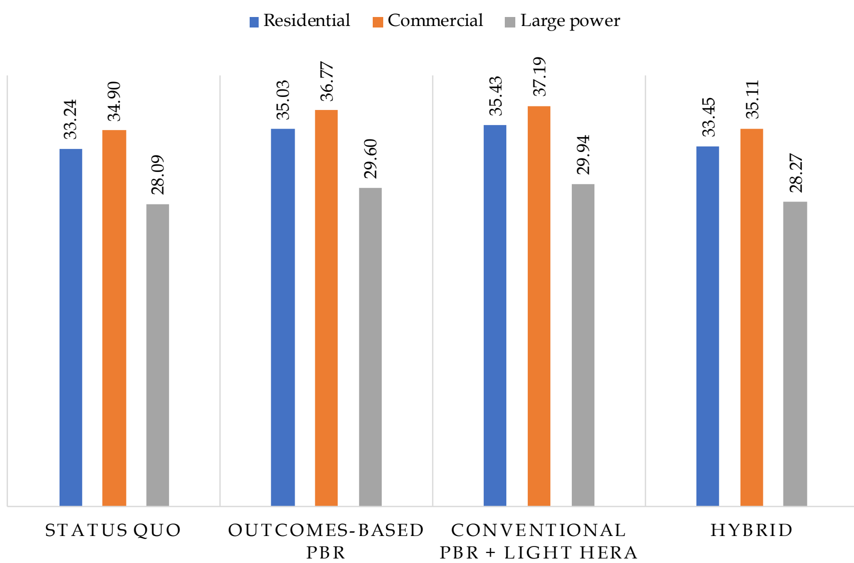
For Maui County residential customers on the island of Maui, the three alternative regulatory models are expected to provide lower average rates than the status quo. More specifically, the MECO average rates over the forecast horizon are anticipated to be similar under the Outcomes-based PBR and Hybrid models at around 30.3 cents/kWh. The average residential rates are expected to be slightly higher under the Conventional PBR with Light HERA model at approximately 30.4 cents/kWh, followed by the status quo at approximately 31.1 cents/kWh. Commercial and large power rates are similarly impacted, with results shown in Figure 3.

Figure 3. Projected average rates over forecast horizon on the island of Maui for each regulatory model (2017 cents/kWh)



On the island of Lanai, projected average rates over the forecast horizon are slightly higher than on the island of Maui. The three alternative regulatory models are expected to have higher average rates than the status quo across all the classes. The highest projected average rates over the forecast horizon are found under the Conventional PBR with Light HERA model at around 35.4 cents/kWh, followed by the Outcomes-based PBR model at around 35.0 cents/kWh, the Hybrid model at about 33.4 cents/kWh, and lastly, the lowest projected average rates under the status quo at approximately 33.2 cents/kWh. Commercial and large power customers are similarly impacted. Results are depicted in Figure 4.

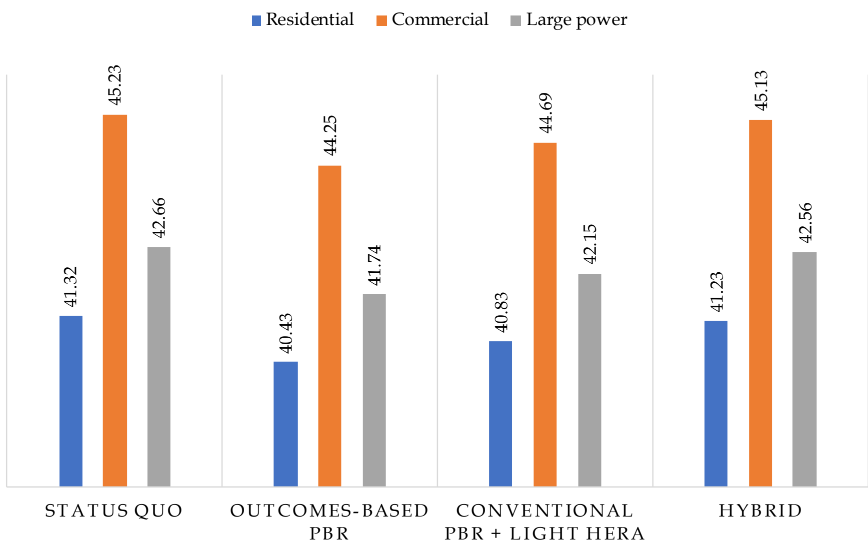
Figure 4. Projected average rates over forecast horizon on the island of Lanai for each regulatory model (2017 cents/kWh)



On the island of Molokai, projected average rates over the forecast horizon for MECO customers are the highest among the three Maui County islands. Historically, both Molokai and Lanai have featured higher rates than Maui. The three alternative models are expected to provide lower average rates than the status quo, with the Outcomes-based PBR resulting in the lowest average rates among the different classes of customers. Residential rates are anticipated to average approximately 41.3 cents/kWh and 41.2 cents/kWh under the status quo and Hybrid models, respectively. Projected average rates over the forecast horizon are slightly lower under the Conventional PBR with Light HERA and Outcomes-based PBR models at approximately 40.8 cents/kWh and 40.4 cents/kWh, respectively. While higher than both residential and large power rates, commercial rates are similarly impacted; commercial rates range from 44.2 cents/kWh to 45.2 cents/kWh. Large power rates, too, mimic the trends of residential and commercial rates, ranging from 41.7 cents/kWh to 42.7 cents/kWh. These rates are reflected in Figure 5.

contact:
Gabriel Roumy/Shrutika Sainani
+1 (617) 933-7225
gabriel@londoneconomics.com

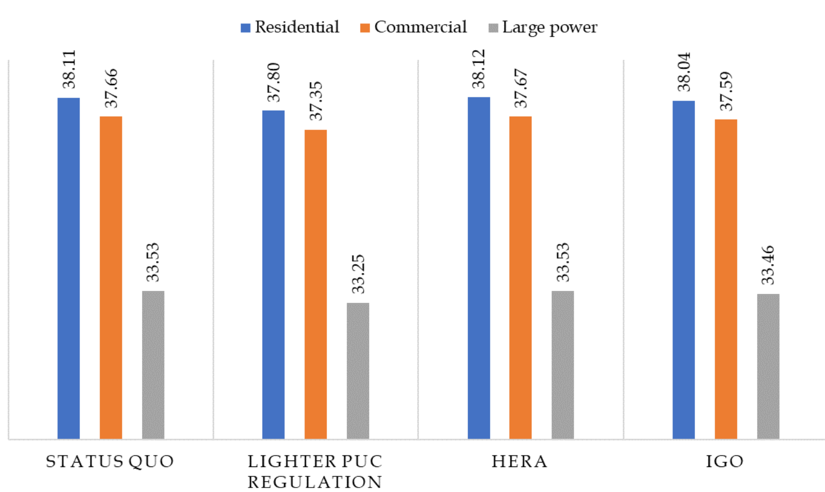
Figure 5. Projected average rates over forecast horizon on the island of Molokai for each regulatory model (2017 cents/kWh)



1.2.4 KIUC projected average rates

Lastly, for Kauai County, average rates over the forecast horizon for KIUC residential customers are anticipated to be slightly lower than the status quo at approximately 37.8 cents/kWh and 38.0 cents/kWh under the Lighter PUC regulation and IGO models, respectively. The HERA model has almost the same projected average rate as the status quo (around 38.1 cents/kWh). Commercial and large power rates are similarly impacted, with the lowest expected average rates found under the Lighter PUC regulation model, and higher rates under the other three regulatory models. These results are depicted in Figure 6.

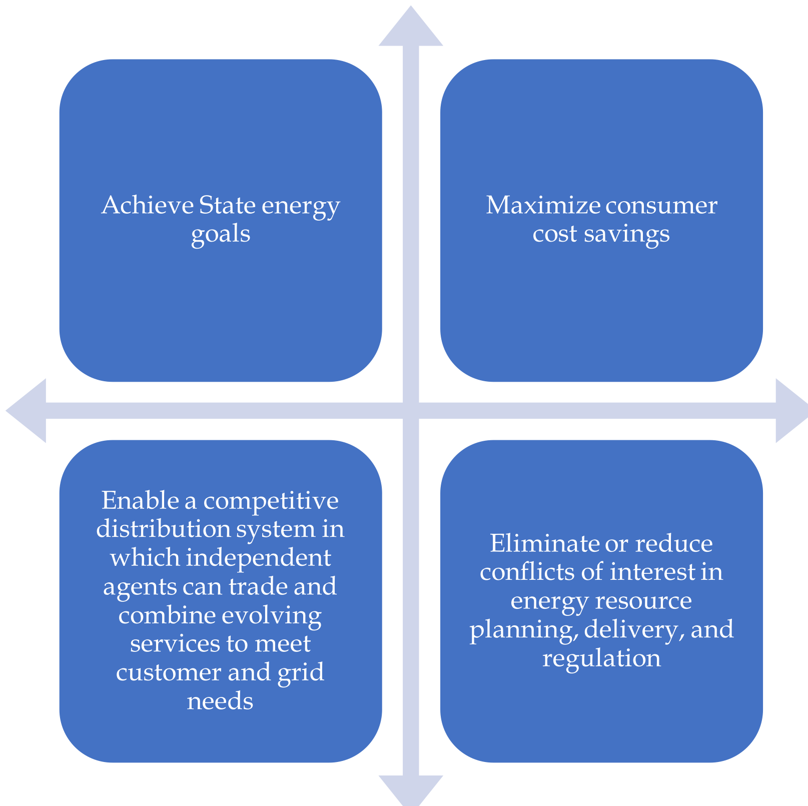
Figure 6. Projected average rates over forecast horizon in Kauai County for each regulatory model (2017 cents/kWh)



2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the State legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[2] was contracted to perform this study.[3]

Figure 7. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to evaluate the different utility ownership and regulatory models for the State of Hawaii and the ability of each model to achieve the State's key criteria[4] listed in Figure 7. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the State. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms

---

[2] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[3] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[4] House Bill No. 1700 Relating to the State Budget.

of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[5]

This deliverable corresponds to Task 2.5.2 in the project scope of work. It includes forecasted system average retail rates through 2045 using the revenue requirement from Task 2.5.1 (Estimated annual revenue requirement for each of the selected regulatory models). For the HECO Companies, the three alternative regulatory models to the status quo are comprised of the Outcomes-based PBR, Conventional PBR with Light HERA, and Hybrid (i.e., Outcomes-based PBR with DSPP and IGO) models. For KIUC, on the other hand, the three alternative regulatory models to the status quo are comprised of the Lighter Public Utilities Commission ("PUC") regulation, HERA, and IGO models. This document also includes a matrix comparing the projected system average retail rates under each regulatory model for an average residential, commercial, and industrial customer. Overall, this memo illustrates the average consumption level for the different customer classes and shows how average system rates and the aggregate bill may change through 2045 for each regulatory model.

[5] Hawaii Contract No. 65595. Scope of Services.

3 Current electricity rates in the State of Hawaii

As is common in the electricity industry, electricity rates vary by customer classes in the State of Hawaii. In this regard, both the HECO Companies and KIUC employ similar ratemaking procedures to inform how rates are calculated for each applicable rate schedule. The rate structure, the HECO Companies' and KIUC's calculation methodologies, and the role of the Hawaii PUC in ratemaking are discussed in detail in Task 1.6.4 (Comparison of projected average retail rates under each ownership model) and summarized in the sections below.

3.1 Rate structure

HELCO and MECO both have five rate classes, namely "R" Residential, "G" Small Power Use Business, "J" Medium Power Use Business, "P" Large Power Use Business, and "F" Street Lighting. HECO, in addition to the five rate classes, has an additional rate class called "DS" Large Power Directly Served Services. Descriptions of the applicability of each rate class under the HECO Companies have been provided in Task 1.6.4.

Similarly, KIUC has eight rate classes, namely Schedule "D" Residential, Schedule "G" Small Commercial, Schedule "J" Large Commercial, Schedule "L" Large Power (Primary), Schedule "P" Large Power (Secondary), Schedule "NEM PILOT", Schedule "Q" Modified – Cogenerators, and Schedule "SL" Street Lighting. Of these, Schedule "NEM PILOT" and Schedule "Q" are energy credit payment rates to customers ($ per kWh). The thresholds KIUC uses to separate commercial rate classes are different from those of the HECO Companies and are described in detail in Task 1.6.4.

The HECO Companies' and KIUC's average rates for each rate class in 2017 are shown in Figure 8 and Figure 9. Cost components (e.g., energy consumption, customer charge, Green Infrastructure Fee, demand charges, etc.) within the current rates are discussed in Task 1.6.4.

Figure 8. HECO Companies: average price of electricity (2017 average cents/kWh)

Rate Schedule	HECO	HELCO	MECO			Average
			Maui	Molokai	Lanai	
"R" Residential	28.22	34.2	30.64	35.57	35.87	32.90
"G" Small Power Use Business	29.33	39.24	34.12	42.70	40.98	37.27
"J" Medium Power Use Business	24.31	30.39	29.35	34.52	38.60	31.43
"P" Large Power Use Business	22.18	26.76	26.83	27.23	34.02	27.40
"DS" Large Power Use Business, Directly Served	20.73					20.73
"F" Street and Park Lighting	25.26	33.41	27.57	33.07	35.05	30.87

Note: These numbers are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: HECO Companies. Rates and Regulations – Average price of electricity. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/average-price-of-electricity>. Access Date: October 12, 2018.

Figure 9. KIUC: average price of electricity (2017 average cents/kWh)

Rate Schedule	KIUC
Residential	34.52
Commercial	34.19
Large Power	30.70
Street Lighting	80.59
Irrigation	15.98

Note: These figures are derived by dividing the total revenue by the total kWh sold for each category during the year.
Source: KIUC. "KIUC Miscellaneous Data 2013-2017." Annual Report to the PUC (December 31, 2017). PDF page 47.

3.2 The HECO Companies' and KIUC's rate calculation methodologies

The PUC is responsible for determining total annual revenues required by the HECO Companies to cover both expenses and the opportunity to earn a fair return on its investments. Each of the determined cost components of the revenue requirement are then allocated amongst customer classes as a function of cost to provide services to said customer classes.

To determine the costs borne by the different rate classes, the HECO Companies utilize a cost of service study tool. Specifically, the HECO Companies rely on an embedded cost of service study (as opposed to a marginal cost study). The embedded cost of service study methodology is comprised of three major steps: functionalization of costs into generation, transmission, and distribution functions; classification of functionalized costs into energy-related, demand-related, and customer-related costs; and the allocation of cost components to the different rate classes. KIUC also uses a similar embedded cost approach for the cost of service analysis (including functionalization, classification, and allocation). Further details on each of these steps taken by the HECO Companies and KIUC are provided in Task 1.6.4.

3.3 Role of PUC in ratemaking

All rates, schedules, rules, and practices made or changed by public utilities are subsequently filed with the PUC. According to the Hawaii Revised Statutes ("HRS") Chapter 269-16, the PUC is required to issue its decision within nine months from the date the application is filed by the utility.[6] The PUC has adopted a cost of service mechanism, a decoupling mechanism, and earnings sharing mechanism as part of the regulatory framework explained further in Task 2.1.1 (Review of potential regulatory models that could be applied in Hawaii State) and Task 3 (Additional Analyses). The rate design methodology described above has also been approved by the PUC in recent rate cases for KIUC (Docket 2009-0050), HECO (Docket 2016-0328), and HELCO (Docket 2015-0170).[7]

[6] HRS 269-16.

[7] Interim rate order approved for HELCO. Revised one step interim rate increase authorized, effective 2/16/18 for HECO.

4 Forecast of electricity rates under various regulatory models

In order to calculate the electricity rates under the various regulatory models through to 2045, the Project Team relied on the load forecast for the various counties and islands (Task 1.5.2), as well as the revenue requirement forecast for each county and island under the different regulatory models (Task 2.5.1). Furthermore, the Project Team used the historical cost allocation factors, reflected in historical average rates for each utility and customer class, to estimate future rates for typical residential, commercial, and large power users.

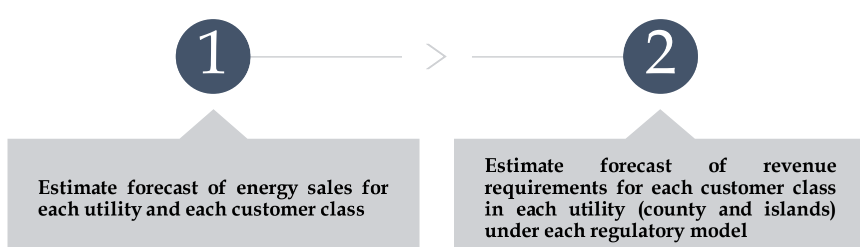
4.1 Methodology to estimate future rates

The methodology employed to determine future rates is similar to the methodology used in Task 1.6.4. The Project Team first used historical 2016[8] data from the utilities' annual reports to the PUC to calculate the ratios of electricity sales, electricity revenues, and number of customers per customer class for each of the utilities in the State of Hawaii, as illustrated in Figure 11.

- The electricity sales ratio represents the share of electricity sales (in MWh) for each customer class;
- The electricity revenues ratio represents the share of electricity revenues (in dollars) for each customer class; and
- The average number of customers ratio represents the ratio of customers for each customer class.

As a first step, the Project Team divided the load forecast for each utility into an estimate of energy sales for each class of customer. To do this, the Project Team applied the historical electricity sales ratios per customer class illustrated in Figure 11 to the load forecast for each utility that was created as part of Task 1.5.2. As a second step, the Project team divided the forecast of revenue requirements for each county and island, as well as for each regulatory model, into revenue requirements for each class of customer. For this task, the Project Team used the electricity revenues ratios illustrated in Figure 11.

Figure 10. Elements of estimated projected rates



[8] In this case the Project Team relied on 2016 data even though 2017 data is available so that the methodology is consistent with, and results comparable to, Task 1.6.4. Nonetheless, 2017 and 2016 ratios are comparable, with differences in energy sales, revenue, and customer ratios ranging from -1.0% to 1.2%.

Figure 11. Historical distribution of electricity sales, electricity revenues, and the average number of customers per customer classes for utilities in the State of Hawaii

Customer class	HECO			HELCO		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	23.7%	28.1%	88.9%	36.2%	39.3%	84.5%
Commercial	32.0%	33.0%	10.6%	39.3%	40.1%	15.1%
Large Power	43.7%	38.3%	0.1%	24.2%	20.3%	0.1%
Other	0.5%	0.6%	0.4%	0.3%	0.3%	0.2%

Customer class	MECO - Maui Island			MECO - Lanai Island		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	32.9%	33.6%	85.5%	25.2%	26.7%	85.6%
Commercial	31.8%	35.2%	14.0%	29.4%	32.7%	14.0%
Large Power	34.8%	30.9%	0.2%	45.0%	40.3%	0.2%
Other	0.5%	0.4%	0.3%	0.4%	0.3%	0.2%

Customer class	MECO - Molokai Island			KIUC		
	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio	Electricity sales ratio	Electricity revenues ratio	Avg. nb. of customers ratio
Residential	35.5%	34.1%	83.2%	37.3%	39.1%	77.2%
Commercial	43.3%	45.5%	16.2%	25.8%	26.7%	12.5%
Large Power	19.2%	19.1%	0.3%	36.3%	33.4%	0.3%
Other	2.0%	1.3%	0.3%	0.6%	0.9%	9.9%

Notes: The electricity sales, electricity revenues, and average number of customers ratios are based on 2016 values for the HECO Companies and KIUC, except for MECO revenue ratios by island due to unavailability of information. Consequently, the electricity revenues ratios for the three islands (i.e., Maui, Lanai, Molokai) were estimated based on 2018 electric revenues by island at present rates. Therefore, it is assumed that 2016 revenue ratios by rate class were approximately equivalent to the revenue ratios by rate class in 2018; Nb = Number.

Source: HECO, HELCO, MECO, and KIUC annual reports to the PUC; MECO 313, 402 Docket No. 2017-0150.

4.2 Forecast of rates

Using the annual revenue requirement per customer class calculated in step one, divided by the annual electricity sales per customer class derived in step two, the Project Team created estimates of average electricity rates per customer class for each utility and each regulatory model. The resulting rates are illustrated in Figure 26 through Figure 29 for HECO, HELCO, MECO, and KIUC.

Of note is that the trend of rates over time follows the growth pattern in overall revenue requirement for each utility and regulatory model, but do not grow as fast as the revenue requirement given the moderate increase in load. The Project Team also notes that the differences in rates among regulatory models are predominantly driven by their differences in revenue requirements (as discussed in Task 1.6.3), as load forecasts do not vary between the models.

Finally, to illustrate the impact of rate changes on the customers, the Project Team calculated average customer charges for each customer class, county, island, and regulatory model by dividing the appropriate revenue requirement by the average number of customers in each class. Of note is that rates under regulatory models employing combinations of two or more regulatory mechanisms (i.e., Conventional PBR with Light HERA and the Hybrid models) are all-inclusive, thereby bundling the costs for the utility, HERA, and IGO, where applicable.

4.2.1 HECO

The alternative regulatory models are expected to result in lower average electricity prices than the status quo across all the customer classes in Honolulu County. Projected average rates over the forecast horizon for HECO residential customers are anticipated to range from 27.7 cents/kWh under the Outcomes-based PBR and Conventional PBR with Light HERA models, to 28.2 and 28.3 cents/kWh under the Hybrid and status quo models, respectively. Commercial and large power rates are similarly impacted, with the Outcomes-based PBR and Conventional PBR with Light HERA models showing lower average rates than the other models. These results are depicted in Figure 12.

The Project Team notes that to calculate the average rates over the forecast horizon, the forecasted rates were converted from nominal dollars into constant 2017 dollars before averaging all values over the forecast horizon.

Figure 12. Projected average rates over forecast horizon in Honolulu County for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	28.3	27.7	27.7	28.2
Commercial	24.7	24.1	24.1	24.6
Large power	21.0	20.5	20.5	20.9

Similarly, Figure 13 illustrates the average impact that the regulatory models would have on monthly customer bills[9] over the forecast horizon while considering the average consumption of each customer class. The table shows that the average monthly bills for the alternative models are projected to be lower than the status quo across all the customer classes. These figures are also shown in constant 2017 dollars.

Figure 13. Projected average monthly bill over forecast horizon in Honolulu County for each regulatory model

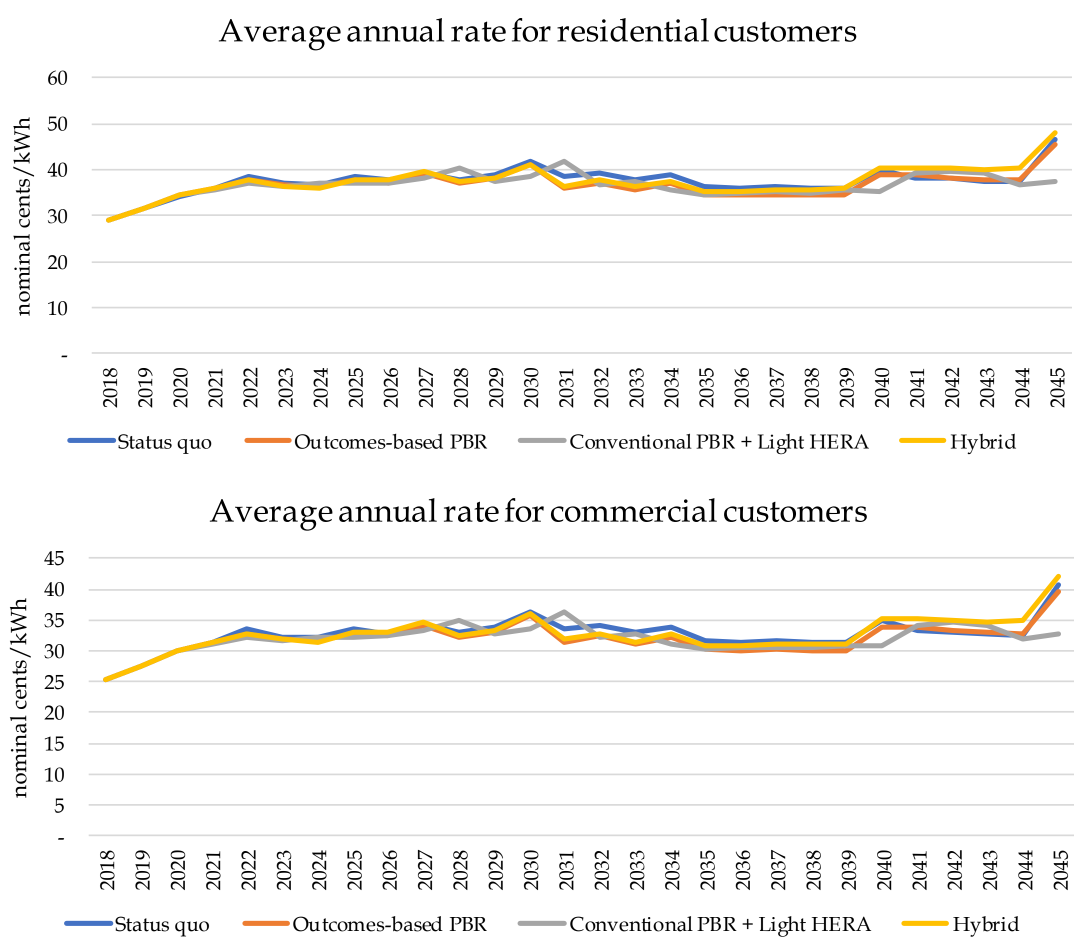
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 121	$ 118	$ 118	$ 120
Commercial	$ 1,188	$ 1,163	$ 1,162	$ 1,183
Large power	$ 102,588	$ 100,465	$ 100,357	$ 102,199

The trends in projected average annual rates under various regulatory models are similar across the customer classes in Honolulu County in that they show a generally increasing trend through 2045. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is 2.0%, 1.8%, 1.1%, and 2.1% for the status quo, Outcomes-based PBR,

[9] Customers bills are comprised of energy charges, based on kilowatt-hours used and the price of electricity, in addition to fixed monthly customer charges and other adjustments. (Source: "Understanding Your Bill." *Hawaiian Electric*. Web. October 17, 2018. < https://www.hawaiianelectric.com/billing-and-payment/understanding-your-bill>

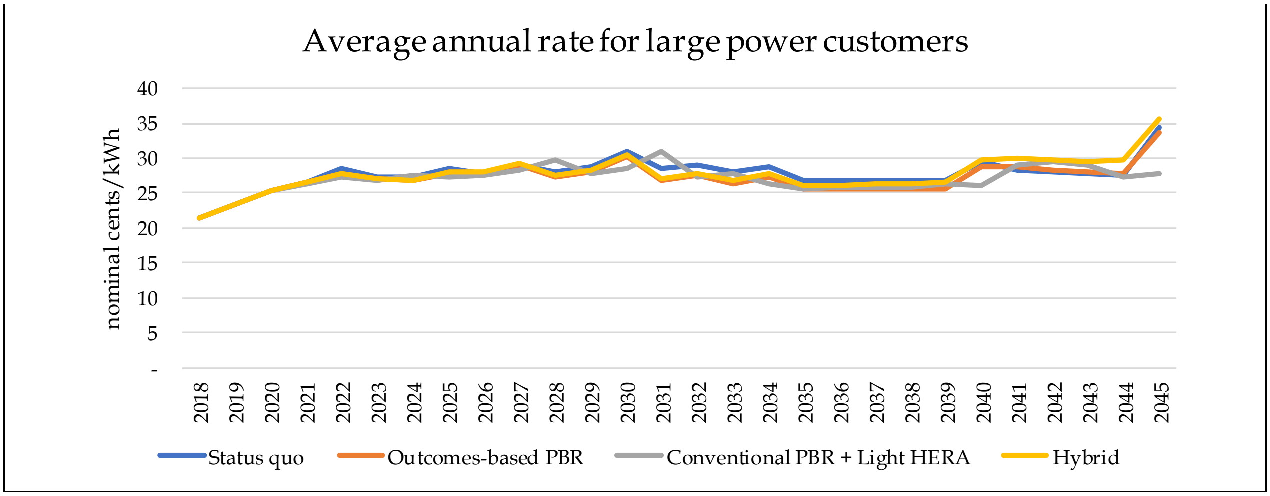
Conventional PBR with Light HERA, and Hybrid models, respectively.[10] Furthermore, the graphs below show that the status quo is projected to feature the highest annual rates for most years across the forecasted horizon for all the customer classes. On the other hand, the Conventional PBR with Light HERA model is anticipated to have the lowest annual rates in most of the years for all the customer classes. The revenue cap mechanism included in this model helps to limit sudden increases in rates following large expenditures. For instance, under most models the rates are projected to increase sharply in 2045 due to the conversion of existing oil-fired generation plants to bio-diesel, whereas the rate increase under the Conventional PBR + Light HERA model is expected to be more gradual because the "I – X" formula[11] limits revenue growth. Figure 14 illustrates the trends in rates for residential, commercial, and large power customers in Honolulu County (values are in nominal dollars).

Figure 14. Projected average annual rates forecast for HECO under various regulatory models



[10] Note that in order to calculate these average growth rates over the forecast horizon, the Project Team calculated the annual growth rates between all years through to 2045, before averaging all values over the forecast horizon.

[11] Revenue growth under the Conventional PBR model is capped using an indexing formula: inflation (I) less productivity factor (X), or commonly referred to as I – X. This is described in more detail in Task 2.1.1.



4.2.2 HELCO

Projected average rates over the forecast horizon for HELCO residential customers are anticipated to be approximately 34.3 cents/kWh under the Hybrid model, 36.0cents/kWh under the Outcomes-based PBR model, 36.2 cents/kWh under the Conventional PBR with Light HERA model, and 37.8 cents/kWh under the status quo. Commercial and large power rates are also similarly impacted, in that the Hybrid model has the lowest projected average rates and the status quo has the highest. These results are illustrated in Figure 15.

Note that to calculate these average rates over the forecast horizon, the Project Team converted the forecasted rates from nominal dollars to constant 2017 dollars before averaging the values over the forecast horizon.

Figure 15. Projected average rates over forecast horizon in Hawaii County for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	37.8	36.0	36.2	34.3
Commercial	35.4	33.7	33.9	32.2
Large power	29.1	27.7	27.9	26.5

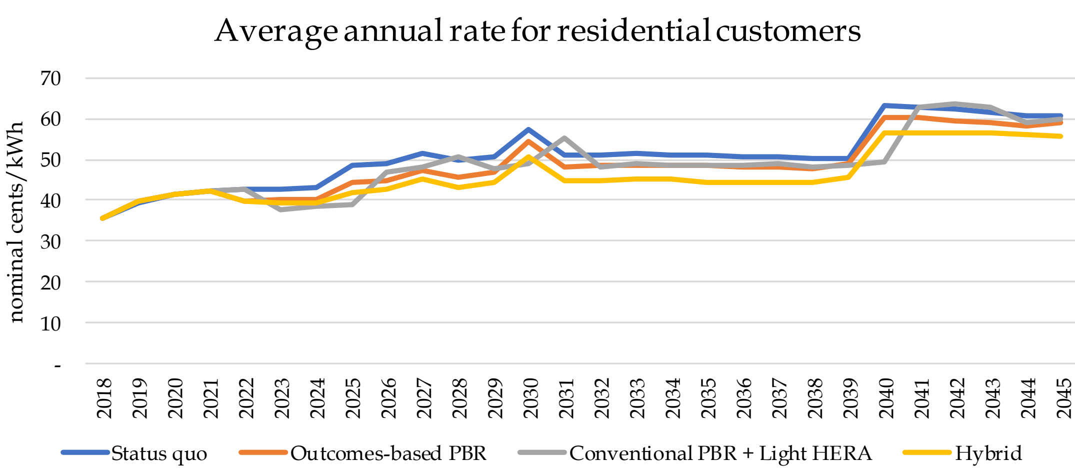
Similarly, Figure 16 illustrates the average impact that the regulatory models would have on the monthly customer bills over the forecast horizon while considering the average consumption of each customer class. For residential, commercial, and large power customers, the alternative regulatory models are anticipated to result in lower monthly bills than the status quo. These figures are also in constant 2017 dollars.

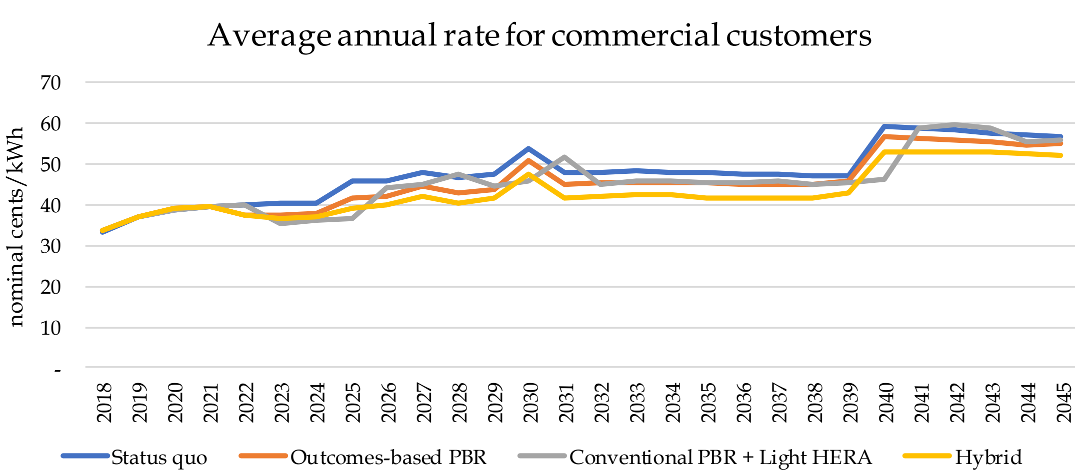
Figure 16. Projected average monthly bill over forecast horizon in Hawaii County for each regulatory model

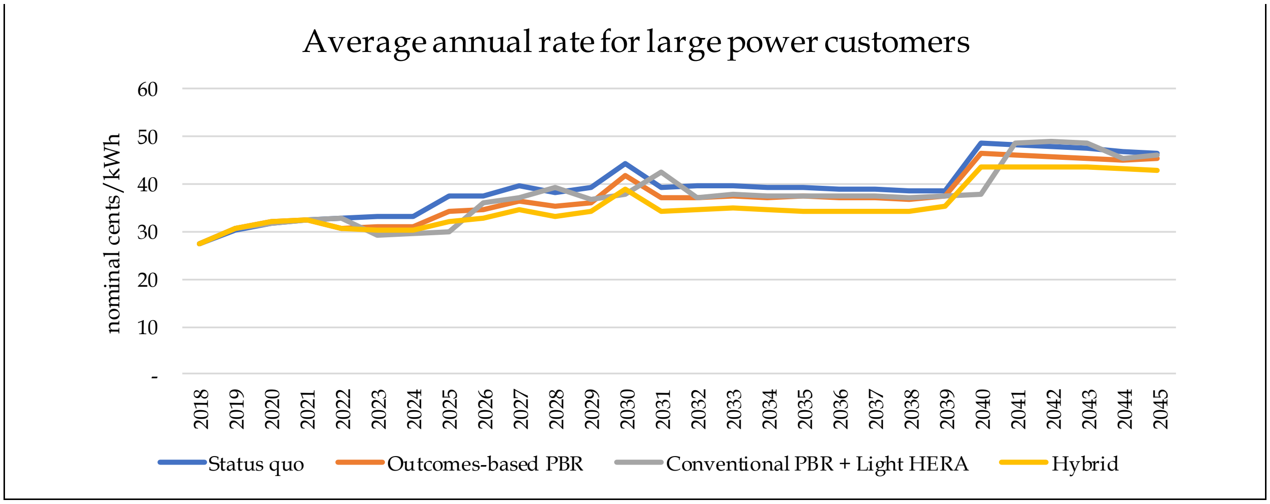
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 139	$ 133	$ 133	$ 127
Commercial	$ 791	$ 753	$ 756	$ 719
Large power	$ 56,406	$ 53,728	$ 53,924	$ 51,315

Furthermore, similar to other counties, the expected rates of the alternative regulatory models are lower on average as compared to the status quo. The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general upwards growth trend throughout the forecast horizon. The average year-over-year growth in forecasted annual rates for all three customer classes from 2018 to 2045 is similar among the regulatory models, ranging between 1.8% and 2.2% with status quo being the highest.. Lastly, the graphs below show that the status quo is projected to have the highest annual rates in most of the years across the forecasted horizon for all the customer classes. On the other hand, the Hybrid model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure 17 illustrates the forecasted annual rates for residential, commercial, and large power customers in Hawaii County (values are in nominal dollars).

Figure 17. Projected average annual rates forecast for HELCO under various regulatory models







4.2.3 MECO

4.2.3.1 Maui

Over the forecast horizon, projected average rates for the alternative regulatory models are lower than the status quo on Maui island. MECO residential customers' average rates on the island are anticipated to be around 30.3 cents/kWh under the Outcomes-based PBR and Hybrid models, and respectively 30.4 cents/kWh and 31.1 cents/kWh under the Conventional PBR with Light HERA model and the status quo. Commercial and large power rates feature a similar trend where the Outcomes-based and Hybrid models have the lowest projected average rates through to 2045, the Conventional PBR with Light HERA model results in a slightly higher average rate, and the status quo results in the highest average rate. These results are shown in Figure 18.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars to 2017 dollars before averaging values over the forecast horizon.

Figure 18. Projected average rates over forecast horizon on the island of Maui for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	31.1	30.3	30.4	30.3
Commercial	33.8	32.9	33.0	32.9
Large power	27.1	26.4	26.5	26.4

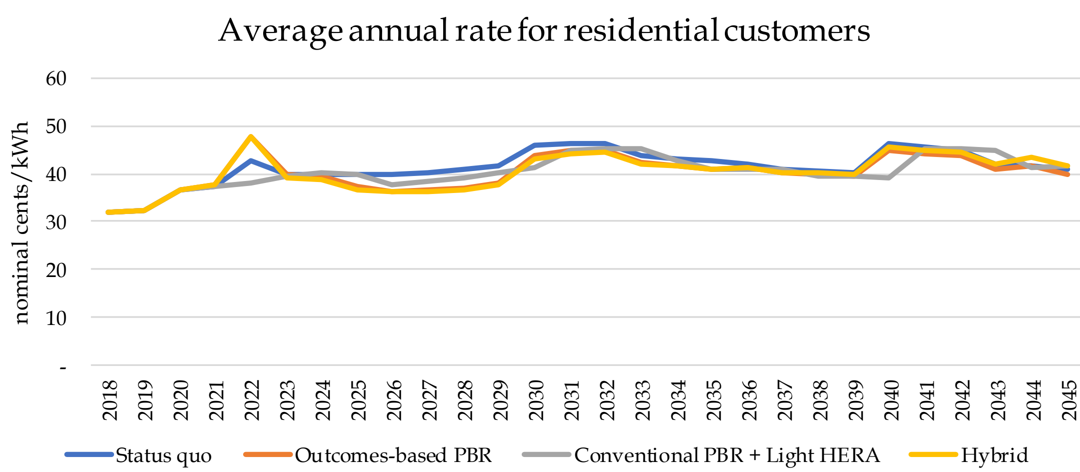
Figure 19 illustrates the average impact that the regulatory models would have on the monthly customer bills through to 2045 while considering the average consumption within each customer class. These figures are also presented in constant 2017 dollars.

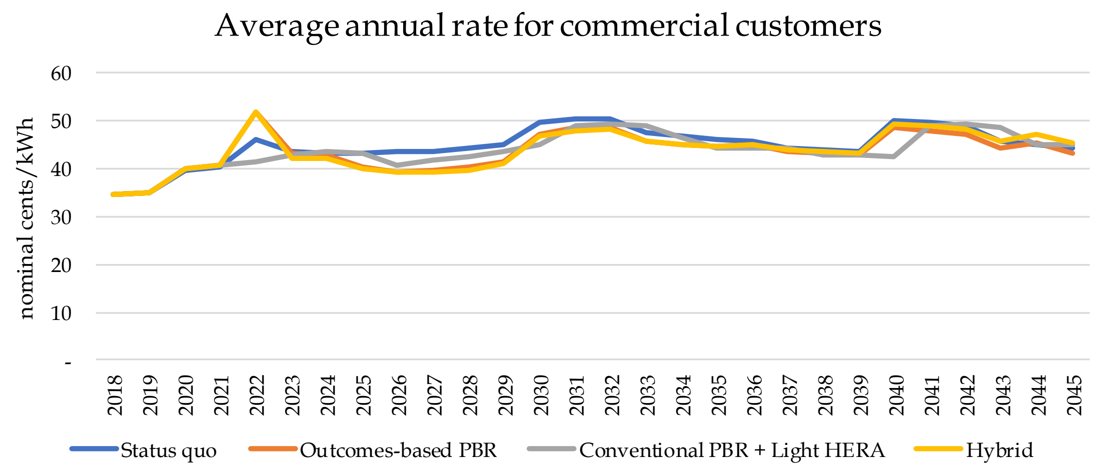
Figure 19. Projected average monthly bill over forecast horizon on the island of Maui for each regulatory model				

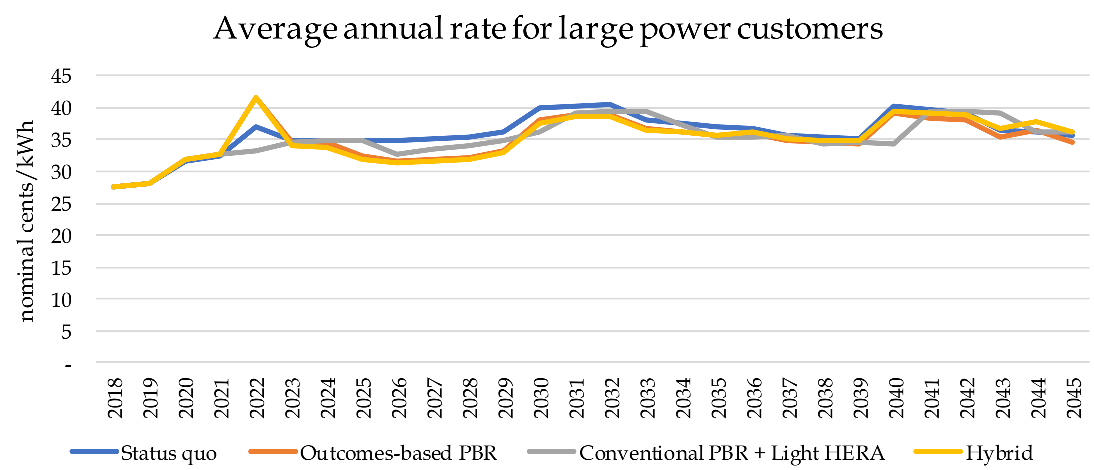
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 158	$ 154	$ 154	$ 154
Commercial	$ 1,012	$ 985	$ 988	$ 987
Large power	$ 59,246	$ 57,679	$ 57,872	$ 57,796

The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general increasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is similar across all the regulatory models, ranging from 1.1% to 1.3% with the Hybrid model featuring the highest growth. Furthermore, the graphs below show that the status quo is projected to have the highest annual rates in most of the years across the forecast horizon for all the customer classes, while the Outcomes-based PBR model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure ***20*** illustrates the trend in rates for residential, commercial, and large power customers on the island of Maui (values shown are in nominal dollars).

Figure 20. Projected average annual rates forecast for the island of Maui under various regulatory models







4.2.3.2 Lanai

Over the forecast horizon, projected average rates for MECO residential customers on the island of Lanai are anticipated to be around 33.2 cents/kWh under the status quo, slightly higher at 33.4 cents/kWh under the Hybrid model, approximately 35.0 cents/kWh under the Outcomes-based PBR model, and the highest at 35.4 cents/kWh under the Conventional PBR with Light HERA model. Projected average commercial rates are slightly higher than the expected average residential rates. Large power rates also mimic the trends exhibited within residential and commercial rates in that they are lowest under the status quo and highest under the Conventional PBR with Light HERA model. These results are illustrated in Figure 21.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars to 2017 dollars prior to averaging values over the forecast horizon.

Figure 21. Projected average rates over forecast horizon on the island of Lanai for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	33.2	35.0	35.4	33.4
Commercial	34.9	36.8	37.2	35.1
Large power	28.1	29.6	29.9	28.3

Figure 22 illustrates the average impact that the regulatory models would have on monthly customer bills throughout the forecast horizon while considering the average consumption within each customer class. The three alternative regulatory models are projected to have higher average monthly bills than the status quo. These figures are also in constant 2017 dollars.

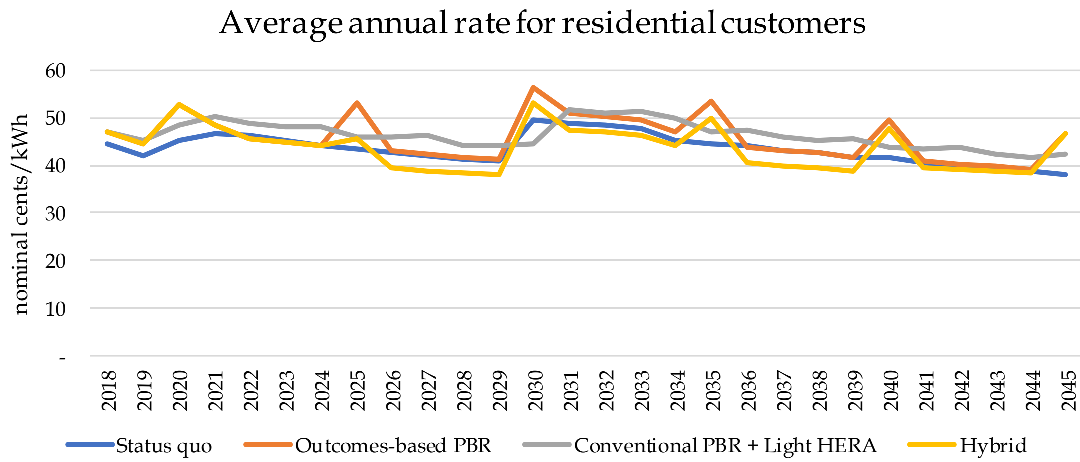
Figure 22. Projected average monthly bill over forecast horizon on the island of Lanai for each regulatory model

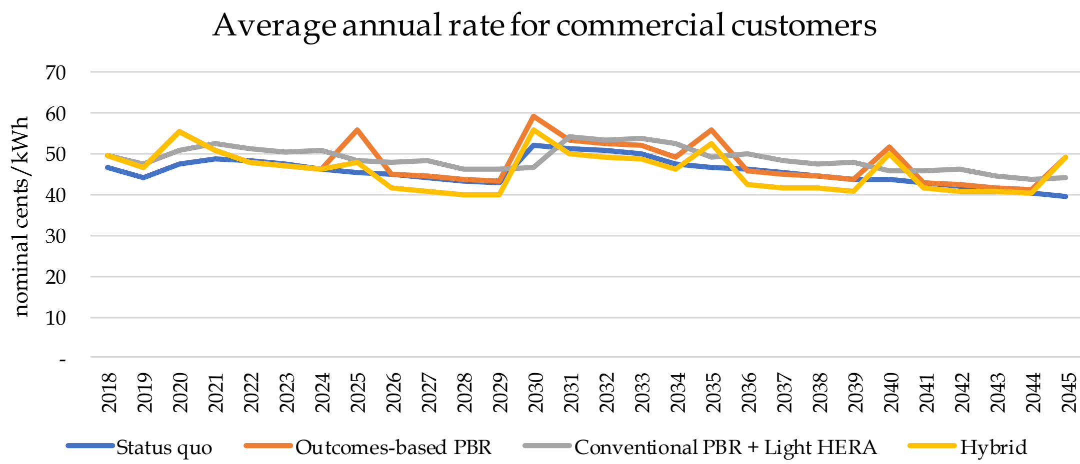
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 129	$ 136	$ 138	$ 130
Commercial	$ 963	$ 1,015	$ 1,026	$ 969
Large power	$ 96,276	$ 101,462	$ 102,603	$ 96,872

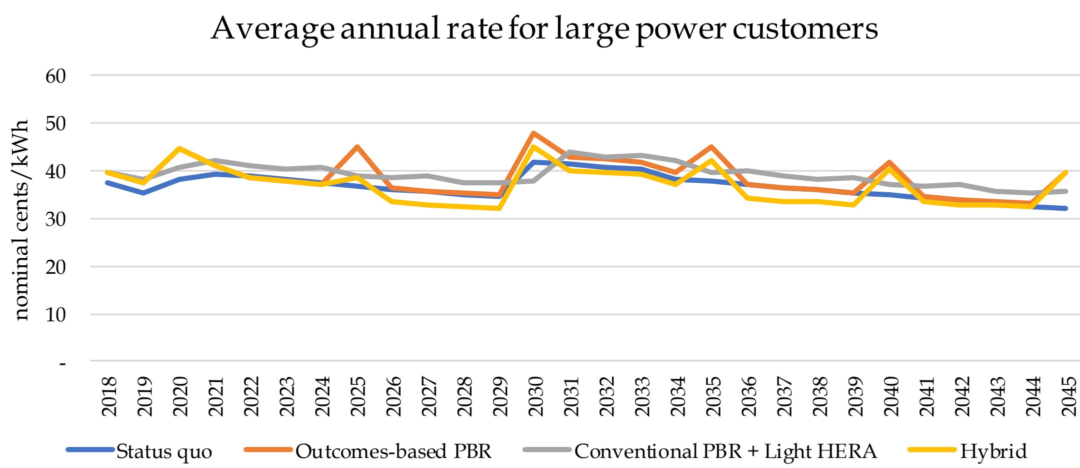
The trends in projected average annual rates under various regulatory models are similar for residential, commercial, and large power customers in that they demonstrate a general decreasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 are respectively 0.5%, 0.7%, -0.3%, and 0.7% under the status quo, Outcomes-based PBR, Conventional PBR with Light HERA, and hybrid models.

Furthermore, the graphs below show that the Conventional PBR with Light HERA is projected to have the highest annual rates in most of the years across the forecast horizon for all the customer classes. On the other hand, the Hybrid model is anticipated to have the lowest annual rates in most of the years for all the customer classes. Figure 23 illustrates the annual rates for residential, commercial, and large power customers on the island of Lanai (values are shown in nominal dollars).

Figure 23. Projected average annual rates forecast for the island of Lanai under various regulatory models







Of note is that, unlike the other two islands in Maui County, the alternative regulatory models would result in higher average rates across all the customer classes on Lanai versus the status quo. This is because of the higher revenue requirements under the three alternative models than under the status quo over the forecast horizon (Task 2.5.1).

Since Lanai and Molokai are smaller markets than Maui, additional PBR costs for the two islands are higher relative to the overall costs of implementing the regulatory models. As per MECO's most recent 2017 rate case, the rate of returns ("RoRs") have been adjusted for the three islands to produce their combined weighted average cost of capital ("WACC"); the RoRs are approximately 8.60% (pre-tax cut, currently around 7.5%), 6.01% and -2.49% for Maui, Lanai, and Molokai, respectively.[12] Additionally, based on historical data, Lanai and Molokai both have low totex capitalization rates (3.63% and 4.38%, respectively) compared to Maui (26.79%).[13] Combined, the smaller market sizes and lower capitalization rates lead to higher revenue requirements under the three alternative regulatory models for Lanai and Molokai. Nonetheless, due to Molokai's negative WACC, its revenue requirements are lower than for Lanai.

4.2.3.3 Molokai

Similar to Maui, the alternative regulatory models are expected to provide lower average rates than the status quo across all the customer classes. Over the forecast horizon, projected average rates for MECO residential customers on the island of Molokai are anticipated to be approximately 40.4 cents/kWh under the Outcomes-based PBR model, 40.8 cents/kWh under the Conventional PBR with Light HERA model, 41.2 cents/kWh under the Hybrid model, and 41.3 cents/kWh under the status quo. Commercial and large power rates, too, mimic the residential rates trend in that the lowest rates are found under the Outcomes-based PBR model, and the highest rates are found under the status quo. These results are shown in Figure 24.

Note that to calculate average rates over the forecast horizon, the Project Team converted the forecasted rates from nominal dollars to 2017 dollars before averaging values over the forecast horizon.

Figure 24. Projected average rates over forecast horizon on the island of Molokai for each regulatory model

2017 cents/kWh	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	41.3	40.4	40.8	41.2
Commercial	45.2	44.3	44.7	45.1
Large power	42.7	41.7	42.2	42.6

Moreover, Figure 25 illustrates the expected average impact that the regulatory models would have on monthly customer bills through to 2045, taking into account the average consumption within each customer class. These figures have been presented in constant 2017 dollars, as well.

12 MECO. *2018 Test Year Rate Case (Docket 2017-0150).*

13 Ibid.

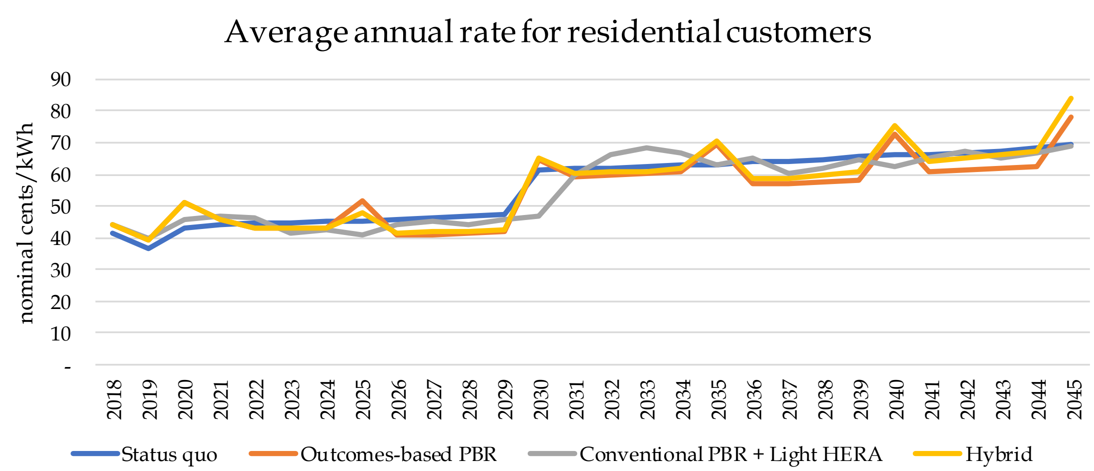
Figure 25. Projected average monthly bill over forecast horizon on the island of Molokai for each regulatory model

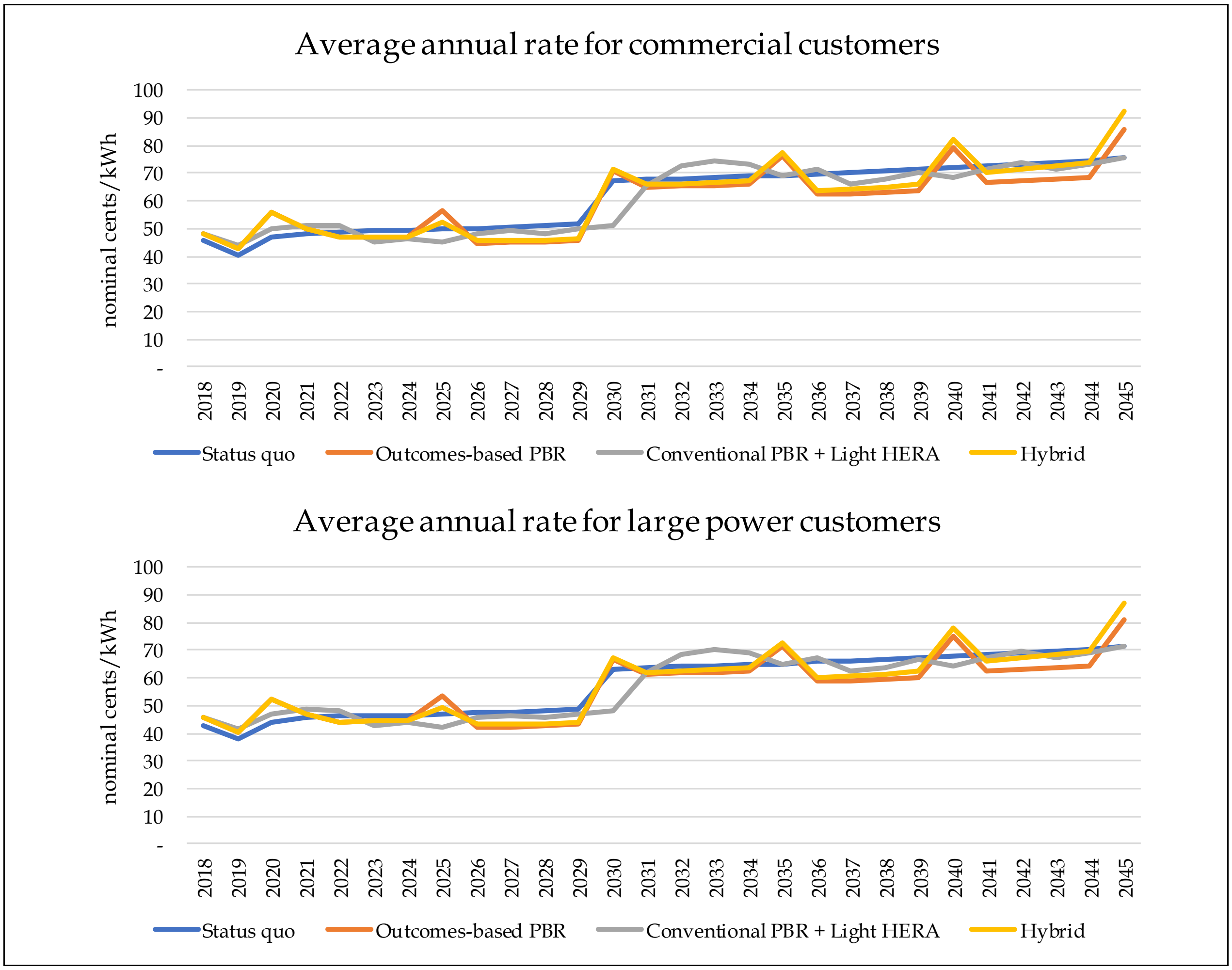
2017 dollars	Status quo	Outcomes-based PBR	Conventional PBR + Light HERA	Hybrid
Residential	$ 94	$ 92	$ 93	$ 94
Commercial	$ 642	$ 630	$ 635	$ 640
Large power	$ 15,579	$ 15,295	$ 15,412	$ 15,547

The trends in projected average annual rates under the various regulatory models are similar for residential, commercial, and large power customers in that they show a general upwards trend through to 2045. Compared to the other islands, the average year-over-year growth in forecasted average annual rates for all three customer types throughout the forecast horizon is more varied. The average growth in rates represents respectively 2.1%, 3.2%, 1.9%, and 3.4% under the status quo, Outcomes-based PBR, Conventional PBR with Light HERA, and Hybrid models.

Furthermore, the graphs below show that the status quo is projected to result in the highest annual rates for most years across the forecasted horizon for all the customer classes. On the other hand, the Outcomes-based PBR model is anticipated to result in the lowest annual rates for most years for all the customer classes. Figure 26 illustrates the residential, commercial, and large power rates on the island of Molokai (values shown in are nominal dollars).

Figure 26. Projected average annual rates forecast for the island of Molokai under various regulatory models





4.2.4 KIUC

On Kauai island, the alternative regulatory models are anticipated to provide slightly lower average rates than the status quo across all the customer classes. Projected average rates for KIUC residential customers over the forecast horizon are expected to be around 37.8 cents/kWh with Lighter PUC regulation, around 38.0 cents/kWh under the IGO model, and about 38.1 cents/kWh under both the status quo and HERA models. Commercial and large power rates are also impacted similarly; the lowest projected average rates are found under the Lighter PUC regulation model. These results are depicted in Figure 27.

Note that to calculate the average rates over the forecast horizon, the Project Team first converted the forecasted rates from nominal dollars into constant 2017 dollars, before averaging values over the forecast horizon.

Figure 27. Projected average rates over forecast horizon in Kauai County for each regulatory model

2017 cents/kWh	Status Quo	Lighter PUC Regulation	HERA	IGO
Residential	38.1	37.8	38.1	38.0
Commercial	37.7	37.4	37.7	37.6
Large power	33.5	33.3	33.5	33.5
Other	54.1	53.6	54.1	54.0

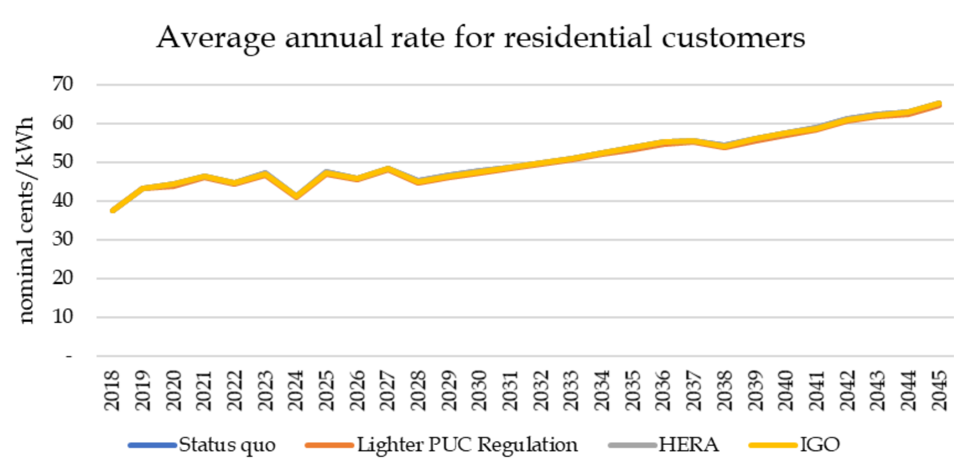
Similarly, Figure 28 illustrates the average impact over the forecast horizon that the regulatory models would have on monthly customer bills considering the average consumption within each custom class. The table shows that monthly bills are lower for Lighter PUC Regulation model and the IGO model across all customer classes while slightly higher for HERA. This is because of the overall higher revenue requirements under the HERA model. These values, too, are presented in constant 2017 dollars.

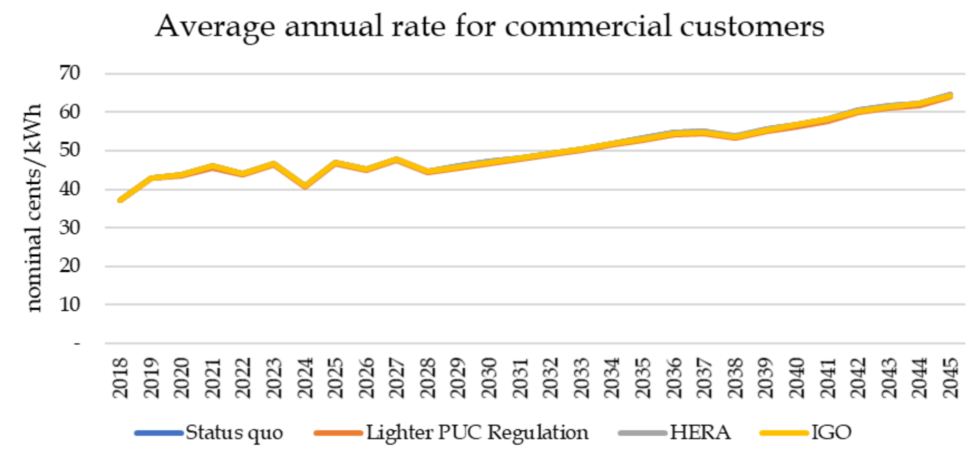
Figure 28. Projected average monthly bill over forecast horizon in Kauai County for each regulatory model

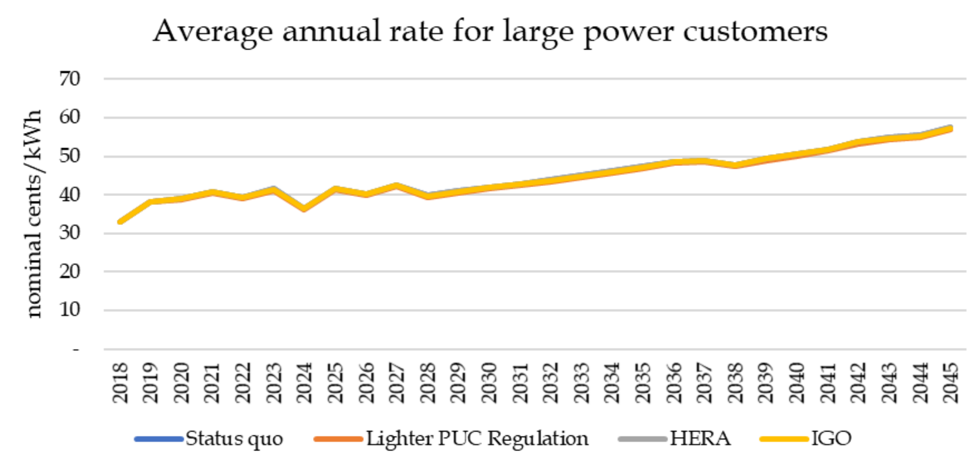
2017 dollars	Status Quo	Lighter PUC Regulation	HERA	IGO
Residential	$ 156	$ 155	$ 156	$ 156
Commercial	$ 659	$ 653	$ 659	$ 657
Large power	$ 31,644	$ 31,386	$ 31,648	$ 31,583
Other	$ 28	$ 28	$ 28	$ 28

Overall, the trends in projected average annual rates under various regulatory models are similar across the three customer classes in Kauai County as they show a general increasing trend throughout the forecast horizon. The average year-over-year growth in forecasted average annual rates for all three customer types from 2018 to 2045 is 2.2% for all status quo and alternative models. Figure 29 illustrates the rates for residential, commercial, and large power customers in Kauai County (values are in nominal dollars).

Figure 29. Projected average annual rates forecast for KIUC under various regulatory models




Average annual rate for commercial customers
nominal cents/kWh
70
60
50
40
30
20
10
-
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Status quo
Lighter PUC Regulation
HERA
IGO


Average annual rate for large power customers
nominal cents/kWh
70
60
50
40
30
20
10
-
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2041
2042
2043
2044
2045
Status quo
Lighter PUC Regulation
HERA
IGO

5 Appendix A: Scope of work to which this deliverable responds

2.5.2. Assessment of system average retail rates for each regulatory model for an average residential, commercial, and industrial customer through 2045. CONTRACTOR shall forecast system average retail rates through 2045 using the revenue requirement from TASK 2.5.1. CONTRACTOR shall provide comparison of forecasted retail rates for each regulatory model.

DELIVERABLE FOR TASK 2.5.2. CONTRACTOR shall include its conclusions and all work to develop system average retail rates for each regulatory model. CONTRACTOR shall use the current rate structure in Hawaii as a baseline and focus on assessing the impact that the regulatory model has on average customer rates. CONTRACTOR shall include conversion of the revenue requirement each year into a fixed and variable rate component that is consistent with Hawaii's current rate, assume an average level of consumption for each category of customer, and calculate how their average system rate or aggregate bill may change through 2045 under each of the recommended regulatory models. CONTRACTOR shall provide a written summary of the findings in MS Word and an MS Excel file with rates under each regulatory model for an average residential, commercial, and industrial customer through 2045. CONTRACTOR shall submit deliverable for TASK 2.5.2 to the STATE for approval.

6 Appendix B: List of works consulted

"Cost of Service Studies." *HECO.* HECO 2017 Test Year: Direct Testimonies and Exhibits Book 10. Page 7-8.

"Energy Rate Adjustment Clause: Rate Data Sheet." *KIUC.* Effective Date: March 1, 2018. Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/rates/2018%20Rate%20Data.pdf>.

Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

HECO Companies. *Rate & Regulations*. Website. <https://www.hawaiianelectric.com/billing-and-payment/rates-and-regulations/hawaiian-electric-rates>. Access Date: March 8, 2018.

HECO. *2017 Test Year Rate Case (Docket 2016-0328).*

HELCO. *2016 Test Year Rate Case (Docket 2015-0170) Book 8.*

MECO. *Annual Report of Maui Electric Company to the Public Utilities Commission State of Hawaii for the year ending December 31, 2016.* < https://puc.hawaii.gov/wp-content/uploads/2014/06/AFR-MECO-2016.pdf>

MECO. *2018 Test Year Rate Case (Docket 2017-0150) Book 2.*

MECO. *2018 Test Year Rate Case (Docket 2017-0150) Book 9.*

MECO. *2017 Test Year Rate Case (Docket 2017-0150) Book 10.*

Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

"Schedule TOU-S". *KIUC.* Website. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/tariffs/tariff1-tou-s.pdf>. Access Date: March 8, 2018.

"Time-of-Use Program." *HECO Companies.* Website. <https://www.hawaiianelectric.com/save-energy-and-money/time-of-use-program>. Access date: March 8, 2018.

Potential risks to utility valuation under each regulatory model

working paper prepared by London Economics International LLC for the State of Hawaii with support from Meister Consultants Group

October 9, 2018

London Economics International LLC ("LEI"), together with Meister Consultants Group, was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals; this document, which responds to Task 2.5.4, is one of several working papers associated with that engagement. It identifies potential risks to utility valuation of the different regulatory models as well as discusses the Project Team's approach to estimating the magnitude of the risks and rationale for certain assumptions. The estimates were based on previous models forecasting revenue requirements.

Table of Contents

Table of Figures

List of acronyms

Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DSPP	Distributed System Platform Provider
ESM	Earnings Sharing Mechanism
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electricity Reliability Administrator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producer
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
O&M	Operations and Maintenance
Opex	Operating expenditures
PBR	Performance-based Regulation
PIM	Performance Incentive Mechanism
PPA	Power Purchase Agreement
PSIP	Power Supply Improvement Plan
PSR	Platform Service Revenue
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
ROE	Return on Equity
RPS	Renewable Portfolio Standards
RUS	Rural Utilities Service
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
Totex	Total expenditures
USDA	United States Department of Agriculture
WACC	Weighted Average Cost of Capital

1 Executive summary

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. The various regulatory models considered were described in previous working papers[1] and included increased oversight from a Hawaii Electricity Reliability Administrator ("HERA"), different variants of Performance-Based Regulation ("PBR"), Independent Grid Operator ("IGO"), Distributed System Platform Provider ("DSPP"), and Lighter regulation of the Kauai Island Utility Cooperative ("KIUC") by the Hawaii Public Utilities Commission ("PUC").

This working paper, which responds to Task 2.5.4 in the project scope of work, provides an estimate of the risks to utility valuations under the recommended regulatory models. It describes the Project Team's approach to estimating the value of the utilities in Hawaii.

Based on previous analyses conducted for Task 2.2.6, the recommended regulatory models analyzed for Honolulu, Hawaii, and Maui Counties were:

- status quo or the current Cost-of-Service ("COS") model for an Investor-Owned Utility ("IOU") (this is the reference case),
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model combining Outcomes-based PBR, IGO, and DSPP.

This report focuses on the three IOUs operating in Hawaii – Hawaiian Electric Company ("HECO") on Honolulu County, Hawaii Electric Light Company ("HELCO") on Hawaii County, and Maui Electric Company ("MECO") on Maui County. The three utilities are jointly referred to as "the HECO Companies" in this report. The Project Team's preliminary analysis for Kauai County indicated that KIUC's valuation was not meaningfully different under the four regulatory models for Kauai County, namely, the status quo (COS under co-op), Lighter PUC Regulation, HERA, and IGO models and therefore, an analysis of the potential risks for KIUC was not performed.

The document summarizes various categories of potential risks that were discussed in more detail in the Task 1.3.1 report. For this analysis, the Project Team focused on three categories of potential risks related to utility valuation, namely:

- financial risk, especially in terms of the risk of a credit rating downgrade,
- business risks in terms of lower electricity sales than forecast, and

[1] Such as Tasks 2.1.1, 2.2.1, and 2.2.6.

- regulatory risks based on a rate freeze during the first three years of PBR implementation and the level of rewards that the utility can earn from meeting performance targets.

The Project Team used the Discounted Cash Flow ("DCF") approach to calculate the utility valuations for each regulatory model. In the base scenario, the Team projected cash flows using the same assumptions in forecasting revenue requirements under Task 2.5.1 and estimated utility valuation by calculating the Net Present Value ("NPV") of those cash flows. The risks described above were then estimated using sensitivity analyses. Each risk was modeled as a change in an input to the DCF calculations; the resulting decrease in NPV (in percentage terms) represented the Team's estimated magnitude of that risk.

It is also important to note that there are other potential risks discussed in this report or Task 1.3.1. Some risks were not analyzed for their impact on utility valuation because they either exist in all regulatory models, or depend on particular aspects of regulatory design, or can be more easily mitigated if they arise. Since this analysis compares risks to utility valuations between the recommended regulatory models, the Project Team focused on the three categories or risks mentioned above.

In summary, the Hybrid model is riskier[2] (in terms of the three risks mentioned above) than the other models because of the uncertainty regarding Platform Service Revenues ("PSRs")[3] and its potentially major impact on utility valuation.[4] If PSRs double every ten years instead of 5, utility valuations could decrease by 2.0% to 6.4%. A rate freeze of three years is also likely to substantially depress valuation by 0.8% to 4.9%. The analysis does offer some evidence that a transition to PBR models could align utility incentives better with those of ratepayers and policymakers: lower than expected electricity sales are a smaller risk to utility valuation than lower levels of performance incentives under PBR (0.1% to 0.2% vs. 0.2% to 1.9%).

Figure 1 below provides the estimated potential decrease in valuation for the assessed regulatory models.

[2] Riskier here means higher potential magnitude of the risk – or a larger potential decline in the NPV of projected cash flows. Additional details on the risks are discussed in Section 4.

[3] Platform service revenues are earning opportunities for utility under a new business model, in which the distribution grid functions as a platform where utilities, customers, and third-party providers can transact energy and services. Utilities can take advantage of their position as the distribution service provider to generate additional revenues from services like bundled products, information sharing with DER providers, or partnering with third parties to finance home energy technologies. (Bade, Gavin. *Little less talk: With new revenue models, New York starts to put REV into action.* Utility Dive, June 2016.)

[4] All utility valuations are as of 2018 and reflect a 27-year horizon (2018-2045).

Figure 1. Potential decrease in valuations by utility, risk category, and regulatory model

($000s)	Conventional PBR + Light HERA	Outcomes-based PBR	Hybrid
Financial Risk			
Credit risk			
HECO	-	-	-
HELCO	-	-	-
MECO	-	0.8%	-
Business Risk			
Lower than expected sales			
HECO	0.1%	0.1%	0.1%
HELCO	0.1%	0.2%	0.2%
MECO	-	-	-
Slower growth of platform revenues			
HECO	N/A	N/A	2.4%
HELCO	N/A	N/A	2.0%
MECO	N/A	N/A	6.4%
Regulatory Risk			
Rate freeze for the first three years			
HECO	2.1%	2.4%	1.9%
HELCO	1.0%	0.8%	0.8%
MECO	3.1%	4.9%	3.7%
Actual rewards = half of maximum available rewards			
HECO	0.9%	0.8%	0.3%
HELCO	0.6%	0.3%	0.2%
MECO	1.2%	1.9%	0.9%

Note – valuation as of 2018 with a 27-year horizon; discount rate of 7.57%, 7.79%, and 7.43% used for HECO, HELCO, and MECO respectively.

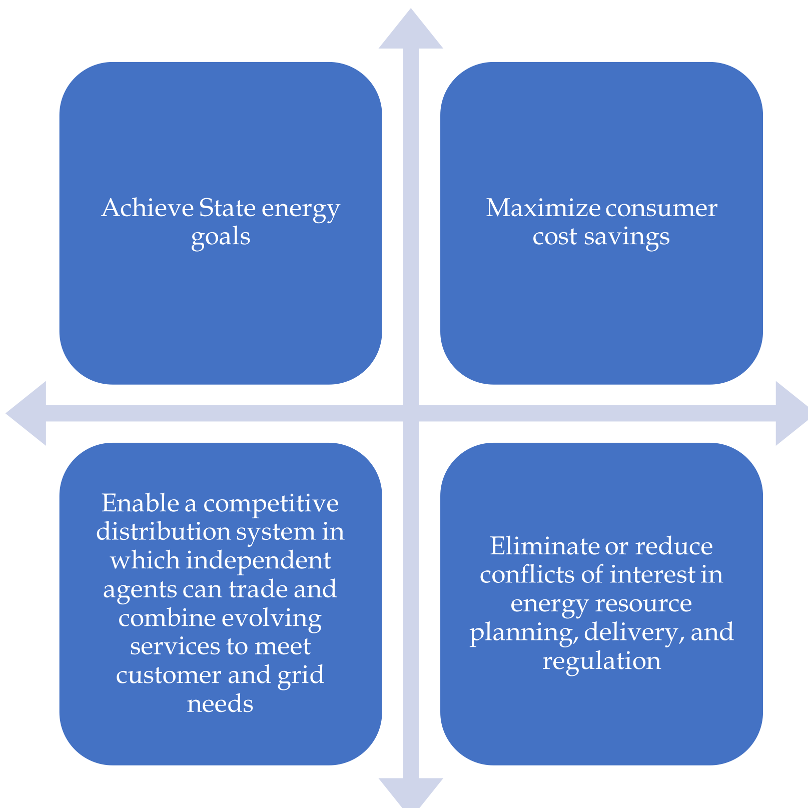
2 Introduction and scope

2.1 Project description

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission on a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. London Economics International LLC ("LEI"), through a competitive sealed proposals procurement,[5] was contracted to perform this study.[6]

The goal of the project is to evaluate the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[7] listed in Figure 2.

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

---

[5] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[6] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[7] House Bill No. 1700 Relating to the State Budget.

The study will help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[8]

2.2 Role of this deliverable relative to others in the project

This deliverable is responsive to Task 2.5.4 in the project scope of work. It analyzes risks to utility valuations for the three IOUs in the State of Hawaii under four regulatory models:

- status quo – the COS model,
- an Outcomes-based PBR model,
- a Conventional PBR + Light HERA model, and
- a Hybrid model as described previously in Task 2.2.1.

Although the Project Team had evaluated four separate regulatory models for Kauai County, preliminary analysis indicated that differences in valuations of KIUC under the four models were insignificant. As mentioned in the Task 2.5.1/2.5.3 report, the differences in revenue requirements between the recommended regulatory models for Kauai County were under 1% for each year of the forecast horizon. This translated to estimates of valuation within 50 basis points for the different models. Furthermore, the risks considered for this report had nearly identical impacts on cash flows for all models because they only have minor differences in costs. This analysis, therefore, did not include KIUC and focused on the risks to valuation for the HECO Companies.

This memo discusses some of the potential risks (namely financial, business, and regulatory risks) identified and described in Task 2.3.3 in more quantitative terms and includes an approach to estimate the magnitude of the potential risks to utility valuations.

It is important to note that the analysis presented in this report is a mostly academic exercise. The Project Team's valuations and assessments of risk are based on the forecasts of revenues and expenses from revenue requirements modeling for Task 2.5.1, with assumptions of fixed capital costs and structures. All estimates also include the utilities' capital expenditures ("capex") plan from the Power Supply Improvement Plan report. In reality, capex planning and financing decisions occur in a more dynamic process. Companies may adjust the timing of investments, raise additional capital, or not pay out dividends to shareholders based on the cash available and planned usage. Given the assumptions made, the numbers should not be taken at face value. However, the analysis is useful as an indicator of potential risks in relative terms.

Furthermore, the risks and their impact on utility finances and rates can be addressed in rate case proceedings. The Project Team assumes a three-year rate cycle for the Conventional PBR model and a five-year rate cycle for the two Outcomes-based PBR models (standalone and hybrid).

[8] Hawaii Contract No. 65595. Scope of Services.

When the base rates are reset, the regulator may consider the changes in risks to the utility and authorize base revenue requirements that appropriately reflect the risk profile. The different rate cycle with various proposed models and the decisions taken by the regulators, therefore, affect risk and valuation for utilities.

3 Valuation

The valuation of a company is necessary to assess the appropriate current value or price during transactions as well as to make prudent decisions regarding investments in assets and financing those investments. The valuation analysis in Task 1.3.1 generated an estimate for the acquisition price during a change in ownership model – e.g., what price would a newly formed co-op have to pay HECO to acquire its assets. For the alternative regulatory models analyzed by the Project Team, a transfer of utility ownership from the HECO Companies or KIUC to a new entity would not be required. However, expected regulatory changes in the future can impact a utility's current value by altering its cash flows, creating uncertainty regarding earnings, and exposing it to specific business or market risks.

It is essential to understand how regulatory changes may affect a utility's value because capital flows towards investments that offer better returns, typically achieved by increases in value from the time of investment. Electric utilities and their regulators must recognize the impact of their decisions on investor returns and the utilities' risk profile. A regulatory environment that promotes value creation[9] is attractive for investors and also beneficial for all stakeholders in such a capital-intensive industry. Regulatory changes that deter investors from making investments result in higher financing costs for the utility and thus raise costs for all ratepayers. This is particularly true in Hawaii where the utilities face both a need to replace aging grid infrastructure and meet ambitious renewable energy targets. For the same reasons, "ensure utility's financial health" was a major criterion in ranking the various regulatory models in Task 2.2.6.

Common Financial Terms and Definitions

This text box outlines the key terms and definitions in the following financial analysis:

- **Discounting:** Discounting is the process of determining the present value of a future payment or a future stream of payments. Due to the time value of money, a dollar today is worth more than a dollar tomorrow. A discount factor, which is a function of time and interest rates, is applied to future dollars to determine their value today.

- **Earnings Before Interest and Tax ("EBIT"):** EBIT is simply revenues minus expenses, excluding tax and interest. It measures the profit a company generates from its operations. By ignoring tax and interest expenses, it focuses solely on a company's ability to make earnings from operations, while excluding variables such as tax burden and capital structure. EBIT is also referred to as operating earnings, operating profit, or profit before interest and taxes.

- **Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"):** EBITDA is a measure of profitability. It indicates earnings prior to the impact of the tax

[9] Value creation for investors refers to factors or activities that lead to an increase in what their investment is worth. Generally, a company creates value for investors if it provides returns that are higher than the cost of capital is traditionally reflected in an appreciation of stock prices. While there are other aspects of value such as brand strength and innovation, this analysis focuses on the financial value to investors.

environment, financing decisions (or capital structure, in terms of debt versus equity), and depreciation of assets. It is calculated as the operating profit, plus the amortization expense and the depreciation expense. It is also calculated as the net profit plus interest, taxes, depreciation, and amortization.

- **Enterprise Value ("EV"):** EV indicates the total value of a firm or the total sum of all claims by both shareholders and debtholders. It is measured as market capitalization plus debt, preferred shares, and minority interest, minus total cash and cash equivalents. One common way of characterizing EV is the total value of purchasing the company in its entirety, based on share price and current debts. This is also the deal value of a merger or acquisition of the whole the target company.

- **Equity Value:** Equity value, or market capitalization, is the value of a company available to shareholders. This contrasts with EV, which also includes the value from debtholders. Relative to EV, Equity Value is EV plus total cash and cash equivalents, minus debt, preferred shares, and minority interest.

- **Free Cash Flow for the Firm ("FCFF"):** FCFF represents the cash available to investors after a company pays all its business costs, invests in current assets (e.g., inventory), and invests in long-term assets (e.g., equipment). FCFF includes bondholders and stockholders when considering the money left over for investors. FCFF is essentially a measurement of a company's profitability after all expenses and reinvestments.

- **Net Income:** Net income is the difference between revenues and cost of business, *including* all depreciation, amortization, interest, and taxes. It is not equivalent to EBITDA. It indicates the final profit that is available to shareholders.

- **Weighted Average Cost of Capital ("WACC"):** WACC is a calculation of a firm's cost of capital in which each category of capital is proportionately weighted. All sources of capital, including common stock, preferred stock, bonds, and any other long-term debt, are included in a WACC calculation. To calculate WACC, multiply the cost of each capital component by its proportional weight and take the sum of the results.

  $$WACC = (E/V) * Re + (D/V) * Rd * (1 - Tc)$$

  where,
  Re = cost of equity
  Rd = cost of debt
  E = market value of the firm's equity
  D = market value of the firm's debt
  V = E + D
  Tc = corporate tax rate

Source: Investopedia, Dictionary, see terms for "discounting," "enterprise value," "FCFF," "WACC" net income," "EBITDA," available at: https://www.investopedia.com/.

3.1 Valuation methodologies

There are several approaches to valuation commonly used in the industry, each of which is based on different assumptions about what drives value. Broadly, these approaches can be categorized into three methodologies: (i) DCF valuation, (ii) relative valuation, and (iii) contingent claim valuation.[10]

In **DCF valuation**, the company (or asset) is valued based on the present value of the cash flows it is expected to generate in the future. The future cash flows are discounted at a rate that reflects the level of risk associated with the projected cash flows. Intuitively, the DCF approach defines a company's value based on the level, timing, and volatility of cash flows that investors can expect. It can be used to value either the entire firm or just the equity stake (value to shareholders). It is based on company fundamentals such as current cash flows, the expected growth rate of those cash flows, and a company-specific discount rate. Since the fundamentals are derived from current operations, capital structure and costs, and reasonable future plans, the DCF methodology represents an estimate of the intrinsic value of a company.

In contrast, **relative valuation** estimates value based on how "comparables" (similar assets or companies, ideally in the same industry) are priced by the market. The target company is compared to the market valuations of a peer group of publicly traded companies based on standardized variables like earnings multiples, revenue multiples, or book value of assets. An alternate approach is to rely on the actual valuation of comparables reflected in recent merger and acquisition activity. Thus, instead of the fundamentals of the firm, relative valuation relies on the market's perception to determine value.

Recently, a third approach to valuation is gaining in popularity. **Contingent claim valuation** seeks to address a shortcoming in DCF valuation, which assumes a static operating strategy for the company to derive its cash flow projections. In reality, companies may change their operating strategy in response to market conditions to either take advantage of favorable developments or mitigate losses when risks materialize. The contingent claim valuation approach uses option pricing models to add an option premium to DCF valuation. A summary of the basics of option pricing theory is provided in the text box below.

Option Pricing Theory

An option is a contract that is valid for a pre-specified length of time which gives the buyer the right to buy or sell a pre-specified quantity of an underlying asset at a fixed price, called a ***strike price***. Since it is a right and not an obligation, the holder can choose to exercise the right when it is beneficial and let it expire otherwise. An option is a type of derivative security because its value is based on the underlying asset. Options can be either call or put options.

A ***call option*** gives the buyer the right to *buy* the underlying asset at the strike price. The holder would only exercise a call option when the actual asset value is higher than the strike price.

[10] Damodaran, Aswath. *Applied Corporate Finance*. New York: John Wiley & Sons, 1999. Print.

When the underlying asset's value grows, the difference between the actual asset value and the strike price also grows, increasing the value of a call option (call price).

A ***put option*** gives the buyer the right to *sell* the underlying asset at the strike price. Thus, the holder would only exercise a put option when the strike price is higher than the actual asset value. The value of a put option (put price) increases when the underlying asset's value falls.

Other factors that impact the value of an option are its strike price, the time to expiration, the risk-free interest rate, and the volatility of the underlying asset. The impact of the variables affecting call and put prices are summarized in the table below.

Factor	**Call Value**	**Put Value**
Increase in underlying asset's value	Increases	Decreases
Increase in strike price	Decreases	Increases
Increase in the variance of an underlying asset	Increases	Increases
Increase in time to expiration	Increases	Increases
Increase in interest rates	Increases	Decreases
Increase in dividends paid	Decreases	Increases

Source: Damodaran, Aswath. *Applied Corporate Finance*. New York: John Wiley & Sons, 1999. Print.

3.2 Chosen approach

The Project Team considered all three methods and selected DCF valuation for this analysis through a process of elimination. In Task 1.3.1, the Team considered both DCF and relative valuation. The analysis was more typical of valuations conducted for companies in all sectors because it considered a change in ownership. In Task 1.3.1, the Team used two types of relative valuation, trading comparables, and comparable transactions, and compared the results. The Team then verified the results of relative valuation approach after conducting a more detailed cash flow analysis for Task 1.6.2.

The Project Team believes that the limitations of the **relative valuation approach** are amplified in the context of this analysis, which involves changes in regulation rather than ownership and focuses on risks. The relative valuation approach relies on an unbiased selection of a peer group of comparables and how closely they resemble Hawaii's utilities. In Task 1.3.1, the trading comparables analysis for the HECO Companies was conducted using a peer group of 9 utilities. The initial list was narrowed down by defining the comparables as being vertically-integrated, publicly listed, and with similar levels of electricity sales and credit ratings. To estimate valuation and risks to valuation under the recommended regulatory models, even narrowing the list further to just the utilities that are subject to performance-based regulation ("PBR") regimes is not sufficient. The particular elements of PBR design such as performance targets, the magnitude of rewards and penalties in Performance Incentive Mechanisms ("PIMs"), and Earnings Sharing Mechanisms ("ESM") are key drivers of risks to utility valuation. Therefore, compiling an appropriate list of comparables is exceptionally challenging and limits the practicality of the relative valuation approach. Thus, relative valuation approach was not used.

The **contingent claims valuation approach** offers promise in its ability to incorporate the flexibility available to the utility as more information becomes available but is also hamstrung by the difficulty to obtain the data necessary for key inputs. As Hawaii moves to a 100% renewables future, utilities could adjust their resource plans if the costs of an existing technology decrease faster than expected currently or if a revolutionary new technology is developed in the future. The challenges of reliably operating a grid with a substantially higher penetration of intermittent resources may also differ from current expectations and require either higher or lower levels of investments than planned. Real options can estimate the value of the utility's ability to revise its resource or investment plans and thus improve its profitability and cash flows in the future. However, there is not sufficient information available to value them accurately given the length of the forecast horizon. Therefore, this approach was not utilized.

DCF valuation is widely used and easily accommodates sensitivity analyses. The Project Team adjusted the input parameters of its DCF models for each utility and regulatory model to reflect the risks under each recommended regulatory model and analyzed the impact on utility valuation. Section 4.1 provides a discussion of the risks and how they impact DCF models.

DCF analysis can be used to value either the entire firm (enterprise value) or just the equity's share of the company (equity value). Enterprise value ("EV") represents the value to all investors of the company – the lenders/bondholders who have fixed claims and the equity investors who have residual claims.[11] It is calculated by discounting the projected cash flows to the firm (what remains after covering operating expenses, investments, and taxes) using the company's WACC.

As a regulated utility, the HECO Companies' capital structure and rate of return to equity investors must be approved by the Public Utilities Commission ("PUC").[12] Unlike unregulated corporations, utilities cannot merely increase the company's leverage beyond a level that the PUC would allow or aggressively expand operating income to increase the value to shareholders. Utilities can benefit both their shareholders and their ratepayers by lowering risks and thus receiving more favorable terms on debt financing.[13] Therefore, this analysis estimates the various risks under the recommended regulatory models in terms of their impact on the utilities' EV to evaluate the risks to all investors. Utility valuations in this report are as of 2018 with a 27-year horizon.

3.3 Components of DCF valuation

There are three key input parameters in determining a company's value – the expected cash flows, the relevant discount rate, and an expected growth pattern. Over an extended period of time, they are also inter-related. Factors that impact the expected cash flows would likely also alter various

---

[11] Ibid.

[12] The Project Team assumed a fixed capital structure over the entire forecast horizon (2018-2045) for revenue requirements projections in Task 2.5.1 and the baseline valuations for this report.

[13] There is an inverse relationship between interest rates on debt and equity risk premium. See further explanations and calculations in HECO Supplemental Testimonies, Exhibits & Workpapers, Book 2, HECO ST-28, Docket No. 2016-0328, Appendix A, page 8.

profitability and liquidity ratios. If these ratios change significantly, rating agencies can revise their credit rating on the company's debt and thus impact the cost of debt. Changes in interest rate impact equity risk premium and consequently the cost of equity, as described in Section 4.1.1.

i) **Expected cash flows** in the future are discounted to estimate the utility's valuation. For an estimate of EV, the relevant cash flow metric is FCFF. It represents the cumulative cash flows to all investors, both bondholders and equity shareholders. It is calculated by subtracting tax expenses, capital expenditures ("capex"), and the change in working capital from EBIT, and adding back depreciation. These calculations are based on the projections of electricity sales, revenues, operations, and maintenance ("O&M") expenditures planned capex, depreciation, and working capital from revenue requirement calculations as discussed in Tasks 2.5.1 and 2.5.3.

ii) A **discount rate** is necessary to adjust the expected future cash flows to represent what they are worth today. The Project Team discounted the forecasted FCFF for future years up to 2045 using the utilities' WACC, as used in the revenue requirement calculations in Tasks 2.5.1/2.5.3. This discount rate is especially appropriate for this analysis since the Project Team assumed constant capital costs and structure throughout the forecast horizon in projecting revenue requirements in Tasks 2.5.1/2.5.3, as these projections formed the foundations of the analyses in this report.

iii) **Expected growth** is used to estimate cash flows beyond the forecast horizon. The Project Team's analysis includes forecasts of revenues and cash flows until 2045. Given the long useful life of utilities' physical infrastructure and a regulated natural monopoly business model, it can reasonably be expected that cash flows to the company will continue beyond 2045. Terminal value represents the value, in 2045, of the cash flows beyond the forecast horizon. An important component of estimating terminal value is the expected growth of cash flows beyond 2045. The Project Team used the growth rate estimated by JP Morgan for its valuation of the HECO Companies during the NextEra merger proceedings. JP Morgan's terminal growth rate range was 1.15% to 1.65%.[14] The Project Team used 1.40%, the average value of JP Morgan's range, in its analyses.

   Terminal value is obtained by dividing the estimated cash flow for the year after the last year of the forecast (in 2046 for this analysis) by the difference between WACC and the expected growth rate. The 2046 cash flow is calculated by multiplying the cash flow for 2045 by the growth rate.

Using the DCF approach and the same assumptions from Task 2.5.1, the Project Team estimated the NPV of FCFF as utility valuations under the base scenario. The Team then estimated the potential magnitude of some risks to utility valuation as the percentage change in the NPV of cash flows under the different scenarios reflecting each risk, as described more in Section 4.

---

[14] "NextEra Energy, Inc. Form S-4, Registration Statement under the Securities Act of 1993." *Securities and Exchange Commission. January 8, 2015.* Web. Accessed September 27, 2015. <https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm>

4 Risks to utility valuation

In any business and industry, companies face several risks that could impact their operations, profitability, and costs of financing. The risks could be due to macroeconomic variables that affect all companies in all industries, or new trends emerging within a particular industry, or even events that are likely to impact just a specific company. Changes in interest rates by the Federal Reserve will affect borrowing costs across the economy. Improvements in efficiency and costs for certain technologies like solar photovoltaic panels and batteries have a more focused impact on the power sector. Poor decisions by the company management regarding financing and capital investments may damage the company in question.

The risks that companies face can be thought of as having two dimensions – probability and magnitude. The likelihood of whether a particular scenario will actually become a reality is typically a qualitative assessment. The magnitude of risk has to do with the size of its impact if it does happen.

Also, the impact can be either positive or negative. For instance, there are two types of regulatory risks discussed in Section 4.1.5 – rate freezes and reward/penalty levels of PIMs. A potential rate freeze only has a downside impact, in that there is an adverse impact on cash flows and valuation from the utility's perspective. However, PIMs have both upside and downside potential, depending on whether they are symmetric or asymmetric in design. A symmetric PIM with high levels of penalties and rewards has a higher risk for the utility if it is not able to meet the performance targets; however, the potential rewards are also higher.

In contrast, lower levels of penalties and rewards imply lower downside risk for the utility but also lower upside potential. This report will only focus primarily on the potential downside of certain risks, in terms of magnitude. The qualitative assessments of these risks are provided in the Task 2.3.3 report. For this analysis, "riskier" refers to the higher potential downside in terms of magnitude – or a more significant potential decline in the NPV of projected cash flows.

4.1 Risk categories

As described in some detail in Task 1.3.1, the risks that companies face can be grouped into five categories. The risk categories along with a general example are detailed below.

Risk category	Example
Financial	A company with volatile FCFF that is not required to file audited financial statements.
Business	A company in an industry with low barriers to entry and threats to sales due to new trends in the industry.
Macroeconomic	Interest rate hikes by the Federal Reserve lead to higher borrowing costs for all companies.
Operational	The development of a new technology forces existing companies to change their business models.
Regulatory	Introduction of new regulations regarding environmental standards.

4.1.1 Financial risk

Financial risk pertains to the level of uncertainty regarding a company's cash flows. They are affected by a company's expected revenues, capital structure, costs of financing, ongoing operating expenses, and planned capital expenditures. Various financial ratios regarding profitability, leverage, and liquidity are monitored to evaluate this risk. In the base scenario, the utilities' capital structures and costs are assumed to be fixed throughout the forecast horizon. However, due to differences in revenues and expenditures under different regulatory models, profit margins and leverage ratios vary across different models. Financial risk evaluates several characteristics regarding cash flows, including the uncertainty, timing, dependence on the accounting method used, and the level of oversight (such as from an auditor, shareholders, or the US Securities and Exchange Commission).

Several measures can help address financial risk. Regulatory accounting allows utilities to defer some expenses and revenues to match the timing of their inclusion in revenue requirements and rates. This helps to smoothen out any volatility. Also, utilities can be shielded from risks regarding variation in fuel and purchased power costs by including adjustments in the final revenue requirements that allow them to fully recover these costs through rates. Finally, profitability and leverage analyses help to assess the level and volatility of cash flows. Rating agencies evaluate all factors for the company against its industry peers to evaluate financial risk. Higher levels of risk are typically reflected in lower credit ratings and higher costs of capital.

Financial risk, as reflected in a change in the cost of capital, could impact all three components of DCF valuation. The utility's expected cash flows are directly affected because the operating income component of revenues is obtained by multiplying the rate base by WACC. Depending on the timing of the change in WACC, it may justify using a different discount rate than the base WACC. While the growth rate would not change, a change in WACC would alter the terminal value used in the valuation.

The HECO Companies are currently rated BBB- by S&P and Baa2 by Moody's, indicating a medium credit quality.[15] Both ratings companies also have a "stable" outlook for HECO's credit ratings. Some of the financial metrics associated with the credit ratings as well as the corporate yields, or cost of debt, are shown in Figure 3. In estimating the financial risks to utility valuation, the Project Team compared the financial ratios of the HECO Companies over the forecast horizon under each regulatory model. If the ratios deteriorated, the Project Team assumed that the cost of debt would increase by a certain amount as shown in the last column in Figure 3.

---

[15] S&P Global Market Intelligence. *Corporate Issuance – Credit Ratings*. Accessed September 30, 2018.

Figure 3. Financial ratios and interest rates by credit rating

Credit Rating	EBITDA/Interest Expense	EBITDA Margin	Operating Margin	Interest Coverage	Interest rate on senior debt	Interest rate - Δ vs. Baa
Aaa	11.5	30.6%	25.4%	16.0	4.53%	0.74%
Aa	13.9	19.5%	17.4%	16.0	4.70%	0.57%
A	10.7	15.8%	14.9%	8.6	4.97%	0.30%
Baa	6.3	13.9%	12.0%	5.4	5.27%	0.00%
Ba	3.7	13.3%	11.5%	3.7	6.90%	(1.63%)
B	1.9	11.2%	9.0%	1.9	10.38%	(5.11%)
Caa-C	0.7	7.0%	4.6%	0.7	12.92%	(7.65%)
HECO	6.3	19.0%	10.8%	3.6	3.25% - 6.50%	
HELCO	7.1	25.3%	13.7%	3.9	3.10% - 6.50%	
MECO	6.5	19.1%	12.0%	4.1	3.10% - 5.65%	

Source: HECO Annual Financial Report to the PUC 2017. Moody's Data Report, September 2017. S&P Capital IQ.

A change in the cost of debt also leads to a change in the equity risk premium and hence the cost of equity. The relationship between equity risk premium and the cost of debt is denoted by the following equation:[16]

$$Equity\ Risk\ Premium = -0.5755 * Cost\ of\ debt + 0.0775$$

Based on the above formula and the assumption that the capital structure remains fixed, the cost of capital for each credit rating is shown in Figure 4.

Improvements in the risk profile and credit ratings result in relatively small decreases in WACC whereas a ratings downgrade has a much more significant and negative impact on WACC. The Project Team estimates that an "Aaa" credit rating would lower HECO's WACC by 47 basis points, but a downgrade to a "Ba" rating could increase its WACC by nearly 100 basis points. The downside risk is much higher than the upside because the HECO Companies' current rating is towards the lower end of the "Investment Grade" ratings. Investment grade indicates that the entity is likely to meet payment obligations on its debt issuances and includes ratings of BBB- or higher by S&P or Baa3 or higher by Moody's. As certain financial institutions are only allowed to invest in investment grade securities, it is important to ensure that the HECO Companies' credit rating does not fall into the "junk bond" category.

Figure 4. Cost of capital by credit rating - Indicative

Credit Rating	Corporate Yields - 30 year	Corporate Yields - Δ vs. Baa	ROE	WACC		
				HECO	HELCO	MECO
Aaa	4.53%	(0.74%)	9.19%	7.10%	7.32%	6.97%
Aa	4.70%	(0.57%)	9.26%	7.21%	7.43%	7.08%
A	4.97%	(0.30%)	9.37%	7.38%	7.60%	7.24%
Baa	5.27%	0.00%	9.50%	7.57%	7.79%	7.43%
Ba	6.90%	1.63%	10.19%	8.61%	8.84%	8.46%
B	10.38%	5.11%	11.67%	10.83%	11.08%	10.65%
Caa-C	12.92%	7.65%	12.75%	12.46%	12.71%	12.24%

[16] HECO. *Docket No. 2016-0328. Supplemental Testimonies, Exhibits & Workpapers – Book 2. HECO ST-28, Appendix A.* p8.

4.1.2 Business risk

Business risk pertains to factors affecting the utility's profits through either revenues or expenses. As a regulated monopoly, utilities are less exposed to business risks arising from competition or fluctuations in commodity prices than a typical company. However, utilities in many jurisdictions are increasingly facing the threat of flat or declining load (or sales). If actual electricity sales in Hawaii are lower than forecasted, it would also impact cash flows and valuation. There will be an impact even if a price cap or revenue cap is used.[17] In a price cap, a fall in overall sales would mean lower revenue requirements for the utilities. A revenue cap may protect the utility from falling electricity sales within a regulatory period because revenue requirements would escalate at a fixed rate from the going-in rate. However, the forecast horizon for this analysis is over 25 years so the rates for future regulatory periods would decline relative to the base scenario. Consequently, if there is a long-term decline in sales, the utilities' revenue requirements and cash flows would decrease. Furthermore, a decrease in revenues could also lead to financial risks if the profitability and liquidity ratios decline sufficiently to warrant a credit ratings downgrade.

The Hybrid model includes an additional business risk because the Team assumes that platform service revenues ("PSR") from the DSPP model will be a significant source of utility revenues under this model. In the base scenario, the Team assumes that PSRs would double every 5 years, based on a review of the analysis presented in New York's Reforming the Energy Vision proceedings. However, this expected growth is primarily based on the potential and observed increase of similar revenues in other industries. The utilities' revenues, cash flows, and valuation are exposed to the risk that actual growth rate of PSRs will be slower than current expectations.

As mentioned previously in Section 2.2, the regulator and the HECO Companies are likely to make adjustments at the end of each rate period as new business risks become apparent.

4.1.3 Macroeconomic risk

Macroeconomic risk refers to sovereign credit rating and interest rates in the US. S&P would only rate a US-based company higher than the US if it believed that the company had sufficient creditworthiness to withstand a sovereign default by the US.[18] Since this risk category is shared across all regulatory models, it is not considered for this analysis.

4.1.4 Operational risk

Operational risks reflect the threat to the utility business due to technology change, availability of skilled labor, and environmental risks. Again, the Project Team assumes that these risks are broadly shared across all three recommended regulatory models.

---

[17] For more discussion about price vs. revenue cap, please refer to Task 2.1.1.

[18] S&P Global. *General Criteria: Ratings above the sovereign – Corporate and government ratings: Methodology and Assumptions.* November 19, 2013.

4.1.5 Regulatory risk

Regulatory risks arise if the market perceives that there is a risk of change in electricity rate regulation that could affect cash flow for utilities. Although the recommended models represent a shift from the current regulatory framework, the Project Team does not evaluate those scenarios as risks but as certain changes. Often, however, changes in utility regulation are accompanied by rate freezes as regulators seek to avoid volatility to consumers during the transition. Also, elements of PBR design such as the magnitude of rewards, penalties, and ESM are not yet fixed and will likely have a major impact on the utility's profitability and risk profile. Therefore, the Project Team's analysis includes evaluation of regulatory risks of a three-year rate freeze and actual rewards for PIMs at half of the maximum level under the base scenario.

A rate freeze is a commonly used regulatory tool. In a survey of 28 states in the US, 11 employed a rate freeze.[19] The Project Team assumes that the PUC would fix rates (and therefore utility revenues) for the first regulatory period of PBR. However, the length of the regulatory period varies across the different recommended regulatory models – 3 years for Conventional PBR and 5 years for the two Outcomes-based PBR models. For the sake of consistency across the models, the Team assumes a rate freeze during the first three years once PBR is implemented, i.e., 2020 to 2022, for all regulatory models.

The Project Team's base scenario from Tasks 2.5.1 and 2.5.3 also assumes that the utilities can achieve all their performance targets and earn the maximum reward amount under each PBR model. In reality, the actual rewards earned (or penalties received) by the utility may vary based on many factors, including the level of performance targets, the utility's investment plans, and costs of different technologies. For this report, the Project Team evaluated the sensitivity of utility valuations to incremental earnings from PIMs by comparing valuations under two scenarios:

i) actual rewards earned = maximum rewards possible (base scenario), and

ii) actual rewards earned = half of the maximum rewards.

[19] Zarakas et al. *Performance Based Regulation Plans – Goals, Incentives, and Alignment.* The Brattle Group, December 2017.

4.2 Risks by regulatory model

The Project Team identified several potential risks under each recommended regulatory model. The Team then categorized those risks as either financial or business risk and made a qualitative and quantitative assessment of their potential impact on the components of DCF valuation. The potential impact of the risk on utility valuation was estimated as the change in utility valuation with respect to the base valuation. The various risks and the possible fall in utility values are summarized below in Figure 5.

The Hybrid model contains an additional risk category due to the importance of PSRs for utility cash flows. PSRs not only constitute an additional risk category but in fact the largest one. A rate freeze is also a major risk to utilities – even with deferred cost recovery after the three-year rate freeze, utility valuations are substantially lowered. Interestingly, lower than expected electricity sales represent a smaller risk to utility valuation than lower levels of performance incentives under PBR.

Figure 5. Potential decrease in valuations by utility, risk category, and regulatory model

($000s)	Conventional PBR + Light HERA	Outcomes-based PBR	Hybrid
Financial Risk			
Credit risk			
HECO	-	-	-
HELCO	-	-	-
MECO	-	0.8%	-
Business Risk			
Lower than expected sales			
HECO	0.1%	0.1%	0.1%
HELCO	0.1%	0.2%	0.2%
MECO	-	-	-
Slower growth of platform revenues			
HECO	N/A	N/A	2.4%
HELCO	N/A	N/A	2.0%
MECO	N/A	N/A	6.4%
Regulatory Risk			
Rate freeze for the first three years			
HECO	2.1%	2.4%	1.9%
HELCO	1.0%	0.8%	0.8%
MECO	3.1%	4.9%	3.7%
Actual rewards = half of maximum available rewards			
HECO	0.9%	0.8%	0.3%
HELCO	0.6%	0.3%	0.2%
MECO	1.2%	1.9%	0.9%

Note – valuation as of 2018 with a 27-year horizon; discount rate of 7.57%, 7.79%, and 7.43% used for HECO, HELCO, and MECO respectively.

4.2.1 Outcomes-based PBR model

4.2.1.1 Financial risks

In the base scenario, the financial risks (or the risk related to the utility's cash flows) under the Outcomes-based PBR model are minimal for HECO and HELCO. Both utilities are expected to maintain consistent financial performance throughout the forecast horizon. In fact, financial risk is estimated to decrease for HELCO after 2030 and for HECO after 2038 due to improving operating margins and interest coverage ratios.

For MECO, there are some financial risks between 2025 and 2030 as financial ratios deteriorate. The risk arises due to ESM – excess earnings between 2020 and 2025 are returned to ratepayers between 2025 and 2030, constraining MECO's cash flows. There is a risk of a credit downgrade during this time.

Nevertheless, since the profit margins and interest coverage ratio recover after 2030, the overall financial impact is limited. The Project Team expects a 1.63 percentage-point increase in interest rates for MECO between 2025 and 2030, also impacting the discount rate for DCF valuation. With these changes in parameters, the Team estimates that the financial risk due to ESM could lower MECO's valuation by about 0.8%.

4.2.1.2 Business risk

A potential business risk is lower electricity sales. The Project Team estimated this impact of weaker sales on utility valuation. The Team analyzed the risk to utility valuation if actual electricity sales after 2025 were 5% lower than the HECO Companies' forecast. If future sales are lower than expected, the Project Team estimates that utility valuation would decrease by 0.1% for HECO and 0.2% for HELCO but not be affected significantly for MECO. In MECO's case, lower revenues from this level of sales decline are offset by decreases in O&M and tax expenses. This difference relative to HECO and HELCO is driven by the particular mix of revenues, expenses, and planned capex.

4.2.1.3 Regulatory risk

As described in Section 4.1.5, the Project Team considered two types of regulatory risks: rate freezes and the level of rewards and penalties under the PIMs.

The impact of a rate freeze on utility valuation was substantial. If the PUC imposed a three-year rate freeze during the first PBR generation (or between 2020 and 2022) with no provisions for the utility to recover expenses in the interim, the utilities could lose over 10% of their value. Even if the utilities are allowed to recover the difference between frozen rates and actual revenue requirements throughout 5 years after the rate freeze, there is still a significant regulatory risk. With a delayed cost recovery, a three-year rate freeze could lower utility valuation by about 2.4% for HECO, 0.8% for HELCO, and 4.9% for MECO. In practice, utilities would adjust expenditures and capex plans in response to a rate freeze and the impact on cash flows and valuation would be more limited.

Another regulatory risk considered in this analysis is the level of rewards and penalties in PIMs. It is not sufficient to merely set performance targets that are achievable – the corresponding rewards and penalties must also be high enough to incent the utility to manage its operations such that those targets are indeed achieved. Over the course of time, even small changes in incentive levels can have a significant impact on the utilities' valuations. If the utilities are only able to earn half of the available incentives, utility valuations would decline by $26.8 million for HECO, $3.0 million for HELCO, and $12.3 million for MECO.

4.2.2 Conventional PBR + Light HERA model

4.2.2.1 Financial risks

Compared to the two Outcomes-based PBR models, the impact of ESM is typically more limited under Conventional PBR because the revenue cap mechanism helps to limit excess utility earnings. The profitability and leverage ratios deteriorate for some isolated years but recover immediately after. As a result, the Project Team does not expect additional financial risks or a need to adjust the costs of capital under this model. Therefore, the Project Team does not assume financial risks to significantly impact utility valuations under the Conventional PBR + Light HERA model.

4.2.2.2 Business risk

If electricity sales after 2025 are 5% lower than expected, utility valuation would decrease by 0.1% for both HECO and HELCO but not be affected significantly for MECO. In MECO's case, lower revenues from this level of sales decline are offset by decreases in O&M and tax expenses. Furthermore, business risk is lower under the Conventional PBR + Light HERA model compared to the Outcomes-based PBR model because it already includes a revenue cap mechanism that limits revenues and cash flows regardless of load growth.

4.2.2.3 Regulatory risk

Again, a three-year rate freeze with no provisions for deferred cost recovery could lower the utilities' valuation by 10%. If deferred cost recovery is allowed, a three-year rate freeze could lower utilities' valuation by about 2.1% for HECO, 1.0% for HELCO, and 3.1% for MECO. Generally, the risk of a rate freeze is lower under this regulatory model compared to the two Outcomes-based PBR models because it includes a revenue cap mechanism that limits the increase in customer rates.

If actual earnings from performance incentives are only 50% of the maximum available rewards, utility valuations decline by 0.9% for HECO, 0.6% for HELCO, and 1.2% for MECO.

4.2.3 Hybrid model

4.2.3.1 Financial risks

Financial risks under the Hybrid model are minimal in the base scenario for HECO and HELCO. The utilities' profitability and leverage ratios generally improve under this regulatory model with respect to the status quo. The reduction in costs associated with system operations and dispatch as well as additional infrastructure investments to enable the DSPP result in additional positive cash flows.

4.2.3.2 Business risk

If electricity sales after 2025 are 5% lower than expected, utility valuation would decrease by 0.1% for HECO and by 0.2% for HELCO but not be affected significantly for MECO. Another business risk under the Hybrid model is the assumed growth of PSRs. In the base case, PSRs are assumed to double every 5 years after the DSPP component is introduced. If PSRs only grow half as fast, the Project Team expects valuations to decrease by about 2.4% for HECO, 2.0% for HELCO, and 6.4% for MECO. This indicates a need to carefully craft the PIMs and transition to the DSPP component after the potential of platform-based markets and associated revenues to the utility is more fully understood. However, it is also important to note that the utility and regulators can adapt their responses to actual growth in PSRs relative to the current expectations.

4.2.3.3 Regulatory risk

A three-year rate freeze with no provisions for deferred cost recovery could lower the utilities' value by about 15%. If deferred cost recovery is allowed, a three-year rate freeze could reduce utility valuation by about 1.9% for HECO, 0.8% for HELCO, and 3.7% for MECO.

50 % lower earnings from performance incentives compared to the base scenario would lower utility valuations by 0.3% for HECO, 0.2% for HELCO, and 0.9% for MECO.

5 Appendix A: Scope of work to which this deliverable responds

2.5.4 Analysis of any issues in the regulatory model that could impact the valuation of an electric utility and identify key risks to utility valuations for each regulatory model. CONTRACTOR shall provide an analysis of any variation to the valuation of an electric utility caused by a change in regulatory model.

DELIVERABLE FOR TASK 2.5.4. CONTRACTOR shall provide its conclusions and all work related to an analysis of issues in the regulatory model that could impact the valuation of an electric utility. CONTRACTOR shall assess key risks to utility valuations for each recommended regulatory model and develop an approach to estimate the magnitude of these risks. CONTRACTOR shall include a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.4 to the STATE for approval.

6 Appendix B: List of works consulted

Damodaran, Aswath. *Applied Corporate Finance*. New York: John Wiley & Sons, 1999. Print.

Hawaii Electric Light Company. *Annual Report of the Hawaii Electric Light Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Hawaii Electric Light Company. *Docket No. 2015-0170. Application of Hawaii Electric Light Company for Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits.* September 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 1.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 2.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 3.* December 2016.

Hawaiian Electric Companies. *PSIP Update Report – Book 4.* December 2016.

Hawaiian Electric Company. *Annual Report of the Hawaiian Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Hawaiian Electric Company. *Docket No. 2016-0328. Application of Hawaiian Electric Company for Approval of General Rate Case and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits. HECO-3203.* December 2016.

Hawaiian Electric Company. *Docket No. 2016-0328. Application of Hawaiian Electric Company for Approval of General Rate Case and Revised Rate Schedules and Rules. Supplemental Testimonies Exhibits, and Workpapers. Book 2. HECO ST-28.* February 2018.

Kauai Island Utility Cooperative. *2016 Annual Report to the PUC.* March 2017.

Kauai Island Utility Cooperative. *2016 Annual Report.*

Kauai Island Utility Cooperative. *2017 Capital Improvements Program for Ensuing Five Years.* December 2016.

Kauiai Island Utility Coopeative. *Consolidated Financial Statements – December 31, 2016 and 2015.* April 2017.

Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters. Volume 1.* June 2009.

Kauai Island Utility Cooperative. Docket No. 2009-0050. *Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules, and Other Ratemaking Matters.* June 2009.

Maui Electric Company. *Annual Report of the Maui Electric Company to the Public Utilities Commission, State of Hawaii, for the year ending December 31, 2016.* May 2017.

Maui Electric Company. *Docket No. 2017-0150. Application of Maui Electric Company for Approval of Rate Increases and Revised Rate Schedules and Rules. Direct Testimonies and Exhibits.* October 2017.

"NextEra Energy, Inc. Form S-4, Registration Statement under the Securities Act of 1993." *Securities and Exchange Commission. January 8, 2015.* Web. Accessed September 27, 2015. <https://www.sec.gov/Archives/edgar/data/753308/000119312515005172/d846219ds4.htm>

State of Hawaii Department of Business, Economic Development, and Tourism. Research and Economic Analysis. *2016 The State of Hawaii Data Book: A Statistical Abstract*. November 2017.

State of Hawaii Public Utilities Commission. *Docket No. 2009-0050. Application of Kauai Island Utility Cooperative for Approval of Rate Changes and Increases, Revised Rate Schedules and Rules,*

Wahlen, James, Jefferson Jones and Donald Pagach. "Intermediate Accounting: Reporting and Analysis." South-Western Cengage Learning.

Williams, Kevin T. "The Business Case for Co-Op Acquisitions." *Public Utilities Fortnightly – Fortnightly Magazine*, January 2005. Web. <https://www.fortnightly.com/fortnightly/2005/01/business-case-co-op-acquisitions>

Identification of funding mechanisms for each regulatory model

prepared for the Hawaii Department of Business, Economic Development & Tourism ("DBEDT") by London Economics International LLC

September 28, 2018

London Economics International LLC ("LEI") was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This document, Task 2.5.5, is one of several working papers issued as part of this engagement. It provides an overview of the funding mechanisms for three alternative regulatory models to the status quo: Outcomes-based performance-based regulation ("PBR"), Conventional PBR with Light Hawaii Electric Reliability Administrator ("HERA"), and Outcomes-based PBR with the Distributed System Platform Provider ("DSPP") and Independent Grid Operator ("IGO").

Table of contents

London Economics International LLC
717 Atlantic Avenue, Suite 1A
Boston, MA 02111
www.londoneconomics.com

contact:
Gabriel Roumy/Shrutika Sainani
+1 (617) 933-7225
gabriel@londoneconomics.com

Table of figures

contact:
Gabriel Roumy/Shrutika Sainani
+1 (617) 933-7225
gabriel@londoneconomics.com

List of acronyms

BQDM	Brooklyn-Queens Demand Management
CAISO	California ISO
Capex	Capital expenditure
CFC	Capital Funding Chart
ConEd	Consolidated Edison
DBEDT	Hawaii Department of Business Economic Development and Tourism
DCA	Division of Consumer Advocacy
DER	Distributed energy resource
DSO	Distribution system operator
DSP	Distributed System Platform
DSPP	Distributed System Platform Provider
EAC	Early Amortization Charge
EAM	Earnings Adjustment Mechanism
EAS	Energy Administration Service
EAWCC	Early Amortization Working Capital Charge
EPSFC	Early Payment Shortfall Funding Charge
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
HECO	Hawaiian Electric Company
HEI	Hawaiian Electric Industries
HELCO	Hawaii Electric Light Company
HERA	Hawaii Electric Reliability Administrator
IGO	Independent Grid Operator
ISO	Independent system operator
ISO Tariff	ISO New England Inc. Transmission, Markets, and Services Tariff
ISO-NE	ISO New England
LEI	London Economics International LLC
LSE	Load Serving Entity
MECO	Maui Electric Company
MPIR	Major Project Interim Recovery
MS	Market Support
NERC	North American Reliability Corporation
NY PSC	State of New York Public Service Commission
NYISO	New York ISO
O&M	Operating and maintenance
OATT	Open Access Transmission Tariff
Opex	Operating expenditure
PBR	Performance-based regulation
PIM	Performance incentive mechanisms

PJM	PJM Interconnection
PSR	Platform Service Revenue
PUC	Public Utilities Commission
PUCT	Public Utilities Commission of Texas
RAA	Reliability Assurance Agreement
RAM	Rate Adjustment Mechanism
RAS	Reliability Administration Service
RBA	Revenue Balancing Account
RE	Reliability Entity
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
Totex	Total expenditure
UK	United Kingdom

1 Executive Summary

London Economics International LLC, together with Meister Consultants Group (the "Project Team"), was contracted by the Hawaii Department of Business Economic Development and Tourism ("DBEDT") to conduct a study that will evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the State in achieving its energy goals. This working paper, which corresponds to Task 2.5.5 in the project scope of work, provides an evaluation of the potential funding mechanisms for three alternative regulatory models to the status quo, namely the Outcomes-based performance-based regulation ("PBR") model, the Conventional PBR with Light Hawaii Electric Reliability Administrator ("HERA") model, and the Outcomes-based PBR with the Distributed System Platform Provider ("DSPP") and Independent Grid Operator ("IGO"), or the Hybrid model. It also includes an overview of the direct and indirect cost to customers for each model.

1.1 Outcomes-based PBR

Under the Outcomes-based PBR model, the means by which utilities fund their costs would be no different than the way by which utilities recover costs under the status quo. In other words, utilities would continue to employ private financing mechanisms (i.e., short- and long-term debt, and equity), as well as cost recovery through revenue requirements. Hawaii's existing legal framework also has a series of further mechanisms in place that utilities employ to recover capital expenditures ("capex"), such as the Major Project Interim Recovery ("MPIR") adjustment mechanism, as introduced through the 2017 Decoupling Order. As such, utilities would continue to fund capex through capital markets and recover operational and financing costs through rate cases. Despite little change with regards to utilities' funding mechanisms, there would be specific impacts to cost categories that a change in the regulatory model (i.e., to the Outcomes-based PBR model) would bring. This includes a potential increase in administrative costs to utilities due to increased data gathering brought upon by Performance Incentive Mechanisms ("PIMs") and a potential increase in savings due to reduced rate cases. Further details regarding the impacts on costs can be found in Task 2.5.3 (Analysis of how costs differ under each regulatory model).

1.2 Conventional PBR with Light HERA

Under the Conventional PBR component of the proposed Conventional PBR with Light HERA model, utilities would continue to source funding as under the status quo and Outcomes-based PBR approach. With respect to the HERA component of the model, utilities would fund the change in the proposed regulatory model through a surcharge, separate from the revenue requirement of the utility, as enabled by the existing legal framework in the State of Hawaii. More specifically, under the provisions of Chapter 269 of the Hawaii Revised Statutes ("HRS"), utilities would be able to create a surcharge to be collected to fund the entity elected to be HERA.

1.3 Outcomes-based PBR with DSPP and IGO

Similar to the earlier alternative regulatory models, the utility funding mechanisms under the Outcomes-based PBR component of the Hybrid model would be no different than under the status quo. Nonetheless, under the DSPP model, utilities would be able to fund investments related to the adoption of grid platform infrastructure and technology through including these investments in the utilities' revenue requirements. In other words, these costs would ultimately appear on the end-consumers' monthly electricity bills. That being said, the DSPP model does introduce other revenue streams for utilities aside from the traditional revenues that come with the sale of electricity. For instance, as DSPPs, utilities would also be able to earn Platform Service Revenues ("PSRs") for providing market-facing platform activities for market participants. Further, under the IGO component of the Hybrid model, additional costs would be recovered similarly to Independent System Operators ("ISOs"). Like ISOs such as ISO New England, New York ISO, and PJM Interconnection, the IGO could fund its operating expenditure ("opex") and capex through a combination of private financing and fees to market participants (which would trickle down to retail customer bills).

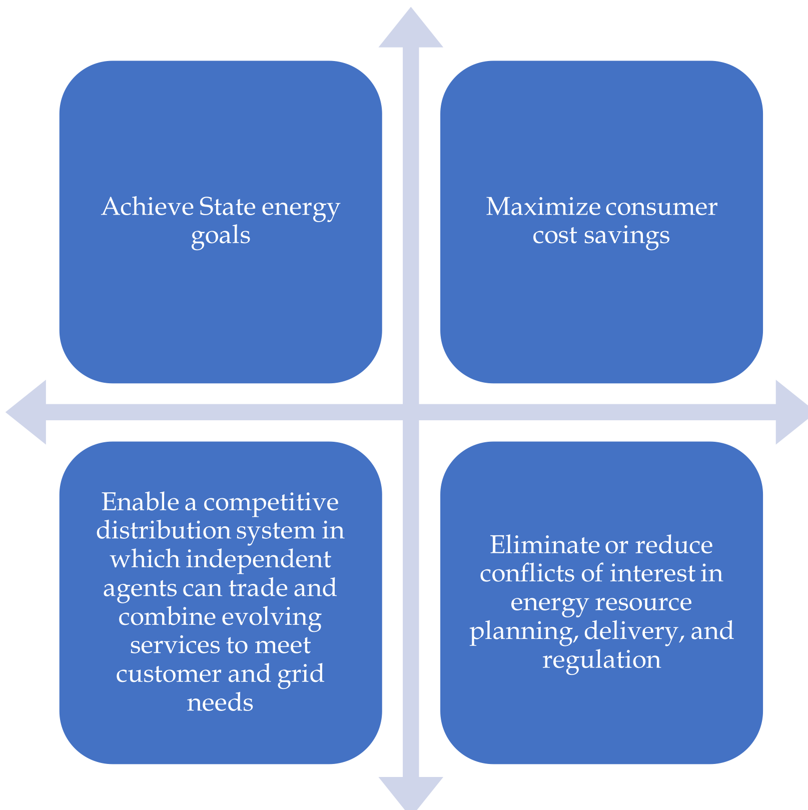
Figure 1. Summary of regulatory models' respective funding and recovery mechanisms

Regulatory model		Funding mechanism
1) Status quo		• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
2) Outcomes-based PBR		• Private financing (short- and long-term debt and equity) • Major Project Interim Recovery adjustment mechanism • Recovery through rates from customers (revenue requirements)
3) Conventional PBR with Light HERA	**Conventional PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	HERA	• Surcharge to customers (separate from revenue requirements)
4) Hybrid	**Outcomes-based PBR**	• Private financing (short- and long-term debt and equity) • Recovery through rates from customers (revenue requirements)
	DSPP	• Recovery through rates from customers (revenue requirements) and earnings from market-facing platform activities for market participants
	IGO	• Recovery through fees to market participants

2 Introduction and scope

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT") was directed by the state legislature to commission a study to evaluate the costs and benefits of various electric utility ownership models and regulatory models to support the state in achieving its energy goals. LEI, through a competitive sealed proposals procurement,[1] was contracted to perform this study.[2]

Figure 2. State's key criteria for evaluating the models



Source: Scope of Services under Contract No. 65595

The goal of the project is to assess the different utility ownership and regulatory models for Hawaii and the ability of each model to achieve the State's key criteria[3] listed in Figure 2. The study will also help in understanding the long-term operational and financial costs and benefits of electric utility ownership and regulatory models to serve each county of the state. In addition, it will also aid in identifying the process to be followed to form such ownership and regulatory

[1] Request for Proposals for a Study to Evaluate Utility Ownership and Regulatory Models for Hawaii (RFP17-020-SID).

[2] Hawaii Contract No. 65595 between DBEDT and LEI signed on March 23, 2017.

[3] House Bill No. 1700 Relating to the State Budget.

models, as well as determining whether such models would create synergies in terms of increasing local control over energy sources serving each county; ability to diversify energy resources; economic development; reducing greenhouse gas emissions; increasing system reliability and power quality; and lowering costs to all consumers.[4]

This deliverable corresponds to Task 2.5.5 in the project scope of work. It identifies potential funding mechanisms for three alternative regulatory models to the status quo, which are Outcomes-based PBR, Conventional PBR with Light HERA, and Outcomes-based PBR with DSPP and IGO. This document also includes a brief overview of the nature of potential direct and indirect cost to customers for each model.

[4] Hawaii Contract No. 65595. Scope of Services.

3 Major cost components of electric utilities

As introduced in the Task 1.4.2 report, major cost components for an electric utility are comprised of capital costs and operating and maintenance ("O&M") costs. Since utilities need to raise capital to pay for capex, these costs can be further subdivided into the utility's expenditure on purchasing or replacing assets, and the cost of financing this spending.

Capex can take many forms. For instance, the acquisition by a utility or parent company of assets from another entity needs to be financed. The purchase price would depend on a mutually agreed-upon valuation of the assets and transaction costs. Additionally, the purchase price and terms would need to be approved by the PUC. Financing the acquisition is typically dependent on financing mechanisms available to the acquiring party (which can be an IOU, cooperative, or other entity, each with different ways of raising money), and independent of the ownership structure of the former asset owners.

Capex can also accrue without a change in ownership of utility assets. For instance, through investments in:

- new electric plant infrastructure (production, transmission, or distribution);
- fuel, materials, or supplies inventory;
- various regulatory assets; or
- any other type of investment that is amortized over multiple years.

On the other hand, O&M costs are expenses for day-to-day operations of the utility and comprised of costs associated for instance to:

- the operations and maintenance of assets;
- employee compensation and benefits;
- fuel and purchased power;
- administrative expenses; or
- taxes.

O&M expenditures are not financed. These costs are passed directly on to consumers so that they are paid for on an annual basis from revenues from power sales. In a rate case, the PUC typically determines and authorizes parameters such as the total annual revenues required by the utility to cover expenses and obtain a fair return on equity, such that the revenue requirement forms the basis to determine rates. This is discussed in detail in Task 1.6.1 working paper.

Rate cases typically include allowances for working capital, in addition to the valuation, to ensure sufficient liquidity for the financing of day-to-day operations. Working capital refers to the difference between current assets and current reliabilities; the value represents the capital that is required for short-term items (e.g., cash, inventories) needed on a day-to-day basis. The calculation is based on the average lag between accounts payable, or expenditures (e.g., employee compensation, fuel costs, maintenance, etc.), and accounts receivable, or the number of sales billed to customers (i.e., payments that have yet to be made).

State of Hawaii Public Utilities Commission funding mechanisms

The State of Hawaii Public Utilities Commission ("PUC") was established in 1913 to "*protect the public interest by overseeing and regulating public utilities*," ensuring that the service provided is reliable and the rates charged are reasonable. In Hawaii, the PUC regulates electricity, gas, telecommunications, water carriers, and motor carriers' transportation, as well as water and wastewater service entities. While the implementation of all three regulatory models, namely the Outcomes-based PBR, Conventional PBR with Light HERA, and Outcomes-based PBR with DSPP and IGO models, will affect the Hawaii PUC's costs, the funding mechanisms the Commission utilizes to recover its costs should remain the same.

For the recovery of direct expenses incurred, the Commission utilizes the Special Fund. All fees and revenues that the Hawaii PUC collects are deposited into said Special Fund, and consequently administered by the PUC itself, and used to cover all opex incurred by the PUC, as well as the Division of Consumer Advocacy ("DCA"), Department of Commerce and Consumer Affairs. The Special Fund begins with a balance of $1 million at the beginning of each year, carried over from the previous fiscal year. Any amounts above $1 million at the end of the fiscal year are transferred over to the General Fund.

Fees and revenues collected and consequently deposited into this Special Fund include Public Utility Fees; public utilities pay annual fees of 0.5% of their gross income from the previous year's business, paid semi-annually (i.e., 0.25% in July and 0.25% in December). Motor carriers, too, pay annual fees of 0.25% of their gross income in the previous year of business. Special Fund revenues also include filing fees, duplication fees, interest and penalties, and One Call Center fees.

In 2017, the Special Fund's revenues were derived from Public Utility Fees (89.79%); Motor Carrier Fees (9.13%); Hawaii Motor Carrier Interest, Penalties, and Fines (0.42%); Hawaii One Call Center Fees (0.37%); and Filing Fees and Other Revenues (0.29%). As such, the 2017 Special Fund revenues totaled approximately $19.15 million. Total 2017 direct expenditures, on the other hand, amounted to roughly $6.23 million, thereby accounting for approximately 33% of expenditures from the Special Fund. The remaining 67% of the Special Fund expenditures comprised of transfers to State agencies or the General Fund, as well as expenditures on PUC personnel.

While PUC funds its operations through market participants, the aforementioned Public Utility Fees eventually trickle down to retail electric customers. These charges are not listed as a surcharge but rather built into the revenue requirements of the utilities.

Source: State of Hawaii Public Utilities Commission. *Annual Report for Fiscal Year 2017.* <https://puc.hawaii.gov/wp-content/uploads/2017/12/PUC-Annual-Report-FY2017.pdf>; "Introduction." *State of Hawaii Public Utilities Commission.* Web. September 11, 2018. <http://puc.hawaii.gov/about/introduction/>; HECO Direct Testimonies & Exhibits Book 10

4 Status Quo

Under the status quo, utilities recover their opex or capex through a traditional Cost-of-Service ("COS") regime which has been supplemented with different mechanisms to incentivize utility performance, such as Performance Incentive Mechanisms ("PIMs"), Earning-Sharing Mechanism ("ESM"), or revenue decoupling. Details of costs under this regulatory model are provided in Task 2.5.3 (Analysis of how costs differ under each regulatory model).

The parent company of Hawaiian Electric Company ("HECO"), Hawaii Electric Light Company ("HELCO"), and Maui Electric Company ("MECO") (i.e., "the HECO Companies"), Hawaiian Electric Industries, Inc. ("HEI"), finances its capex through a combination of debt (short- and long-term) and equity (e.g., stock).[5] While no such amounts were outstanding as of December 31, 2017, HEI occasionally makes short-term loans to HECO to meet HECO's cash requirements, including funding its own loans to HELCO and MECO.

In 2017, HECO's capital structure was comprised of 42% long-term debt (net), 1% preferred stock, and 57% common stock equity.[6] According to HEI's *2017 Annual Report to Shareholders*, HECO utilizes short-term debt (e.g., commercial paper) to finance normal operations, as well as to refinance short-term debt and other temporary requirements. As mentioned above, HECO periodically borrows from HEI not only for itself but for HELCO and MECO, as well. HECO also regularly makes or takes short-term loans to and from HELCO and MECO; these cross-utility loans are eliminated in the consolidation of HECO's financial statements. Furthermore, to fund capital improvement projects or to repay short-term loans used to fund capital improvement projects, the utilities "*utilize long-term debt, borrowings of the proceeds of special purpose revenue bonds…issued by the Department of Budget and Finance of the State of Hawaii[,] and the issuance of privately placed unsecured senior notes bearing taxable interest.*"[7] HECO has a $200 million line of credit facility.

Further, utilities in Hawaii fund their opex and financing costs for specific capex through rate cases; put differently, these costs are passed to the ratepayers such that the utilities can pay for their costs annually through revenues from energy sales. Unless otherwise agreed to, electric utilities in Hawaii are "*required by PUC order to initiate a rate proceeding every third year (on a staggered basis)*," thereby allowing the Commission and DCA to evaluate decoupling.[8] This also allows utilities to request a level of revenue requirement such that they are able to recover their operating costs, as well as financing costs for certain capital costs (i.e., cost of plant and equipment, cost of new capital projects to ensure or improve service reliability, and the cost of new capital projects to increase renewable energy implementation). For capital project costs

---

[5] HEI. *2017 Annual Report to Shareholders.* Page 46. <https://issuu.com/heihawaii/docs/hawaiian_electric_industries_2017_a?e=9369327/59600119>

[6] Ibid, page 60.

[7] Ibid, page 60.

[8] Ibid, page 60.

beyond the Commission's cost cap, utilities can recover their costs through cost recovery mechanisms other than base rates, such as through the recently established Major Project Interim Recovery ("MPIR") adjustment mechanism, as introduced on April 27, 2017, through the 2017 Decoupling Order.[9]

The MPIR mechanism allows projects with capex net of customer contributions over $2.5 million, including renewable energy, energy efficiency, utility-scale generation, grid modernization, and other projects to recover revenues for net costs "*placed in service between general rate cases wherein cost recovery is limited by a revenue cap and is not provided by other effective recovery mechanisms.*"[10] The MPIR mechanism also allows for the recovery of approved accrued revenues upon the specified project's in-service date to be collected from ratepayers through the annual Revenue Balancing Account ("RBA") tariff.[11] Conversely, those capital projects that are not eligible for cost recovery through said MPIR mechanism would instead be included in the Rate Adjustment Mechanism ("RAM") and thus be subject to the RAM cap in the interim; utilities would then be able to request the recovery of said capital costs through its base rates in the next rate case.[12]

Through the 2017 Decoupling Order, the PUC also establishes the recovery of fuel and purchased energy expenses to be done through a modified energy cost adjustment mechanism as opposed to through base rates; the PUC will also "*consider adopting processes to periodically reset fuel efficiency measures embedded in the energy cost adjustment mechanism to account for changes in the generating system.*"[13]

---

[9] Ibid, page 121.

[10] Ibid, page 122.

[11] The Revenue Balancing Account Rate Adjustment is a charge or credit approved by the Public Utilities Commission under a new method of setting electric rates called decoupling, which supports Hawaiian Electric's clean energy efforts. (Source: "Understanding Your Bill." *HEI*. Web. September 19, 2018. <https://www.hawaiianelectric.com/billing-and-payment/understanding-your-bill/understanding-elements-of-your-bill>)

[12] HEI. *2017 Annual Report to Shareholders*. Page 122. <https://issuu.com/heihawaii/docs/hawaiian_electric_industries_2017_a?e=9369327/59600119>

[13] Ibid, page 122.

5 Outcomes-based PBR

Under the Outcomes-based PBR model, like the United Kingdom's ("UK") Revenue = Incentives + Innovation + Outputs ("RIIO") model, the focus is on incentivizing specific outcomes by providing utilities flexibility in producing the results. Further details on the Outcomes-based PBR model can be found in Task 2.1.1 (Review of potential regulatory models that could be applied in Hawaii), Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals), and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration).

All costs related to the implementation of the Outcomes-based PBR model would be borne by the utility, and therefore be passed as operational spending. While the method for setting the level of revenue requirements and rates, as described in the previously referenced Tasks, is different under the Outcomes-based PBR regulatory model than it is under the status quo, the funding mechanism by which utilities recover their opex or capex would not change. Indeed, utilities would still turn to the capital markets to fund capex and recover opex and financing costs through rates.

Some of the cost categories that are impacted by the change in the regulatory model include, for instance, an increase in administrative costs for the utility to gather and file data required to support expanded performance incentive mechanisms ("PIM"), or increased costs related to the PBR rate-setting proceedings. Conversely, the longer regulatory periods of five (5) years that come with an Outcomes-based PBR model (relative to the status-quo) would lead to fewer rate cases, and thus, increased savings for both the utilities and the PUC. Details of costs under this regulatory model are provided in Task 2.5.3 (Analysis of how costs differ under reach regulatory model).

Changes in costs to the State of Hawaii Public Utilities Commission

With the implementation of the new regulatory model, the means by which the Hawaii PUC funds its costs should remain the same (see *State of Hawaii Public Utilities Commission funding mechanisms* box in Section 3). Nonetheless, the Commission may see an increase or decrease in costs, as follows:

- The PUC may need to hire consultant(s) to provide expertise pertaining to the implementation of the proposed regulatory models. This may lead to an increase in costs.
- The implementation of models that increase oversight of the PUC, such as the Outcomes-based PBR variant, may necessitate increased administrative costs. For instance, expanded PIMs may require increased coordination and thus increased staffing to assess utilities' targets and achievements at the end of the regulatory period, resulting in overall higher costs.
- Nonetheless, with the implementation of PBR models, the regulatory period would likely be lengthened from the status quo (from three to five years), thereby requiring fewer rate cases. This would lead to increased savings for both the PUC and the utilities.

6 Conventional PBR with Light HERA

The Conventional PBR with Light HERA model will employ the indexing formula of the Conventional PBR alongside a light adoption of the HERA model; this combined model is discussed in further detail in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals) and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration).

The implementation of the Conventional PBR with Light HERA may induce changes in costs to the utility, as well. Unlike the Outcomes-based PBR model, the Conventional PBR model would maintain the current regulatory period of three (3) years, fewer PIMs (relative to the Outcomes-based PBR), and no requirement to file capital and asset management plans, thereby decreasing coordination and administrative costs on the utilities' end (relative to the Outcomes-based PBR). Further details to the impact of costs under this regulatory model are discussed in Task 2.5.3 (Analysis of how costs differ under reach regulatory model). Nonetheless, the means by which costs are recovered under the Conventional PBR would be the same as that of the Outcomes-based PBR model.

Funding for the HERA entity of the proposed regulatory model, however, would be separate from the revenue requirement of the utility. HERA would be financed through imposing a surcharge to the ratepayers, as described in the State of Hawaii's existing legal framework.

6.1 Conventional PBR

While the impact of a change of regulatory model on utilities' costs may differ under the two PBR variants, costs borne by utilities would be funded in the same way under the Conventional PBR model as under the status quo and Outcomes-based PBR approaches. In other words, utilities would continue to support their opex and capex through a combination of debt (short- and long-term) and equity and recover through rate cases (see Section **Error! Reference source not found.** for further details).

6.2 Light HERA

Under the provisions of Part IX, Electric Reliability of Chapter 269, HRS ("the HERA Law"), "*[the] Act allows for the creation of a surcharge affecting users and operators of the Hawaii electric system to be collected for the purpose of maintaining system reliability.*"[14] More specifically, under HRS Chapter 269-146, the Commission is allowed to transfer the surcharge amounts collected, in its entirety or in parts, to any entity elected to be HERA. As such, said surcharges borne by users of the Hawaii electric system would aid in funding the establishment and operations of the HERA entity.

An example of a jurisdiction which has an entity similar to HERA is Texas. In particular, the Texas Reliability Entity ("Texas RE") serves as the Electric Reliability Organization ("ERO") for the State of Texas, and as such is responsible for monitoring the reliability standards within the Electric

[14] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

Reliability Council of Texas ("ERCOT") territory. Texas RE is a not-for-profit corporation which, via an agreement formed with the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC"), is responsible for the following:[15]

- "*Develop, monitor, assess, and enforce compliance with NERC Reliability Standards;*
- *Develop regional standards; [and]*
- *Assess and periodically report on the reliability and adequacy of the bulk power system.*"

Furthermore, similar to Hawaii, Texas is not under FERC jurisdiction and like HERA, the Texas RE also funds its operations through a surcharge on the net load. Further details have been provided in the following text box.

Texas Reliability Entity's funding mechanisms

Texas RE is a voluntary organization with membership open to any entity that qualifies (i.e., any entity that is a user, owner, or operator in the ERCOT region bulk power system) and complies with Bylaws requirements. Those who join the Texas RE can do so at no cost; put differently, there are no membership fees involved. Instead, Texas RE sources its funding from ERO funding, as well as from funding for state obligations.

ERO funding, derived from NERC, serves as the primary funding mechanism for Texas RE. More specifically, the funding is obtained from NERC Assessments and Penalty Sanction fees. NERC sources said funding by "*[allocating] costs to end users in the United States based on net energy for load*." Based on the national aggregate net energy load in 2015, NERC indicated that its proposed total United States net funding requirement for the ERO enterprise is $0.0000389 per kWh. For 2018 for instance, the ERO funding totals $11,548,986, comprised of $11,271,986 from NERC Assessments, $275,000 from Penalty Sanctions, and $2,000 in interest. This accounts for approximately 91% of the total budget for 2018.

Texas RE also utilizes ERCOT ISO system administration fees to fund state (non-statutory) activities. Non-statutory activities include auditing market participants' compliance with ERCOT Regional Rules, reporting on non-compliance, and providing testimony and regulatory support to the Public Utilities Commission of Texas ("PUCT"). The payment of said administration fee to Texas RE is authorized by the PUCT. For 2018, Texas RE's total non-statutory budget and funding is $1,091,743, accounting for approximately 9% of the total budget.

Sources: Texas RE. *2017 Annual Report*; Texas RE. *2019 Business Plan and Budget*; FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

Similar to Texas RE, HRS Chapter 269-146 would enable utilities to collect a surcharge to recover "*appropriate and reasonable*" costs from all users of the Hawaiian electric system (i.e., ratepayers) in order to finance HERA's activities including the interconnection to the system, interconnection studies, and other analyses needed to assess the impact of infrastructure and operational systems on reliability.[16] As such, the surcharge would consequently increase ratepayers' monthly bills.

---

[15] "About Us." *Texas RE.* Web. September 18, 2018. <https://www.texasre.org/Pages/About-Us.aspx>

[16] HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery.* HI Rev Stat § 269-146 (2017).

7 Hybrid model

Another model that the Project Team is analyzing is the so-called Hybrid model, which consists of Outcomes-based PBR with DSPP and IGO, to allow Hawaii to achieve most, if not all, of the State goals. At its core, this model would rely on the Outcomes-based PBR model discussed in Section 0. The functions of an independent system operator ("ISO") and independent distribution system operator ("DSO") will be combined to form the IGO. As such, responsibilities including planning and operations, including the dispatch of generation asset together with the operation of both the transmission and distribution systems, would fall under the purview of the IGO. Lastly, under this model, utilities would act as DSPPs. The DSPPs would then be able to establish the framework for grid support services for distributed energy resources ("DERs") and other service providers. Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals) and Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration) further discuss the details of this proposed hybrid model.

To assess how the costs of implementing this Hybrid model can be funded as a whole, the Project Team has examined how the implementation of each component of the regulatory model (i.e., Outcomes-based PBR, DSPP, and IGO) can be funded.

7.1 Outcomes-based PBR

Costs borne by the utilities under the Outcomes-based PBR component of the hybrid model would be funded and recovered in the same way as under a pure Outcomes-based PBR model. In other words, utilities would continue to fund its operating and capital spending through a combination of debt (short- and long-term) and equity and recovered through rate cases (see Section **Error! Reference source not found.** for further details).

7.2 DSPP

As has been mentioned in Task 2.2.1 and Task 2.2.3, there currently are no jurisdictions that have employed the DSPP model to completion. For a utility to take on the role of a DSPP, the utility would need to adopt certain grid platform infrastructure and technologies, thereby requiring a significant investment. The costs associated with said investments would be included in the utilities' revenue requirement and would ultimately be passed onto ratepayers in their monthly bills.

However, the DSPP model provides an additional revenue stream for utilities in addition to traditional revenues associated with the sale of electricity to end users. Platform Service Revenues ("PSRs") for utilities would be earned by the utilities for providing Distributed System Platform ("DSP") services to market participants as DSPPs. Examples of services may include customer origination via an online portal, data analysis, co-branding, transaction and/or platform access fees, optimization or scheduling services that add value to DER, advertising, energy services financing, engineering services for microgrids, and enhanced power quality services.[17] As such, for the PSRs associated with implementing the DSPP model to be included in the rate case proceedings, ratemaking would need to be modified.

In this regard, New York's Reforming the Energy Vision ("REV") model provides a representative framework with regards to how utilities may achieve their earnings. More specifically, as per the State of New York Public Service Commission's ("NY PSC") *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, utilities have four ways of achieving earnings, as follows:[18]

1. traditional cost-of-service earnings;

2. earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit;

3. earnings from market-facing platform activities; and

4. transitional outcome-based performance measures.

According to the NY PSC, "*these additional measures are collectively intended to create a regulatory environment where utilities can create shareholder value, comparable to or superior to conventional investments, by integrating third-party solutions and capital that improve the efficiency, resiliency, and flexibility of the physical networks, reduce consumer total costs[,] and achieve the State's policy objectives.*"[19]

In the context of the proposed Hybrid model for Hawaii, the Outcomes-Based PBR mechanism would accomplish the same objectives as the tracks 1, 2, and 4 as proposed by the NY PSC:

- With regards to the first track, even in a PBR environment, the traditional COS approach is used to calculate going-in rates which allow utilities to recover opex and capex financing costs.

- Under the second track, the PBR mechanism's total expenditure ("totex") approach ensures utilities' earnings would be tied to the achievement of alternatives that enable them to reduce capex all while providing a definitive consumer benefit.

- For the fourth and last track, Outcomes-based PBR is an effective implementation of a mechanism to ensure targets mandated by State policy goals are met through incentivizing the utility to achieve these outcomes, and where utilities' earnings would be linked with near-term measures that would enable customer savings as well as the

---

[17] State of New York Public Service Commission. *Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. May 19, 2016. Page 41.

[18] Ibid, page 41.

[19] Ibid, page 2.

development of market-enabling tools.[20] In New York, for instance, this is achieved through the implementation of Earnings Adjustment Mechanisms ("EAMs") relating to peak reduction, energy efficiency, customer engagement, affordability, and interconnection.[21] However, the NY PSC's Order notes that "*over time, as PSRs become a larger component of utility revenues, the need for EAMs should diminish as utilities enable the success of markets in order to enhance their own earnings.*"[22]

The third track mentioned by the NY PSC in the REV proceeding is similar to the DSPP services envisioned in the proposed Hybrid model, where utilities would see earnings from market-facing platform activities. Increased PSRs would not only encourage utilities to allow DER providers access to their systems, but it would also aid in offsetting the required base revenues from ratepayers (i.e., the PSRs would be derived from ratepayers).[23]

The REV framework developed in New York has also enabled utilities to recover costs associated with pilot projects. One such example is Consolidated Edison's ("ConEd") Brooklyn-Queens Demand Management ("BQDM") project. Launched in 2014, the BQDM project consisted of a series of pilot programs that allowed ConEd to defer a $1.2 billion substation upgrade.[24] The NY PSC authorized ConEd to recover the costs of the approximately $200 million in investments, comprising of 52 MW of demand response investments and 17 MW of distributed resource investments, through a monthly supplemental charge on ratepayers' electric bills.[25,26] These increases on monthly electric bills are lower than those that would have allowed ConEd to recover substation upgrade costs.

7.3 IGO

As introduced in Task 2.2.1 (Preliminary and high-level evaluation of the regulatory models relative to Hawaii State's goals), the IGO represents the combined roles of the ISO and DSO. The IGO would be responsible for planning and operations, including transmission and distribution system dispatch, whereas the utilities would continue to own the transmission and distribution

---

[20] Ibid, page 12.

[21] Ibid, page 13.

[22] Ibid, page 13.

[23] Ibid, page 12 and page 50.

[24] "Straight Outta BQDM: Consolidated Edison looks to expand its non-wires approach." *Utility Dive.* July 19, 2017. Web. September 19, 2018. < https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/>

[25] Ibid

[26] "A High-Wire Act: Balancing a Modern Grid with Regulated Assets." *Yale Center for Business and the Environment.* January 9, 2018. Web. September 19, 2018. <https://cbey.yale.edu/2018/01/09/high-wire-act-balancing-modern-grid-with-regulated-assets>

assets. Nonetheless, since the role of the proposed IGO for the State of Hawaii is akin to that of ISOs in other markets, the Project Team has turned to select ISOs as a reference for their funding mechanisms.

North American ISOs, such as ISO New England ("ISO-NE"), New York ISO ("NYISO"), PJM Interconnection ("PJM"), California ISO ("CAISO"), and Midcontinent ISO ("MISO"), as not-for-profit, non-taxed entities, fund the services they provide through private financing, as well as through fees collected from wholesale market participants (i.e., load-serving entities ("LSEs"), generators, marketers) that use regional transmission services. Similarly, an IGO could recover its costs through market participants that use both regional transmission and distribution services. While ISO costs are initially recovered through LSEs and generators, they do eventually trickle down to retail customers. Put differently, the ISO costs are added to generator offers, thereby increasing the cost of supply for LSEs; LSEs then add these increased costs to their revenue requirement, thereby once again translating to slightly higher rates for the end-consumer. To demonstrate funding mechanisms that can be used in the proposed IGO model, the Project Team has examined ISO-NE, NYISO, and PJM.

ISO New England

ISO-NE funds its opex and capex costs through a combination of private financing and market participant fees. While it does not have equity or accumulated reserves, ISO-NE has a $20 million line of credit with a bank, as well as an additional $4 million line of credit in case of shortages under the ISO New England Billing Policy. ISO-NE also has two private-placement issuances of approximately $50 million in total. [27] Apart from this, ISO-NE funds the remainder of its costs, namely administrative costs and capital costs to the extent not obtained through private financing, via the federally-regulated ISO New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). More specifically, the ISO Tariff is comprised of the Self-Funding Tariff (for the recovery of ISO-NE's administrative expenses) and the Capital Funding Arrangement tariffs (for the recovery of capital acquisition costs). [28,29] These costs are eventually translated to retail consumer costs in the form of a Basic Service charge; in 2018, for instance, ISO-NE services and benefits cost approximately $1.03 per month (for an average New England residential electricity customer with a usage of 750 kilowatt-hours per month). Further details ISO-NE's debt financing and ISO Tariffs can be found in Appendix B.

New York ISO

Like ISO-NE, NYISO employs both private financing and surcharges to market participants as a funding mechanism. In particular, NYISO has access to a $50 million revolving credit facility,

[27] ISO New England. *2017 Financial Report.* Page 6.
<https://www.iso-ne.com/static-assets/documents/2018/04/2017_financial_statements.pdf>

[28] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.A Recovery of ISO Administrative Expenses.* January 1, 2017.
<https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf>

[29] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.B Capital Funding Arrangements.* January 1, 2014. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_ivb.pdf>

valid through to December 31, 2018, to fund working capital expenses.[30] The ISO also has an unsecured $125 million line of credit, also valid through to December 31, 2018, to be used for the funding of capital purchases and project development.[31] Lastly, for the replacement of the ISO's Energy Management and Business Management Systems, NYISO entered into an unsecured $30 million delayed-draw term loan in March 2016; funds can be drawn until December 31, 2018. NYISO also funds opex, additional capital requirements, and debt service costs through a surcharge imposed on NYISO market participants (i.e., Rate Schedule 1). Like ISO-NE, as well, these charges do eventually trickle down to retail customer bills but account for a small portion as part of supply charges.[32] Further details on NYISO's funding mechanisms can be found in Appendix B.

PJM Interconnection

Like the abovementioned ISOs, PJM, too, incurs short- and long-term debt to pay for its capital expenses. PJM has a $100 million revolving credit agreement with PNC bank through to March 23, 2021. As of March 1, 2018, the unsecured promissory note increased to $150 million. In terms of long-term debt, PJM has a $26.3 million loan agreement with maturity through to September 1, 2021. PJM also obtains liquid collateral from transmission customers for funding transmission system modifications; as of December 31, 2017, these amounted to approximately $94.3 million.[33] Administrative costs, on the other hand, are recovered through LSEs and generators through the Open Access Transmission Tariff ("OATT"); more specifically, PJM's cost recovery structure is comprised of the following services under OATT: Control Area Administration Service; Financial Transmission Rights Administration Service; Market Support Service; Regulation and Frequency Response Administration Service; and Capacity Resource and Obligation Management Service. Like most ISOs, the charges appear as a service charge on end-consumers' monthly bills. In the event costs are over-recovered, PJM refunds the overcollection to the market participants in the preceding quarter. In the event fees are under-recovered, PJM may utilize its approximately $14 million long-term financial reserves, previously funded by PJM members.[34] Further details about the funding mechanisms PJM utilizes can be found in Appendix B.

---

30 NYISO. *Financial Statements December 31, 2017 and 2016 (With Independent Auditors' Report Thereon)*. Page 14.

31 Ibid, page 14.

32 "Frequently Asked Questions." *NYISO.* Web. September 11, 2018. <https://home.nyiso.com/faq/>

33 Ibid.

34 "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. < https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

8 Appendix A: Scope of work to which this deliverable responds

2.5.5 Identification of funding mechanisms for each regulatory model. CONTRACTOR shall identify potential funding mechanisms of each regulatory model, including an overview of the direct and indirect cost to customers for each model.

DELIVERABLE FOR TASK 2.5.5. CONTRACTOR shall provide its conclusions and all work related to identifying funding mechanisms for each regulatory model. CONTRACTOR shall include discussions of various funding mechanisms, such as utility rates and surcharges on those rates, capital markets, potential taxes, system benefit charge, property tax, accessing capital markets. CONTRACTOR shall provide a written summary of the findings in MS Word and Power Point. CONTRACTOR shall submit deliverable for TASK 2.5.5 to the STATE for approval.

9 Appendix B: ISO funding mechanisms

9.1 ISO New England

ISO-NE funds its opex and capex through a combination of private financing and market participants. With regards to private financing, ISO-NE has neither equity nor accumulated reserves. The ISO Tariff allows the recovery of costs, including costs of debt service, and dictates the creditworthiness of the ISO. In terms of the ISO's capital requirements, ISO-NE has a $20 million line of credit provided by a bank, as well as a $4 million line of credit with a bank in the case ISO-NE is short of funding under the ISO New England Billing Policy.

Further, "*Capital Funding Arrangements of the ISO tariff is the backstop to all the ISO's borrowings in the event of any acceleration of debt repayments*" (discussed in greater detail below).[35] ISO-NE currently also has "*two private-placement, fixed-rate note issuances totaling $50 million.*"[36]

Moreover, ISO-NE funds its administrative and the remainder of its capital costs (to the extent not obtained by the ISO through private financing) through market participants (i.e., the buyers and sellers in the wholesale electricity market), through which the effects eventually trickle down to the consumers of electricity. As such, most costs (except a few) are incurred indirectly by the customers. As a not-for-profit entity, service rates are set at levels such that ISO-NE is able to recover only what it needs to operate, determined annually through their budgeting process (Figure 3).[37]

As part of their budgeting process, or Step 2, ISO-NE develops an operating budget as well as a capital budget. The operating costs include "*the administrative functions of the ISO, including costs for scheduling and administering the movement of power through, out of, or within the balancing authority area; and costs for services the ISO provides to administer the energy and reliability markets*."[38] The capital budget, on the other hand, covers the cost of capital projects.

Since ISO-NE is a not-for-profit organization, the ISO "*charges a small fee to buyers and sellers in the wholesale markets for each transaction that the ISO handles on their behalf.*"[39] To determine what the fee will be, ISO-NE operates under a federally-regulated tariff, namely the ISO New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). The ISO Tariff is a FERC approved a document that governs "*the rates, terms, and conditions for the transmission, market, and other services*

---

[35] ISO New England. *2017 Financial Report*. Page 6. <https://www.iso-ne.com/static-assets/documents/2018/04/2017_financial_statements.pdf>

[36] Ibid, page 5.

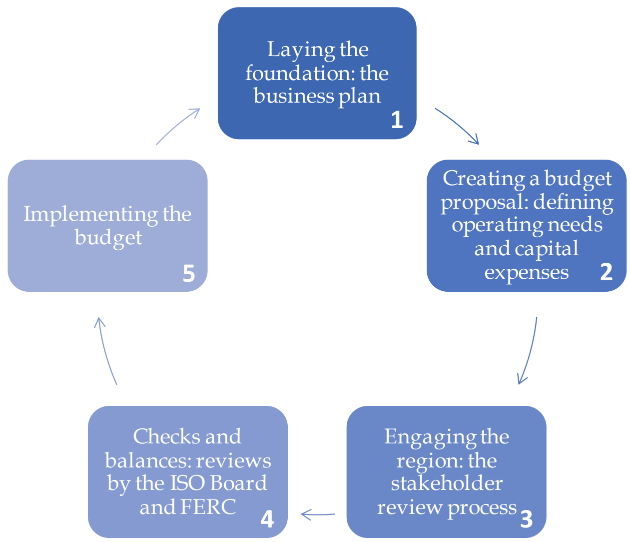
[37] "The ISO's Funding and Budgeting Process." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[38] "Transmission, Markets, and Services Tariff." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/participate/rules-procedures/tariff>

[39] "Wholesale vs. Retail Electricity Costs." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs>

ISO New England provides."[40] In particular, Section IV of the ISO Tariff discusses the various "*funding mechanisms and capital funding arrangements*" ISO-NE utilities in order to administer how the ISO acquires its funding.

Figure 3. ISO-NE's funding and budgeting process



Source: ISO New England

Self-Funding Tariff

The Self-Funding Tariff[41], or the recovery of ISO-NE's administrative expenses, describes the means by which ISO-NE recovers the costs to fulfill its administrative duties in each calendar year. These functions carried out by the ISO are comprised of:

- Scheduling, System Control, and Dispatch Service ("Scheduling Service");
- Energy Administration Service ("EAS"); and
- Reliability Administration Service ("RAS").

The **Scheduling Service** is an ancillary service that only the ISO can provide and consists of the service associated with regional-level scheduling of the "*movement of power through, out of, within, or into the New England Control Area*."[42] In that regard, all market participants using ISO-NE's

[40] "FAQs: The ISO Tariff and its Funding Mechanisms." *ISO New England*. Web. August 24, 2018. <https://www.iso-ne.com/participate/support/faq/oatt-iso-tariff#a>

[41] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.A Recovery of ISO Administrative Expenses*. January 1, 2017. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf>

[42] Ibid, page 10.

transmission service are customers of the ISO's Scheduling Service, thereby purchasing this service from the ISO. Costs are based on the activities required to provide the Scheduling Service, and thereby include (but are not limited to): the processing and implementation of regional transmission service requests, the coordination of the transmission system operations and the implementation of control actions to support said functions, billing associated with regional transmission services provided under the Tariff, transmission system planning activities to support the Scheduling Service, and associated administrative costs.[43]

Furthermore, **EAS** is the service provided by ISO-NE to administer the energy market. As such, expenses include (but are not limited to) those associated with: core operations; generation and demand dispatch associated with energy markets; energy accounting; loss determination and allocation; billing preparation; market power monitoring and mitigation; sanctions activities; operation of FTR auctions; market assessment and reports; and formulation of market rules and proposals to modify rules.[44]

Lastly, **RAS** is the service provided by ISO-NE to administer the reliability markets, "*facilitate reliability-associated transactions and arrangements*," and to provide "*reliability and informational services*."[45] RAS administrative costs include (but are not limited to) generation and demand dispatch associated with reliability markets; reliability markets accounting; billing preparation; generation emissions analysis; risk profile updates; triennial review of resource adequacy; studies and qualification of resources under the Forward Capacity Market; preparation of regional reports and load forecasts and profiles; power supply, environmental, and market reliability planning activities support; monitoring, mitigation, and assessment of market power for reliability markets; and the formulation of market rules and proposals to modify rules.[46]

Capital Funding Arrangements Tariff

The Capital Funding Arrangements Tariff, on the other hand, is utilized for ISO-NE to collect the following: [47]

1. "*the revenues necessary, to the extent not obtained by the ISO through private financing, for the acquisition of capital assets required for support of the ISO's operations;*
2. *any remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration[,] or other required repayment of private financing approved by the Commission…;*

---

[43] Ibid, page 10.

[44] Ibid, page 12.

[45] Ibid, page 15.

[46] Ibid, page 15.

[47] ISO New England. *Transmission, Markets, and Services Tariff: Section IV.B Capital Funding Arrangements.* January 1, 2014. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_ivb.pdf>

3. *the working capital amount required by the ISO in the event of termination, acceleration[,] or required repayment of private financing approved by the Commission…; and*

4. *amounts owed by the ISO in the event of termination, acceleration[,] or required repayment of Shortfall Funding Arrangement financing approved by the Commission…"*

Therefore, there are four categories of costs that comprise the Capital Funding Arrangements Tariff, namely the Capital Funding Chart ("CFC"), the Early Amortization Charge ("EAC"), the Early Amortization Working Capital Charge ("EAWCC"), and the Early Payment Shortfall Funding Charge ("EPSFC").

The **CFC** recovers the costs associated with the acquisition of capital items that have not been funded by private financing or other sources of funding. Funds are collected from Market Participant funds for the direct purchase of said capital assets, and the cost of each capital item is allocated between the three services (i.e., Scheduling Service, EAS, and RAS) depending on the extent to which the capital item is used in providing each service. The CFC is billed on a monthly basis.

The **EAC** collects from the Market Participants "*remaining unamortized costs of capital items financed by the ISO in the event of termination, acceleration[,] or required repayment of private financing, or in the case of non-amortizing private financing, payment at maturity if the ISO is unable to refinance such non-amortizing private financing.*"[48] ISO-NE provides notice to each Market Participant electronically at least 30 business days prior to when the payment is due to its lenders.

The **EAWCC** is billed to and paid by the Market Participant for funds that are needed to "*fund the working capital amount in the event of termination, acceleration[,] or required repayment of private refinancing entered into by the ISO…in support of its working capital needs.*"[49] As in the case of the EAC, ISO-NE provides notice of the "*aggregate amount of working capital (the "EAWW Amount")*" to each Market Participant electronically at least 30 business days before when the payment is due to its lenders.

Lastly, the **EPSFC** will collect funds that are required to be paid by the ISO "*in the event of termination, acceleration[,] or required repayment of the Shortfall Funding Arrangement financing entered into by the ISO in support of weekly billing under the ISO New England Billing Policy.*"[50] Also in the case of the EPSFC, ISO-NE provides notice of at least 30 business days before the payment is due to its lenders.

ISO-NE costs on the retail bill

In the end, the wholesale market cost incurred by the load server or supplier as described through the ISO Tariff above is reflected in the end-consumers bill as part of the "Basic Service" or

[48] Ibid, page 3-4.

[49] Ibid, page 4.

[50] Ibid, page 4.

"Default Service" in cents/kilowatt hour.[51] Under this charge, wholesale market energy and reliability costs are packaged with other costs from the supplier. As an example, based on a usage of 750 kilowatt-hours per month for the average New England residential electricity customer in 2018, ISO-NE services and benefits cost an average of $1.03 per month.[52]

9.2 New York ISO

Like ISO-NE, NYISO uses a combination of private financing and surcharges to market participants to fund its operations. With regards to private financing, NYISO can incur debt to pay for capital expenses, as required. NYISO has access to a $50 million revolving credit facility with an effective date of December 31, 2018, to fund its working capital expenses.[53] In 2017, NYISO had borrowings amounting to approximately $6 million under the credit agreement at an average interest rate of 2.067%; as of December 31, 2017, there were no outstanding amounts on said credit facility.[54]

In terms of long-term debt, on March 18, 2016, "*NYISO amended and restated its unsecured [$100] million line of credit facility to increase the unsecured amount to [$125] million and allow the proceeds to be drawn through December 31, 2018*."[55] Borrowings from this line of credit were used for capital purchases and development of projects. Also, NYISO entered into another unsecured $30 million delayed-draw term loan on March 18, 2016, for the replacement of the ISO's Energy Management and Business Management Systems; the proceeds can be used through to December 31, 2018.[56]

NYISO also funds its operating expenses, capital requirements, and debt service costs based on a "*strict beneficiary pays principle*."[57] Put differently, the expenses incurred by NYISO are paid through a surcharge (i.e., Rate Schedule 1) that is paid by market participants in New York's wholesale electricity markets; these costs eventually trickle down to the consumer but account for a tiny fraction of monthly electricity bills as part of supply charges.[58]

---

[51] "Wholesale vs. Retail Electricity Costs." *ISO New England*. Web. September 10, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs>

[52] "The ISO's Funding and Budgeting Process." *ISO New England*. Web. September 10, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

[53] NYISO. *Financial Statements December 31, 2017 and 2016 (With Independent Auditors' Report Thereon)*. Page 14.

[54] Ibid, page 14.

[55] Ibid, page 14.

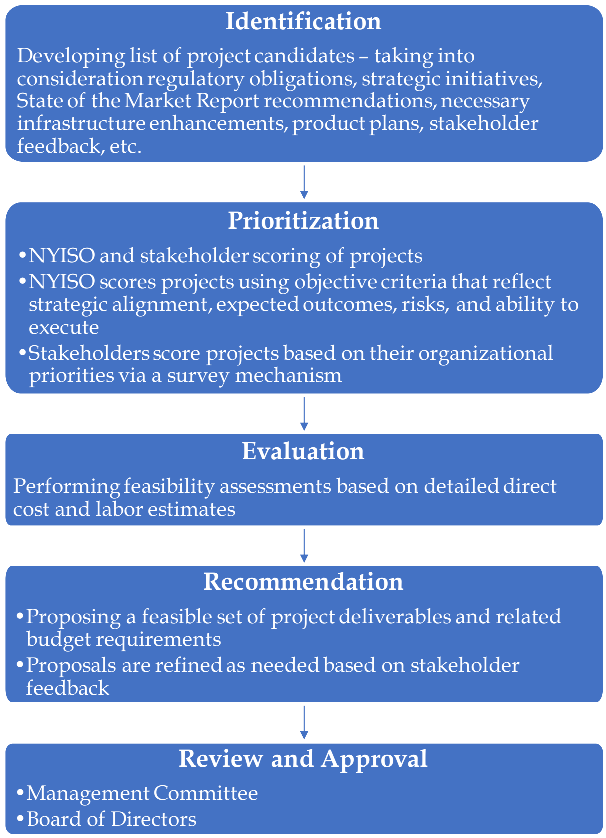
[56] Ibid, page 15.

[57] NREL. *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations.* February 2011. <https://www.nrel.gov/docs/fy11osti/49880.pdf>

[58] "Frequently Asked Questions." *NYISO*. Web. September 11, 2018. <https://home.nyiso.com/faq/>

The amount to be recovered is determined through the NYISO budget process. The Budget and Priorities Working Group projects funding in four phases (i.e., identification, prioritization, evaluation, and recommendation), as depicted in **Error! Reference source not found.**Figure 4.[59]

Figure 4. NYISO's funding and budgeting process



Source: "NYISO Budget." *NYISO*. Web. September 11, 2018.
<http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp>

As of July 1, 2018, the two FERC-approved NYISO tariffs, namely the **Open Access Transmission Tariff ("OATT")** and the **Market Administration and Control Area Services Tariff ("Services Tariff")** were "*amended to clarify NYISO's role as the single counterparty to market participant transactions in the NYISO markets.*"[60] The Services Tariff establishes the requirements applicable to NYISO's administrative functions, namely the administration of competitive markets for energy and capacity transactions, as well as the payments for suppliers of ancillary services in the

[59] "NYISO Budget." *NYISO*. Web. September 11, 2018.
<http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp>

[60] NYISO. *Independent Auditors' Report*. 2016 Financial Statements. Page 21.
<https://www.nyiso.com/public/webdocs/markets_operations/services/financial_services/Budget/Financial_Statements/2016-Annual-Financials.pdf>

administered markets and the provision of Control Area Services. This includes NYISO's services in ensuring the reliability of the power system. On the other hand, OATT sets forth the requirements for NYISO's transmission services.

Collectively known as the ISO Tariffs, these NYISO tariffs allow the ISO to recover its capital requirements, operating expenses, and debt service costs through a surcharge, Rate Schedule 1, to market participants.[61,62] NYISO earns revenues from Rate Schedule 1 once energy is scheduled and dispatched; market participants then settle said charges in the following settlement period.[63]

Rate Schedule 1

Under Rate Schedule 1, NYSIO bills each transmission customer[64] during each billing period to recover its budget costs, as well as certain other non-budged costs (e.g., NERC and Northeast Power Coordinating Council charges on a quarterly basis and FERC charges on a billing period-basis). ISO annual budgeted costs to be recovered are those associated with NYISO's operations of the transmission system as well as with the administration of the ISO Tariffs and ISO Related Agreements, including costs related to (but not limited to) the following:[65]

- Transmission system operations, administration, and support costs;
- Processing and implementation requests for transmission services (including OASIS support);
- Administration and operation of the LBMP market and other markets administered by NYISO;
- Administration of Control Area Services, Market Power Mitigation Measures, and Market Monitoring Plan;

[61] Ibid, page 21.

[62] NYISO's share of FERC fees are recovered through an independent mechanism effective January 1, 2016. Market participants are invoiced FERC fees on a monthly basis based on estimated annual fees; once NYISO receives the actual annual amount, NYISO recovers the true-up amount "*equal to the difference between the estimated fee and the actual fee.*" (Source: NYISO. *Independent Auditors' Report.* 2016 Financial Statements. Page 21. <https://www.nyiso.com/public/webdocs/markets_operations/services/financial_services/Budget/Financial_Statements/2016-Annual-Financials.pdf>)

[63] Ibid, page 21.

[64] A transmission customer is any entity that requests or receives transmission services pursuant to a Service Agreement and the terms of the ISO OATT. Market participants include transmission customers. (Source: NYISO. *NYISO MST.* Web. September 11, 2018. Page 80. <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>)

[65] NYISO. *NYISO OATT, 6.1-6.1.8 OATT Schedule 1- ISO Annual Budget Charge.* Web. September 11, 2018. <http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp>

- Reliability maintenance;
- Provision of transmission services;
- Settlement statement preparation;
- Engineering services and operations planning;
- Regulatory fees;
- Carrying costs on ISO assets, capital requirements, and debts; and
- Administrative and general expenses.

However, that "*[transmission customers] who are retail access customers being served by [an LSE] shall not pay these charges to [NYISO]; the LSE shall pay these charges.*"[66] With the amounts collected under Rate Schedule 1, NYISO has formed a working capital reserve to maintain NYISO market stability. As such, "*any [changes] to NYISO's working capital needs would be billed to market participants in future Rate Schedule 1 charges.*"[67]

9.3 PJM Interconnection

PJM Interconnection and PJM Settlement (i.e., the subsidiary of PJM responsible for member billing) are regulated by FERC. As non-stock companies, neither PJM Interconnection nor PJM Settlement can raise equity funding through stock shares; both companies also do not have any publicly issued or traded debt (e.g., bonds), but are able to incur short- and long-term debt for the recovery of capital expenses.[68] PJM administrative expenditures, on the other hand, are recovered through its members through fixed rates in PJM's OATT.

Capital expenses

PJM Interconnection is able to incur short-term and long-term debt to pay for its capital expenses. Nonetheless, if PJM's actual expenses are projected to be greater than PJM's revenues and financial reserves, PJM would need to recover costs through a rate case with FERC.

While it does not have any publicly issued or traded debt, PJM had a $100 million revolving credit agreement with PNC Bank which expired on March 23, 2018 but was granted an extension through to March 23, 2021. On November 17, 2017, PJM filed a request to extend the facility and to increase the current unsecured promissory note to $150 million. The request was approved on

[66] Ibid.

[67] NYISO. *2016 Annual Report.*

[68] "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. <https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

January 19, 2018, and the credit facility increase took effect with PNC on March 1, 2018. The "*[credit] facility is unsecured and is available to fund short-term cash obligations.*"[69] However, as of December 31, 2017, "*there were no outstanding borrowings under the revolving credit agreement.*"[70]

With regards to long-term debt, PJM's $35 million loan agreement was approved by FERC in 2009. In 2013 however, this loan was amended and refinanced at a lower interest rate for $26.3 million with the maturity extended from April 30, 2015, to September 1, 2021. As of December 31, 2017, outstanding borrowings amounted to approximately $20.7 million.[71]

In terms of costs of transmission system modifications, PJM obtains liquid collateral from transmission customers; as of December 31, 2017, PJM held deposits for study and interconnection activities amounting to approximately $94.3 million.[72]

Administrative expenses

Depending on members' activities, the administrative costs recovered via the OATT include, but are not limited to, the costs of operating the transmission system and wholesale electricity markets. Members/users include LSEs, generators, and others; approximately 75% of its costs are recovered from LSEs, whereas the remaining 25% are recovered from generation owners (20%) and financial marketers/traders (5%).[73]

More specifically, PJM's administrative cost recovery structure is comprised of the rates specified in OATT Schedules 9-1 to 9-5, comprising of tariffs for the following services:[74]

1. **Control Area Administration Service** includes activities pertaining to maintenance of reliability, as well as the administration of the Point-to-Point Transmission Service and Network Integration Transmission Service. As such, PJM charges users of this service depending on the MWh of energy delivered (including losses) by the member on a monthly basis.

2. **Financial Transmission Rights Administration Service** includes PJM activities related to the administration of Financial Transmission Rights ("FTRs"), including FTR bilateral

[69] *PJM.* PJM 2017 Financial Report.

[70] Ibid.

[71] Ibid.

[72] Ibid.

[73] Ibid.

[74] PJM. *PJM Open Access Transmission Tariff.* September 17, 2010. <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>

trading, FTR auctions, PJM's online FTR reporting tool, and FTR analyses. PJM charges users Component 1 of the FTR Service Rate based on the total FTRs in MWh in a month, and Component 2 based on the sum of the "*number of hours in all bids to buy [FTRs] Obligations*" and "*five times the number of hours in all bids to buy [FTRs] Options"* in each month.[75] Component 1 applies to any bid submitted in the monthly, annual, or long-term FTR auction, whereas Component 2 applies to any bid submitted in the annual FTR auction and the applicable monthly FTR auction, as well.

3. **Market Support ("MS") Service** includes PJM activities related to operations of the PJM Interchange Energy Market and its relevant functions, such as "*market modeling and scheduling functions, locational marginal pricing support, and support of PJM's [Internet-based] customer transaction tools*."[76] Users of the Market Support Service are charged on a monthly basis. The charge is comprised of Component 1 of the MS Service rate, based on the total MWhs of energy delivered to load in the PJM region, the total MWhs of energy input into the transmission system by a Generation Provider, and the total MWHs of all accepted Increment Offers, Decrement Bids, and "Up-to" Congestion Transactions. Component 2 of the MS Service Rate is charged based on the number of Bid/Offer Segments submitted by each user each month.

4. **Regulation and Frequency Response Administration Service** includes activities pertaining to the administration of the Regulation, and Frequency Response Service provided to LSEs and generators. Users of said service are charged the rate on a monthly basis based on the MWhs of the user's hourly regulation objective as an LSE, as well as the MWhs of regulation scheduled from generating units.

5. **Capacity Resource and Obligation Management Service** includes activities associated with "*assuring that customers have arranged for sufficient generating capacity to meet their unforced capacity obligations under the Reliability Assurance Agreement[("RAA"),]…processing Network Integration Transmission Service*", administering the Reliability Pricing Model auctions, and administering of the RAA.[77] This service is provided to LSEs and owners of capacity resources.[78] PJM charges each LSE on a monthly basis the Capacity Resource and Obligation Management Rate based on the LSE's MW per day of the daily unforced capacity obligation; in addition to this charge, PJM also charges each entity that includes in its Fixed Resource Requirement Capacity Plan a Capacity Resource committed to serving load a Capacity Resource and Obligation Management Rate charge based on the

[75] Ibid.

[76] Ibid.

[77] Ibid.

[78] Ibid.

entity's share in MWs of unforced capacity of all capacity resources committed to serve load for the month.

If PJM over-collects said fees in relation to its actual expenditures for each quarter, PJM refunds these amounts to members in the quarter to follow. Conversely, if PJM collects fewer fees than needed to cover its actual expenditures, then PJM can utilize its long-term financial reserve of approximately $14 million, previously funded by PJM members.[79]

[79] "How Does PJM Make Money?" *PJM.* Web. September 19, 2018. < https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

10 Appendix C: List of works consulted

"About Us." *Texas RE.* Web. September 18, 2018. <https://www.texasre.org/Pages/About-Us.aspx>

"Annual Work Plan." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/corporate-governance/annual-work-plan>

"A High-Wire Act: Balancing a Modern Grid with Regulated Assets." *Yale Center for Business and the Environment.* January 9, 2018. Web. September 19, 2018. <https://cbey.yale.edu/2018/01/09/high-wire-act-balancing-modern-grid-with-regulated-assets>

"Budget." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/corporate-governance/budget/>

"FAQs: Billing Process." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/participate/support/faq/billing-process>

"FAQs: The ISO Tariff and its Funding Mechanisms." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/participate/support/faq/oatt-iso-tariff#a>

FERC. Docket No. RR16-6-000. *Order Accepting 2017 Business Plans and Budgets.* Issued October 20, 2016.

"Frequently Asked Questions." *NYISO.* Web. September 11, 2018. <https://home.nyiso.com/faq/>

HEI. *2017 Annual Report to Shareholders.* <https://issuu.com/heihawaii/docs/hawaiian_electric_industries_2017_a?e=9369327/59600119>

"How Does PJM Make Money?" *PJM*. Web. September 19, 2018. < https://learn.pjm.com/who-is-pjm/how-does-pjm-make-money.aspx>

HRS Chapter 269-146. *Hawaii electricity reliability surcharge; authorization; cost recovery. HI* Rev Stat § 269-146 (2017).

"Introduction." *State of Hawaii Public Utilities Commission*. Web. September 11, 2018. <http://puc.hawaii.gov/about/introduction/>; HECO Direct Testimonies & Exhibits Book 10

NYISO. *2016 Annual Report.*

ISO New England. *2017 Financial Report.* <https://www.iso-ne.com/static-assets/documents/2018/04/2017_financial_statements.pdf>

ISO New England. *Transmission, Markets, and Services Tariff: Section IV.A Recovery of ISO Administrative Expenses.* January 1, 2017. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf>

ISO New England. *Transmission, Markets, and Services Tariff: Section IV.B Capital Funding Arrangements.* January 1, 2014. <https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_ivb.pdf>

NREL. *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations.* February 2011. <https://www.nrel.gov/docs/fy11osti/49880.pdf>

"NYISO Budget." *NYISO.* Web. September 11, 2018. <http://www.nyiso.com/public/markets_operations/services/financial_services/budget/index.jsp>

NYISO. *Financial Statements December 31, 2017, and 2016 (With Independent Auditors' Report Thereon).*

NYISO. *Independent Auditors' Report. 2016 Financial Statements.* <https://www.nyiso.com/public/webdocs/markets_operations/services/financial_services/Budget/Financial_Statements/2016-Annual-Financials.pdf>

NYISO. *NYISO MST.* Web. September 11, 2018. Page 80. <https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf>

NYISO. *NYISO OATT, 6.1-6.1.8 OATT Schedule 1- ISO Annual Budget Charge.* September 11, 2018. <http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp>

PJM. PJM 2017 Financial Report.

PJM. *PJM Open Access Transmission Tariff.* September 17, 2010. <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>

State of Hawaii Public Utilities Commission. *Annual Report for Fiscal Year 2017.* <https://puc.hawaii.gov/wp-content/uploads/2017/12/PUC-Annual-Report-FY2017.pdf>

State of New York Public Service Commission. *Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* Order Adopting a Ratemaking and Utility Revenue Model Policy Framework. May 19, 2016.

"Straight Outta BQDM: Consolidated Edison looks to expand its non-wires approach." *Utility Dive.* July 19, 2017. Web. September 19, 2018. <https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/>.

"The ISO's Funding and Budgeting Process." *ISO New England*. Web. September 10, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/the-iso-funding-and-budgeting-process>

Texas RE. *2017 Annual Report.*

Texas RE. *2019 Business Plan and Budget.*

"Transmission, Markets, and Services Tariff." *ISO New England*. Web. August 24, 2018. <https://www.iso-ne.com/participate/rules-procedures/tariff>

"Understanding Your Bill." *HEI*. Web. September 19, 2018. <https://www.hawaiianelectric.com/billing-and-payment/understanding-your-bill/understanding-elements-of-your-bill>

"Wholesale vs. Retail Electricity Costs." *ISO New England.* Web. August 24, 2018. <https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs>