Evaluation of Utility Ownership and Regulatory Models for Hawaii

prepared for
State of Hawaii Department of Business, Economic Development & Tourism

HAWAII STATE
Energy Office
ENERGY.HAWAII.GOV

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a Limited Liability Law Company

DBEDT
STATE OF HAWAII

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List of acronyms

AFR	Annual Financial Reports
AMI	Advanced Metering Infrastructure
B-corp	Benefit corporation
Capex	Capital Expenditures
CFC	Cooperative Finance Corporation
Co-op	Cooperative
COS	Cost of Service
DBEDT	Hawaii Department of Business, Economic Development, and Tourism
DCA	Division of Consumer Affairs
DCF	Discounted Cash Flow
DER	Distributed Energy Resource
DG	Distributed Generation
DSPP	Distributed System Platform Provider
ECAC	Energy Cost Adjustment Clause
EAM	Earnings Adjustment Mechanism
EIA	Energy Information Administration
ERAC	Energy Rate Adjustment Clause
ESM	Earnings Sharing Mechanism
EV	Electric Vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission
GMP	Green Mountain Power
HECO	Hawaiian Electric Company
HELCO	Hawaii Electric Light Company
HEI	Hawaiian Electric Industries
HERA	Hawaii Electricity Reliability Administrator
HI	Hawaii
IDER	Integrated Distributed Energy Resources
IDSO	Independent Distribution System Operator
IGO	Integrated Grid Operator
IOU	Investor-Owned Utility
IPP	Independent Power Producers
IRP	Integrated Resource Plan
ISO	Independent System Operator
IT	Information Technology
ITC	Investment Tax Credit
KIUC	Kauai Island Utility Cooperative
LEI	London Economics International LLC
MECO	Maui Electric Company
NCSC	National Cooperative Services Corporation

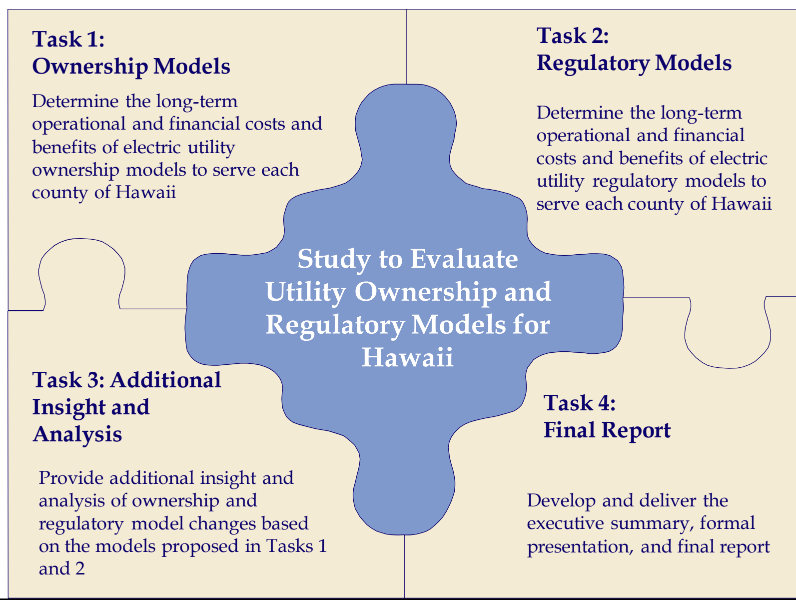
NEB	National Energy Board
NERC	North American Electric Reliability Corporation
NWA	Non-Wire Alternative
Ofgem	Office of Gas and Electricity Markets
OPA	Ontario Power Authority
Opex	Operating expenditures
PBR	Performance-based Regulation
PILOT	Payment in Lieu of Taxes
PIM	Performance Incentive Mechanism
PSIP	Power Supply Improvement Plan
PTC	Production Tax Credit
PUC	Hawaii Public Utilities Commission
RAB	Regulatory Asset Base
RAM	Revenue adjustment mechanisms
RBA	Revenue balancing accounts
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 Service
SB	Single Buyer
T&D	Transmission and Distribution
TIER	Times Interest Earned Ratio
TNB	Tenaga Nasional Berhad
Totex	Total expenditures
UK	United Kingdom
USDA	United States Department of Agriculture
WACC	Weighted average cost of capital

1 Executive summary

The Hawaii Department of Business, Economic Development and Tourism ("DBEDT"), through House Bill 1700 (Act 124), was directed by the legislature to conduct a "study to evaluate the alternative utility and regulatory models,"[1] (the "Study") and "the ability of each model to: achieve state energy goals; maximize customer cost savings; enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer needs; and eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation."[2] Through a competitive procurement process,[3] London Economics International LLC ("LEI") was awarded the contract for the conduct of the Study in March 2017.

The goal of the Study was to review and perform a thorough assessment of alternative models, laying out the pros and cons of each with respect to State policy objectives so that it could be used as a guide. As there is no single model that is best suited to achieve all objectives, the Study findings can help the legislature and stakeholders weigh alternatives as opposed to prescribe specific utility ownership and regulatory models to be implemented. The detailed discussions of analyses provided in individual task reports, which are summarized in this final report, are intended to provide enough information to assess how changes in assumptions and market conditions could impact the Study's analyses and assessments.

Figure 1. Tasks within the Study scope of work



[1] HB1700, Act 124. Task 7.

[2] Ibid.

[3] Hawaii No. RFP-17-020-SID dated September 30, 2016; Addendum No. 1 dated October 20, 2016; Addendum No. 2 dated October 24, 2016.

The scope of work is divided into four parts, namely: (i) ownership models; (ii) regulatory models; (iii) additional analyses; and (iv) final report (Figure 1). The evaluation of potential utility ownership and regulatory models was performed through separate analyses but using a similar process and methodology. The Project Team additionally examined whether changes in the rate design could provide the same benefits as changes in the ownership or regulatory models and assessed the advantages and disadvantages of managing the State's electricity sector with each county operating independently versus having a multi-county model.

1.1 Initial evaluation of ownership and regulatory models

The Project Team initially performed a review of eight utility ownership structures (Figure 2) and six regulatory models (Figure 3). Sections 4.1 and 5.1 provide a more detailed discussion of these models.

The Project Team conducted high-level analyses to evaluate each model's pros and cons, financial, legal, and operational feasibility, the achievement of the state's policy objectives, and potential stranded costs with the change in the model. It is emphasized that there can be wide variations even within ownership and regulatory structures. The Project Team has described the models in the Study in a way that encompasses the most common forms. However, each model can be further customized to meet the needs of the State of Hawaii or the individual Hawaiian Islands.

Figure 2. Utility ownership models considered in the Study

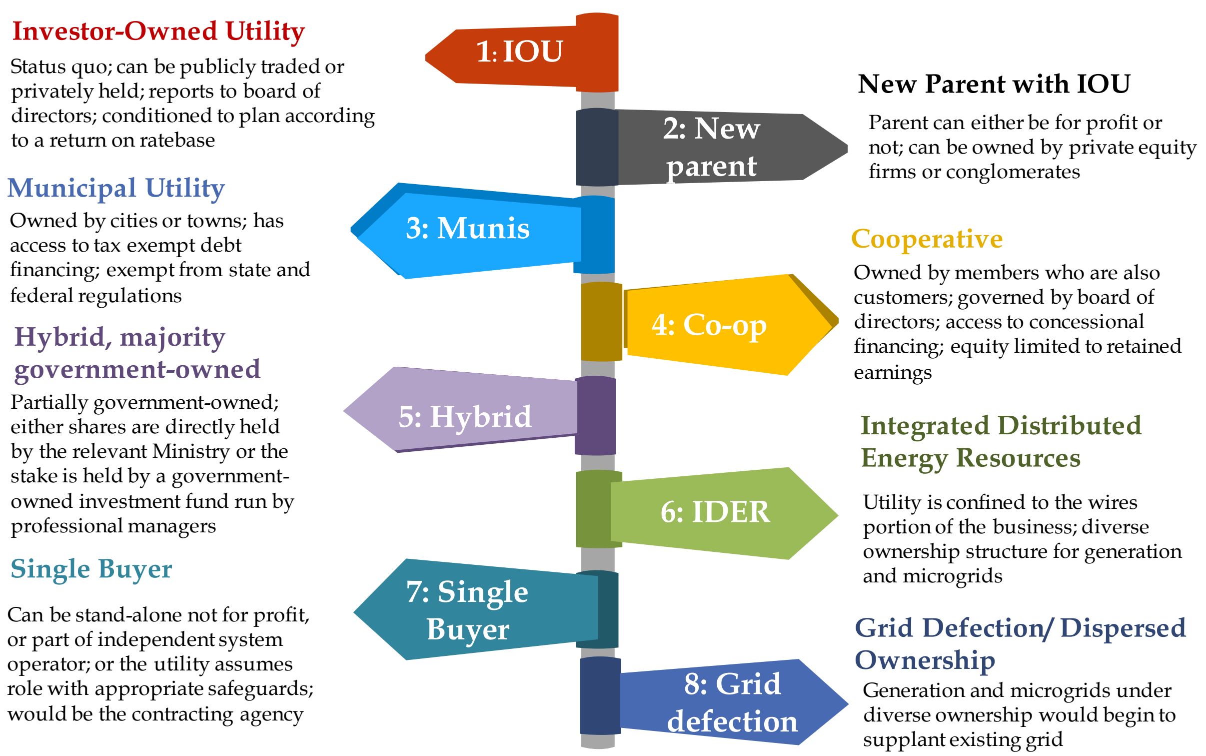
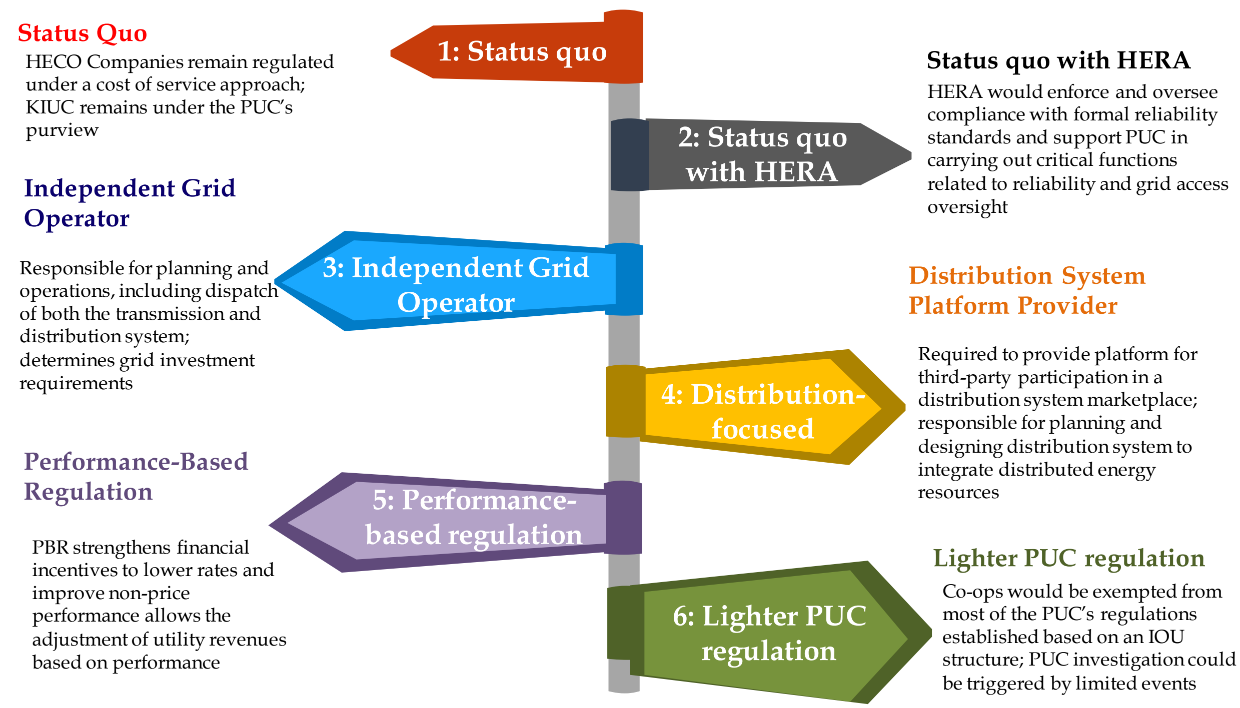


Figure 3. Regulatory models considered in the Study



Input from participants to the community dialogues was also taken into account. Three separate trips to each island (Hawaii, Maui, Lanai, Molokai, Oahu, and Kauai islands) were conducted to solicit stakeholders' inputs on the Study: June 2017 (to discuss ownership models); July 2018 (to discuss regulatory models); and November 2018 (to present the preliminary findings). The Project Team also met with various stakeholders including representatives from the utilities, the Division of Consumer Advocate, commissioners, legislators, industry players, and non-government organizations. Moreover, an e-mail address[4] was set up to collect feedback throughout the Study. All comments that were received were read, reviewed, and considered in the Study. Based on the conversations with the participants in these community discussions and one-on-one meetings, lowering electricity rates is the main (but not only) priority of stakeholders.

The Project Team selected six criteria with which to evaluate the chosen ownership and regulatory models, based on the four policy objectives established by House Bill 1700 (Act 124 of 2016). Figure 4 lists the state policy objectives and the evaluation criteria used to rank the different models.

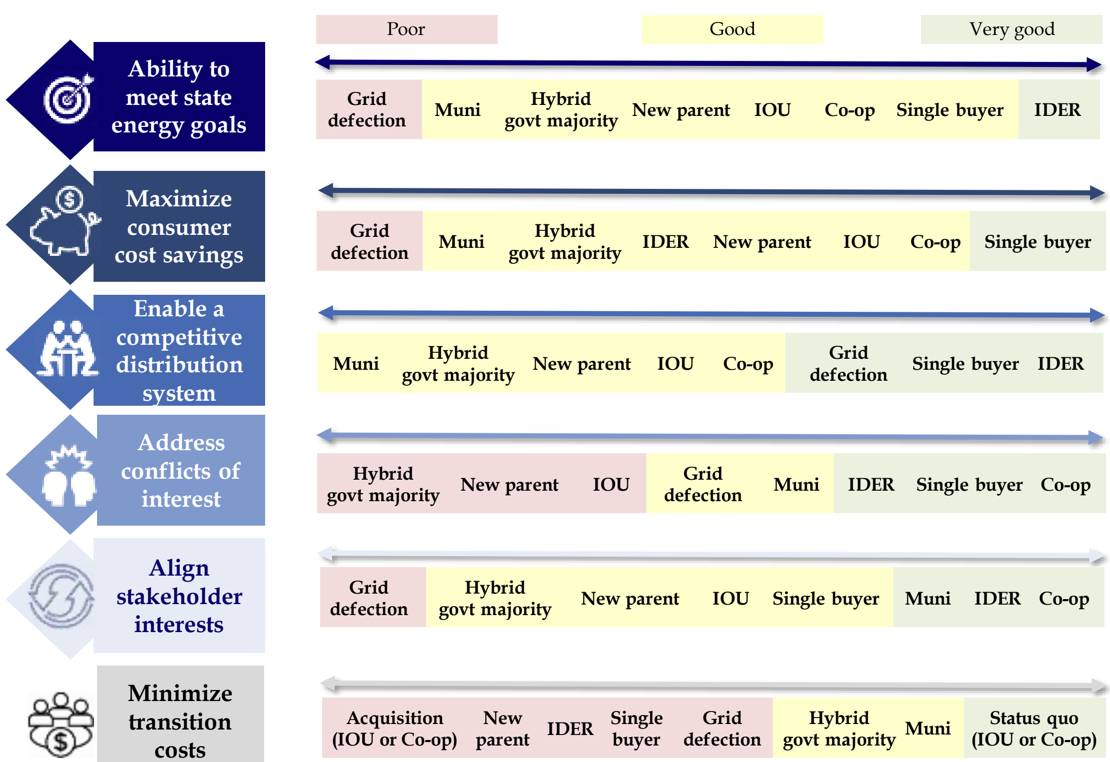
[4] DBEDT.UtilityBizModStudy@hawaii.gov

Figure 4. State policy objectives and evaluation criteria

State policy objectives	Evaluation criteria	Notes
1) Achieve State energy goals	• Ability to meet State energy goals	Assess each model's ability to meet the State energy goals
2) Maximize consumer cost savings	• Maximize consumer cost savings • Assess transition costs	Consumer costs include both ongoing costs under the model, plus any cost associated with transitioning
3) Enable a competitive distribution system	• Ability to support a competitive distribution system	Assess each model's ability to allow for competition at the distribution level
4) Eliminate or reduce conflicts of interest	• Address conflicts of interest • Align stakeholder interests	Remove the potential for conflicts of interest in utility investments, and align incentives for all stakeholders

The Project Team then performed a qualitative evaluation of the eight ownership models described previously with respect to each of the six ranking criteria, assessing how each potential ownership model would help achieve the state policy objectives absent any changes to the regulatory model. The high-level results of this assessment are presented in Figure 5 below and discussed in Section 4.4. The results were used to identify a subset of ownership models for detailed analysis, as further discussed in the next section.

Figure 5. Evaluation of ownership models relative to the ranking criteria



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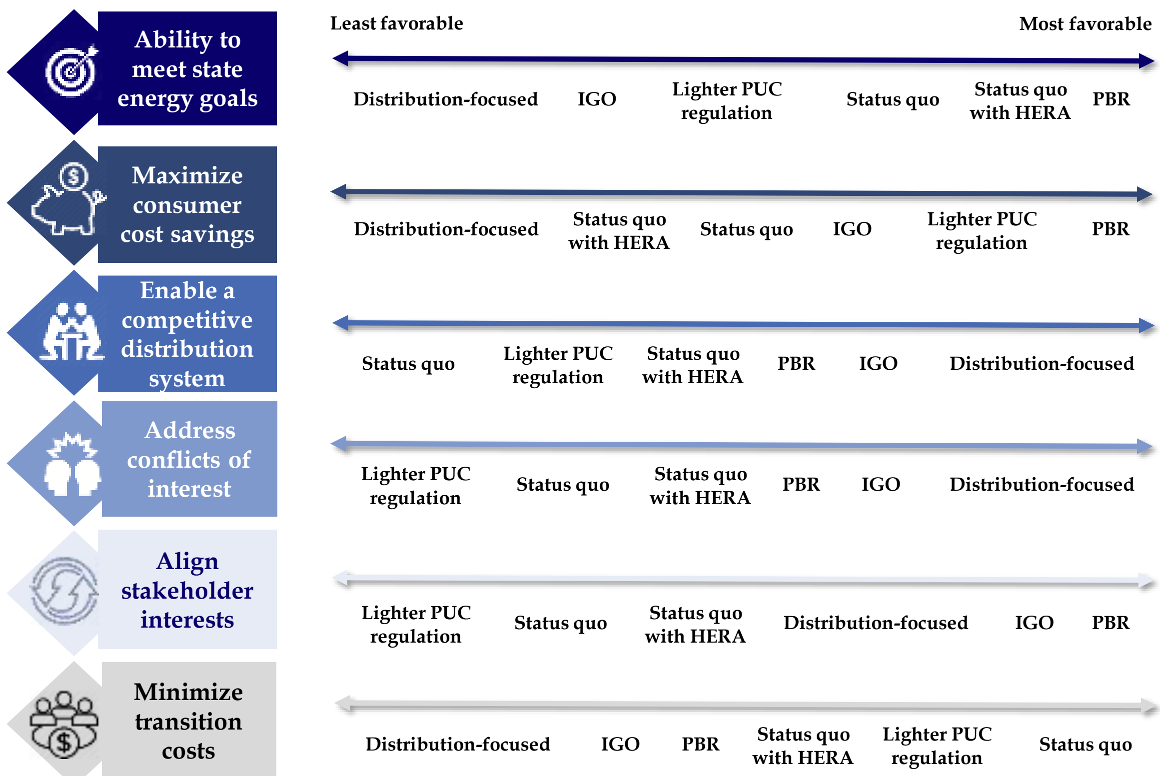
Similarly, the Project Team performed a qualitative evaluation of the six regulatory models described previously with respect to each of the six ranking criteria, again assessing how each potential regulatory model would help achieve the state policy objectives. The high-level results of this assessment are presented in Figure 6 and discussed in detail in Section 5.5. Once again, the results of the analysis were used to identify a subset of regulatory models for detailed analysis, as further discussed in the next section.

Figure 6. Evaluation of regulatory models relative to the ranking criteria



1.2 Ownership and regulatory models selected for further study

Based on the high-level analyses, comments received from the community dialogues, one-on-one meetings, and the qualitative evaluation, four ownership models were selected for further analyses in all counties:

- Investor-Owned Utility ("IOU");
- Cooperative ("co-op");
- Single Buyer ("SB") (inside the utility); and
- Single Buyer ("SB") (outside the utility).

For Hawaii, Honolulu, and Maui counties, the Project Team selected four regulatory models for additional review, namely:

- Status Quo;
- Outcomes-Based Performance-Based Regulation ("PBR");

- Conventional PBR; and
- Hybrid.

For Kauai County, the four regulatory models selected for additional review were:

- Status Quo;
- Hawaii Electricity Reliability Administrator ("HERA");
- Independent Grid Operator ("IGO"); and
- Lighter Public Utilities Commission ("PUC") Regulation.

Figure 7 provides a brief description of each of the selected ownership and regulatory models.

Figure 7. Selected utility ownership and regulatory models for further review

	Selected models for further review	
Ownership Models	**Status Quo**	HECO Companies would continue to operate as an IOU while KIUC would operate as a co-op
	Co-op	HECO Companies would move to a co-op model where its members own the utility
	Single Buyer (within the utility)	HECO Companies would create a Single Buyer unit within the utility, ring-fenced from the other business entities of the HECO Companies
	Single Buyer (outside the utility)	A Single Buyer entity would be created as a stand-alone entity outside of the utility, governed by an independent entity not affiliated with the utility
Regulatory Models	**Status Quo (COS with some PBR mechanisms for the HECO Companies)**	HECO Companies would continue to be regulated under a cost of service approach with some PBR mechanisms KIUC would continue to be under the PUC's purview
	Outcomes-based PBR	PBR focused on outcomes related to enhancing customer experience, improving utility performance, achieving public policy goals, and attaining healthy financial performance
	Conventional PBR + Light HERA	Conventional PBR enhances the current PBR mechanisms and would use an indexation formula to determine the revenue requirements of the utilities.
	Hybrid	Under the Hybrid model, the Outcomes-based PBR would be implemented first, followed by an IGO, and DSPP. Under the IGO, an independent entity would be responsible for planning and operations, including the dispatch of both the transmission and distribution system. Lastly, utilities provide distributed system platform ("DSP") services to enable third-party DER providers to create value for both customers and the system
	Lighter PUC regulation	Co-ops would be exempted from most of the PUC's regulations established based on an IOU structure; PUC investigation could be opened following certain events

The Project Team then conducted a more in-depth review of the selected models. The additional review involved determining the steps, timeline, and legal changes needed to transition to the selected models; the impact of the transition on the revenue requirements of the utilities, relative staffing needs of the Commission, ability to help Distributed Energy Resource ("DER") integration, and ultimately, average costs to the customers; and understanding the funding mechanisms to transition or establish the models. Figure 8 summarizes the timeline, legal changes, and costs required to implement alternative models in moving to another model and Sections 4.10 to 4.12 (for ownership models) and Sections 5.12 to 5.14 provide a more detailed discussion of these analyses.

Figure 8. Estimated timeline, legal/regulatory changes, and costs required to move to another model

	Models	Estimated time to move to a new model	Legal/regulatory changes required to move to a new model	Cost requirements of change in model
Ownership Models	**Status Quo (IOU)***	None	No	• None
Ownership Models	**Co-op**	24-36 months	No – burden of proof rests on the co-op to demonstrate that it can meet the laws and regulations already in place	• Acquisition costs • Regulatory costs
Ownership Models	**Single Buyer (within the utility)**	36-48 months	Yes – might require a PUC proceeding	• Set up costs for the Single Buyer (e.g., ring-fencing mechanisms) • Operating costs for the Single Buyer
Ownership Models	**Single Buyer (outside the utility)**	~48 months	Yes – legislative action is required to establish a new entity to undertake former utility planning and procurement responsibilities	• Set up costs for the Single Buyer • Operating costs for the Single Buyer
Regulatory Models	**Status Quo (COS with some PBR mechanisms)**	~21 months for PBR	No	• Regulatory costs to the utilities and the Commission
Regulatory Models	**Outcomes-based PBR**	~21 months	No - no legal changes needed because PBR falls under existing PUC authority	• Regulatory costs to the utilities and the Commission
Regulatory Models	**Conventional PBR + Light HERA**	39-45 months	No - there is existing regulation already for both PBR and HERA	• Regulatory costs to the utilities and the Commission • Costs to operate the Light HERA
Regulatory Models	**Hybrid**	81-85 months	Yes - PUC proceeding is required and legislative changes may be required to authorize a DSPP	• Costs to set up the IGO and HERA • Operating costs of IGO and DSPP • Regulatory costs (PBR)
Regulatory Models	**Lighter PUC regulation**	<12 months	Yes - the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so	• Limited regulatory costs for the transition

Based on the analyses, a regulatory or legal change is needed in most of these models, especially those that require the creation of an independent entity (SB, IGO, and DSPP). Transitioning to a different model also creates additional costs, including acquisition costs,[5] regulatory costs, and set up costs.

The Project Team's analysis results show that a change in ownership model does not necessarily address the first priority or concern of stakeholders, also a core objective of House Bill 1700 (Act 124), which is to lower electricity rates. In fact, a change in ownership model, either to the co-op model or the IOU model in the case of KIUC, would likely raise the average electricity rates relative to Status Quo in all the counties, except in Maui County. A key takeaway is that transitioning ownership models has a cost, regardless of the model, notably because of the cost for the new owner in acquiring assets from the incumbent utility. Figure 9 summarizes the impact on rates from the various ownership and regulatory models in all the counties.

Figure 9. Summary of impact on average residential rates by county and model (2018 – 2045)

	Honolulu County	Hawaii County	Maui County	Kauai County
Alternative ownership model				
Move to a co-op model	5.3%	8.2%	-1.8%	
Move to a Single Buyer within the utility model	-0.7%	0.3%	-1.3%	1.0%
Move to a Single Buyer outside the utility model	-0.8%	0.3%	-1.3%	1.0%
Move to an IOU model				6.7%
Alternative regulatory model				
Implement an Outcomes-based PBR model	-2.1%	-4.8%	-2.2%	
Implement a Conventional PBR + Light HERA model	-2.2%	-4.4%	-1.9%	
Implement Hybrid Model	-0.4%	-9.2%	-2.2%	
Move to a Lighter PUC Regulation				-0.8%
Establish a HERA model				0.0%
Establish an IGO model				-0.2%

More specifically, for Honolulu and Hawaii counties, a change to the co-op model is projected to increase average rates between 2018 and 2045 by an average of 5% and 8% per year, respectively. This increase is driven primarily by the cost of the purchase of assets of the incumbent utility, assumed to be undertaken through 100% debt financing. As a result, the co-op model is expected to lead to significantly higher debt burden, which would include interest payments. The higher costs of servicing the debt incurred for acquisition coupled with the additional financing needed for planned capital expenditure are expected to outweigh some of the cost reductions from the move to a co-op model in Honolulu and Hawaii counties. On the other hand, for Maui County, a move to the co-op model is projected to decrease electricity rates by an average of 2% per year. The projected decline in electricity rates would be primarily caused by the lower expected

[5] Related to a change in ownership model where a new owner would need to purchase the incumbent owner's assets, such as when transitioning from an IOU to a co-op or vice-versa.

acquisition cost relative to the number of customers and forecasted sales, especially compared to Hawaii County.

For Kauai County, a change to the IOU model is projected to increase average rates between 2018 and 2045 by an average of almost 7% per year. Notably, a transition to an IOU model would increase the financing costs since IOUs have a higher weighted average cost of capital than co-ops based on their cost of debt and their cost of equity.

On the other hand, the analyses showed that regulatory changes are likely to have a more significant impact when it comes to reducing electricity rates. For example, the electricity rates are projected to decrease between an average of 0.5% and 9% per year as a result of regulatory changes, depending on the county (Figure 9). This is primarily driven by strong incentives, such as those typically provided in PBR. PBR models can be designed to incentivize the utility to lower different categories of costs through targeted measures. In addition, it was observed that the benefits of the move to any of the PBR options generally outweigh the costs.

For Kauai County, the Lighter PUC Regulation model results in lowest rates (average of 0.8% per year) because of lower anticipated regulatory costs for the utility. In contrast, the HERA model would increase the electricity rates slightly because it adds incremental expenses without direct financial benefits to the ratepayers. The benefits of HERA are more oriented towards the quality and reliability of service than cost reductions. Meanwhile, the Project Team expected some efficiencies in the IGO model, especially from the transfer of grid operations to a specialized independent entity that manages both utility-scale and distribution level supply resources. However, the overhead costs associated with setting up and operating an additional entity do partially offset cost savings associated with power procurement, especially in a smaller system such as operated by the Kauai Island Utility Cooperative ("KIUC").

The potential ownership and regulatory models were also evaluated in terms of their impact on DERs, risks to the utility, staffing requirements for the Commission, and potential stranded costs. While these factors informed the selection of the highest rated ownership and regulatory models, the financial impacts discussed above must also be taken into account.

1.3 Additional analyses

The Project Team also performed a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes in rate design (Section 7.1). The Project Team evaluated a range of alternative rate designs including tiered rates (inclining and declining block rates), higher fixed charges, and time-varying rates (Time-of-Use ("TOU") rates, Real-Time Pricing ("RTP"), and Critical Peak Pricing ("CPP")). Based on a high-level qualitative evaluation of these alternative rate designs, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. At the same time, rate design is inherently interlinked with ownership and regulatory models and care must be taken to ensure that changes to rate design are consistent with overall policy goals in light of the prevailing ownership and regulatory model.

Finally, the Project Team evaluated the management of the State's electricity sector with each county operating independently as compared to a multi-county model approach (Section 7.2). The single-county vs. the multi-county models were analyzed from the perspective of the utilities' management and operations, particularly with regards to how the utilities operate the electricity system from sourcing supply to dispatching resources. The analysis showed that the multi-county model is better positioned to address the State's priorities. It received a better rating in three out of five criteria, namely, the ability to meet state energy goals, maximize consumer cost savings, and enable a competitive distribution system. In contrast, the single-county model works better in addressing two of the five criteria, namely, conflicts of interest and aligning stakeholder interests. The sixth criteria, transition costs, was not within the scope of the study for assessing single versus multi-county models as it would require a detailed analysis of the costs and policy implications of interconnecting two or more of the island grids, which is outside the scope of this study.

1.4 Key takeaways

Based on the Project Team's analyses, alternative regulatory models have a greater likelihood of helping to achieve the core policy objectives of House Bill 1700 (Act 124) relative to changes in utility ownership. This conclusion is further supported given that shortcomings of the current ownership models identified in the evaluation can be offset by changes to the regulatory model. For example, the legislature passed the Ratepayer Protection Act (SB 2939) of 2018 to address capital investment bias for investor-owned utilities under the existing regulatory regime.

The Project Team incorporated assumptions for its analyses based on publicly available data and existing studies on future developments of the State's electric infrastructure. While the actual costs for a specific implementation of alternative models may vary from the chosen assumptions, the Project Team's approach was selected to leverage data and studies that have been reviewed and approved by the Public Utilities Commission ("PUC"). This report and the supporting analyses provide enough detail to gauge the impact of changes in assumptions on the assessments contained within.

The Project Team concluded that a preferred outcome for the evolution of Hawaii State's utility business model could include a PBR framework[6] and possibly integrate alternative regulatory structures complementary to PBR. These alternative regulatory structures could be incorporated following the initial implementation of a PBR framework in Hawaii State, with decisions on whether, and how, to incorporate them being informed by developments in other jurisdictions which are currently exploring those concepts.

This Report is a summary of the analyses conducted for more than 40 underlying tasks and reports, which contain more background and additional details. These underlying reports are available on the Hawaii State Energy Office website.[7]

[6] Subject of ongoing Docket No. 2018-0088 at the PUC and a statutory requirement as mandated by the Ratepayer Protection Act (SB 2939) of 2018

[7] https://energy.hawaii.gov/

2 About the Study

DBEDT, through House Bill 1700 (Act 124 of 2016), was directed by the legislature to conduct a "study to evaluate the alternative utility and regulatory models,"[8] (the "Study") and "the ability of each model to:

1. achieve state energy goals;
2. maximize customer 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."[9,10]

Through a competitive procurement process,[11] LEI was awarded a contract to conduct the Study in March 2017. LEI undertook this Study in collaboration with Meister Consultants Group (A Cadmus Company) and Yamamoto Caliboso LLLC (collectively, the "Project Team"). The project kick-off was held in May 2017.

2.1 Process

The Study was divided into five major phases, as illustrated in Figure 10. The first phase of the Study involved the examination of existing electricity assets owned by utilities (e.g., generation, transmission, and distribution facilities) and how needs might evolve based on the utilities' plans.

Figure 10. Key Phases in the Study

The second phase focused on the review of potential utility ownership models. Several possible models for Hawaii were considered such as traditional utility-centric models [for example, IOU, co-op, municipal ("muni")], and hybrid ownership (where the State government has a majority share). Furthermore, given that technological change in the electricity sector is enabling new potential ownership arrangements, Single Buyer ("SB"), Integrated Distributed Energy Resource

[8] HB1700, Act 124. Task 7.

[9] Ibid.

[10] These are considered the goals of the legislation that directed this Study.

[11] Hawaii No. RFP-17-020-SID dated September 30, 2016; Addendum No. 1 dated October 20, 2016; Addendum No. 2 dated October 24, 2016.

(“IDER”) operator, and grid defection models were also included in the Study. These models are discussed in detail in Task 1.1.1. (*Introduction of ownership models*).

The Project Team then conducted high-level assessments on eight (8) potential utility ownership models. These evaluations considered each model’s advantages and disadvantages, similarities and differences, and how the transition to another model would impact each segment of the electricity value chain. For example, the analysis looked into whether the move would require divestment of generation or wires assets. Moreover, the utility ownership models were evaluated quantitatively to see how they relate to the key policy objectives of House Bill 1700 (Act 124 of 2016), which include achievement of state energy goals, maximization of consumer cost savings, enabling a competitive distribution system, and elimination or reduction of conflicts of interest. Also, the Project Team performed a high-level assessment of the financial, technical, and legal feasibility of transitioning to each model. Lastly, the potential for stranded costs resulting from the change in ownership was assessed. Stranded costs represent the costs that a utility was allowed to recover through regulated rates but whose recovery may be impeded or prevented as a jurisdiction transitions from a regulated regime to a competitive, deregulated environment.

Furthermore, the Study entailed extensive community engagement on all the islands studied to solicit the views of stakeholders periodically throughout the project. A total of seven community outreach events on utility ownership models were conducted in October 2017 on Hawaii, Maui, Lanai, Molokai, Oahu, and Kauai islands. Moreover, the Project Team presented an overview of the Study during the VERGE Conferences in Honolulu on June 20, 2017, and June 12, 2018, where a total of approximately 100 participants attended each session. In addition to the community outreach activities, about 60 one-on-one meetings with various stakeholders were conducted to solicit their input on the different models. During the Study, the Project Team met with utilities, government, non-profit, and other stakeholders from across the State. Figure 11 lists the approaches conducted to reaching the stakeholders, and Section 8 lists the parties that were met throughout the process.

Using a set of criteria tied to the policy objectives of House Bill 1700 (Act 124 of 2016), the Project Team ranked the models and undertook further analyses on the top three most beneficial models in addition to the status quo (IOU in all counties except Kauai where the utility is a co-op). These selected models include IOU, co-op, SB within the utility, and SB outside of the utility for the ownership models. The analyses performed included the identification of steps, timeline, and costs required to change from the current model to an alternative model as well as legal changes necessary to implement the proposed model. The additional review also involved assessing how each model could impact the PUC and the Division of Consumer Affairs (“DCA”) staffing, DER integration, utilities’ revenue requirements, and average rates paid by consumers. To determine the projected revenue requirements and electricity rates through 2045, the Project Team created a revenue requirement model for each of the four models and four counties, resulting in a total of 16 revenue requirement models. Furthermore, the Project Team identified the funding mechanisms to support the transition and operations of these different ownership models. Task 1.2.5 (*Ranking process and rationale for the recommendation of three feasible utility ownership models*) discusses the criteria used as well as the ranking while Tasks 1.3 to 1.6 provide the results of the additional review.

Phase 3, which involved the review of regulatory models, followed the same process as in Phase 2. Several possible models for Hawaii were considered such as the Status Quo but with increased oversight through the establishment of the HERA model, the establishment of an independent grid operator ("IGO"), a distribution-focused model, PBR, or lighter PUC regulation for electric co-ops.

Figure 11. Approach for reaching out to the stakeholders

Approach to reaching the stakeholders

1. **Presented in two Verge Conferences (June 2017 and June 2018)**
   - 100 attendees each session
2. **Held a community outreach for ownership models (October 2017)**
   - 141 participants
3. **Conducted one-on-one meetings in-person and over the phone (June 2017 – December 2018)**
   - 61 meetings
4. **Community outreach for regulatory models (June 2018)**
   - 75 participants
5. **Received emails or written comments (June 2017 – December 2018)**
   - 25 emails
6. **Organized a Core Group**
   - 2 meetings
7. **Presented the preliminary results (November 2018)**
   - 100++ participants

Core Working Group

- DBEDT
- SEO
- PUC
- HECO
- HELCO
- MECO
- KIUC
- Consumer Advocate
- HCEI Advisory Board Member
- County Energy Coordinators

Public Group

- County Economic Development Boards
- State legislators
- Private Sector
- Non-profit/community leaders
- Academia
- US Department of Defense
- Department of Hawaiian Homelands

Task 2.1.1 (*Ranking process and rationale for the recommendation of three feasible utility ownership models*) provides a more detailed discussion of the different regulatory models.

The Project Team conducted the same high-level analyses on the selected regulatory models as those that were performed on the various ownership models. The project team also presented these regulatory models over eight community outreach events conducted in June 2018, soliciting input and feedback from stakeholders. A total of 216 persons participated in these community outreach activities.

Using the criteria developed to address the policy objectives set by House Bill 1700 (Act 124 of 2016), the Project Team ranked the regulatory models and conducted a further review of those that rated highly. These shortlisted regulatory models for Hawaii, Maui and Oahu counties include the Outcomes-based PBR, Conventional PBR (with Light HERA), and a Hybrid model combining the Outcomes-based PBR, IGO, and distribution-focused models. In the case of Kauai County, the Project Team selected the HERA model, IGO, and lighter PUC regulation.

The Project Team then performed in-depth analyses on these high-ranked regulatory models to determine the impact of the regulatory change on the utilities' revenue requirements, cash flows, and average electricity rates as well as its effects on DER deployment and staffing needs of the PUC. Similar to the ownership model assessment, the Project Team created a revenue requirements model for each regulatory structure option for each county to derive the revenue requirements and electricity rates through 2045. A total of 12 revenue requirements models were prepared to evaluate the regulatory models. In addition, the Project Team identified the potential funding mechanisms to support the transition and operations of these regulatory models.

Under Phase 4, additional analyses were carried out which included: (i) a high-level assessment of whether the benefits of ownership and regulatory model changes could be achieved through changes to Hawaii's existing rate design; and (ii) the advantages and disadvantages of each county operating independently as compared to collectively as a part of a multi-county model.

The final report was drafted summarizing the results of the various analyses performed in all the phases. The Project Team also revisited the islands in November 2018 to present the preliminary results of the Study. Comments from the participants were solicited, reviewed, considered, and reflected in this Final Report.

2.2 Data sources

The Project Team's analytical work used data and information from relevant statutes, PUC Decisions, and Orders, as well as reports from the utilities themselves. The Project Team also collaborated extensively with the utilities, requesting specific data (if available) to supplement publicly available information. The following literature was reviewed to inform the analyses:

- Utility filings and PUC Orders under Hawaiian Electric Company's ("HECO") rate case (Docket No. 2016-0328), Hawaii Electric Light Company's ("HELCO") rate case (Docket No. 2015-0170), Maui Electric Company's ("MECO") rate case (Docket No. 2017-0150), and Kauai Island Utility Cooperative's ("KIUC") rate case (Docket No. 2009-0050);
- HECO Companies' projections for capital expenditures, resource plans, fuel prices, and load growth in the Power Supply Improvement Plan ("PSIP") report;
- HECO Companies' grid modernization strategy – Modernizing Hawaii's Grid for Our Customers ("Grid Modernization Report");
- KIUC Depreciation Study;
- KIUC 2017 Capital Improvements Program for Five Years;
- The utilities' Annual Financial Reports ("AFR") filed with the PUC;
- KIUC annual reports;
- KIUC Audited Financial Statements;
- DBEDT 2017 State of Hawaii Data Book; and

- DBEDT Economic Forecasts – Population and Economic Projections for the State of Hawaii to 2040.

The Project Team also reviewed external resources to inform assumptions on transitions to different ownership or regulatory models. This included reports and data from widely cited industry resources such as National Renewable Energy Laboratory, Lazard, and the Energy Information Agency, as well as regulatory filings for relevant models in jurisdictions such as Alberta, Ontario, Malaysia, New York, Texas, and the UK. A list of all the resources reviewed is in Section 11. This Final Report and the other reports completed for this Study include citations of and references to all sources consulted.

2.3 Reports included in the study

This final report is the culmination of 23 months of work (June 2017 to March 2019). The Project Team completed more than 40 tasks (as listed below), and all reports for these tasks are available on the Hawaii State Energy Office website.[12] This Final Report is essentially a summary of all these reports, so references to those individual reports, which contain more detailed analyses and documentation, are included.

1) Task 1.1.1 – Introduction of ownership models and asset identification
2) Task 1.1.2 – Maps for service areas of each county
3) Task 1.1.3 – Assessment of existing generation, transmission, and distribution infrastructure
4) Task 1.1.4 – High-level assessment of future needs for generation, transmission, and distribution infrastructure
5) Task 1.1.5 – High-level identification of system improvements planned for installation in the next five years and proposed improvements needed until 2045
6) Task 1.1.6 - Identification of estimated stranded costs for each ownership model
7) Task 1.2.1 - Comparison of ownership models and how they relate to the State's key factors
8) Task 1.2.2 - Empirical research and data that support the qualitative assessment of ownership models in Task 1.2.1
9) Task 1.2.3 - Summary and conclusions on the technical, financial, and legal feasibility of each ownership model
10) Task 1.2.4 – Outreach Plan and documentation of results from public outreach in each island served by an electric utility
11) Task 1.2.5 - Ranking process and rationale for the recommendation of three feasible utility ownership models

[12] https://energy.hawaii.gov/

12) Task 1.3.1 - Identification of various steps, timeline, and requirements (including costs and regulatory approvals) of the change from the current ownership model to new models
13) Task 1.3.2 - Identification of legal changes that are needed in implementing the proposed utility legal framework options
14) Task 1.3.3 - Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option
15) Task 1.3.4 - Assessment of how each ownership model impacts staffing of State agencies and stakeholders
16) Task 1.4.1 - Assessment of substantive estimate of book value for existing facilities that would need to be acquired to ensure the provision of electrical services in each county
17) Task 1.4.2 - Economic evaluation of ownership and operation of each ownership model
18) Task 1.4.3 - Assessment of management structure and staffing plan needs under each ownership model, including an assessment on the oversight management and staffing needs for Public Utilities Commission and Consumer Advocate
19) Task 1.5.1 - Estimated potential of each model to increase distributed energy resources, demand response programs, system security, reliability, resiliency, and RPS requirements through 2045
20) Task 1.5.2 - Annual load and customer projections until 2045
21) Task 1.6.1 - Overview of the differences in how revenue requirement is calculated under each ownership model
22) Task 1.6.2 - Analysis of how each ownership model would affect cash flows
23) Task 1.6.3 - Estimated revenue requirements under each ownership model until 2045
24) Task 1.6.4 - Matrix comparing system average retail rates for an average residential, commercial, and industrial customer under each ownership model up to 2045
25) Task 1.6.5 - Qualitative assessment of financing options for each ownership model
26) Task 2.1.1 - Summary comparison of Regulatory Models from Hawaii's perspective, including a graphical depiction of each regulatory model and comparison
27) Task 2.1.2 - Comparative review of regulatory models, including a high-level process assessment
28) Task 2.2.1 – High-level evaluation of the regulatory models relative to the State's goals
29) Task 2.2.2 - Assessment of current markets under each regulatory model, including a case study, analysis, and conclusions
30) Task 2.2.3 - High-level assessment of the technical, financial, and legal feasibility of each regulatory model
31) Task 2.2.4 - Summary analysis and conclusions related to estimating stranded costs for each regulatory model
32) Task 2.2.5 - Outreach Plan and documentation of results of public outreach in each island currently served by an electric utility

33) Task 2.2.6 - Identification of and recommendation for the three most beneficial regulatory models for further consideration

34) Task 2.3.1 - Identification of steps, costs, and projected timelines of the change from the current regulatory model to the recommended regulatory models

35) Task 2.3.2 - Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models

36) Task 2.3.3 - Identification and assessment of the impact of known or potential financial and operational risks to different stakeholders (ratepayers, utility shareholders, taxpayers) under each regulatory model

37) Task 2.3.4 - Assessment of how each regulatory model could impact state agencies and stakeholders such as the Public Utilities Commission and the Consumer Advocate (similar to analysis conducted in Task 1.3.4)

38) Task 2.4.1 - Estimated potential of each model to increase distributed energy resources, demand response, system security, reliability, resilience and meet Hawaii's RPS milestones up to 2045

39) Task 2.5.1 - Estimated annual revenue requirement of each of the remaining recommended regulatory models, including major costs by category; graphical representation comparing the three regulatory model outcomes

40) Task 2.5.2 - Assessment of system average retail rates for an average residential, commercial, and industrial customer in each regulatory model up to 2045

41) 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

42) Task 2.5.4 - Analysis of any issue that could impact the valuation of an electric utility in the regulatory model and identify key risks in utility valuations

43) Task 2.5.5 - Identification of funding mechanisms for each regulatory model

44) Task 3.1.1 - Assessing whether benefits of changes of ownership and/or regulatory model could be accomplished through changes in rate design

45) Task 3.1.2 - Assessing how changes in rate design compares to regulatory and ownership model changes considering overall market conditions

46) 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

2.4 Caveats

While the list of utility ownership structures and regulatory models reviewed in this Study is not exhaustive, the Project Team believes it is representative of both existing and emerging alternatives. Moreover, as there can be wide variations within each model type, the Project Team described them in a way that encompasses the most common forms. Nevertheless, each can be further customized to meet the needs of the state of Hawaii or the individual Hawaiian Islands.

While the Project Team has taken all reasonable care to ensure that the analyses are complete, the electricity market in Hawaii is highly dynamic. Thus, certain recent developments may not be included in the analyses. For instance, some of the analyses conducted in this report were performed in 2017 and 2018 so those very recent developments related to PBR, such as the PUC Staff Proposal on the recommended regulatory outcomes (which was issued on February 7, 2019), are not reflected in this report.

Also, the analyses in this Study were not intended to be comprehensive, nor can they account for all circumstances in the future. There can be substantial variation between assumptions used and actual market outcomes. No results provided in the analyses should be taken as a promise or guarantee as to the occurrence of any future events. However, this report is intended to provide sufficient detail to inform the assessment of future events or changes in assumptions on the conclusions reached in the study.

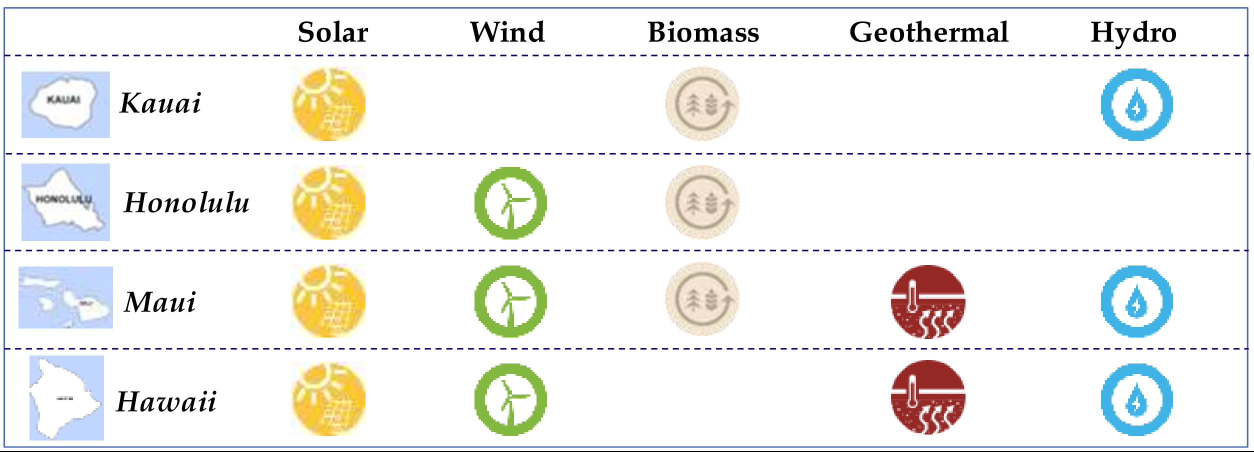
Lastly, it is important to keep the time horizon in mind when discussing each model. While the Project Team evaluated the different models relative to the Status Quo at the time this Study was conducted, the relative costs and benefits of each model may change over the nearly 30-year time horizon between the present and 2045.

3 Overview of Hawaii's electricity market

The Project Team considered the uniqueness of the State of Hawaii as well as each county in the analyses of the Study. Unlike states on the US mainland, Hawaii is comprised of islands and therefore relies heavily on imports, including oil, which tends to increase electricity prices as well as the cost of other imported consumer products. Each island's electric grid is independent, as there are no interconnections between islands. Furthermore, the state is vulnerable to various kinds of natural disasters, so resilient infrastructure is needed. It is also home to the largest concentration of US military bases in the country, so reliable electricity is essential.

Hawaii is the first state with a legislative goal of achieving 100% renewable energy. On June 8, 2015, the State passed Act 97 Session Laws of Hawaii 2015 which amended section 269-92 Hawaii Revised Statutes (proposed as House Bill 623) to increase its 2020 renewable portfolio standards ("RPS") target to 30%, maintain the 2030 RPS target at 40%, add a 2040 RPS target of 70%, and add a 2045 RPS target of 100%. The law applies to all electric utilities that sell electricity for consumption in the state and sets interim targets for net electricity sales.[13]

Figure 12. Renewable resources in each county



Each island is different and has its distinctive characteristics, resources, and challenges. For instance, the City and County of Honolulu represents the state's load center, with an annual demand that is more than twice the aggregated demand in the other three counties in 2017.[14] The County of Hawaii has a socio-economic disadvantage compared to the other counties because its income per capita was the lowest among the four counties (almost 30% lower than that of the City and County of Honolulu).[15] The County of Maui includes the three islands of Maui, Molokai, and Lanai, while the other three counties all consist of a single island that is served by an electric

[13] Affiliated electric utilities can aggregate their renewable portfolio to achieve the targets.

[14] DBEDT. *2017 State of Hawaii Data Book: Task 17 – Energy and Science*. Page 17.10.

[15] DBEDT. *2017 State of Hawaii Data Book: Task 13 – Income, Expenditures, and Wealth*. Page 13.12.

utility company. Kauai is the only county that is served by a co-op electric utility while the other three counties are served by an IOU.

Furthermore, the available renewable resources vary by county, so the renewable energy development potential in each is also different, as shown in Figure 12. For instance, it would be challenging to develop geothermal or hydro stations in the City and County of Honolulu while these would be more technically viable in Hawaii County (though they may or may not be politically acceptable).

3.1 Market overview

Hawaiian Electric Industries ("HEI") and KIUC are the two primary electric utilities that service the power needs of the state. HEI and its subsidiaries, including HECO, MECO, and HELCO, serve the majority of the state's electric utility customers, more specifically in the counties of Hawaii, Maui, and the City and County of Honolulu. For the purpose of this report, the subsidiaries HECO, HELCO, and MECO will be referred to as the HECO Companies, which owns these subsidiaries. KIUC serves the island of Kauai. [16]

These utilities are vertically integrated utilities, which means that their organizational structure encompasses generation, transmission, and distribution. The same entities, without significant internal separation, are also responsible for system planning, maintaining reliability, coordinating dispatch and grid operations, and ensuring that there is an adequate supply of energy, whether by providing energy and capacity itself or by contracting supply from independent power producers ("IPPs").

The total installed capacity in the state is 3,427 MW (as of August 2017). The City and County of Honolulu has the highest share of installed capacity (68% of the State's installed capacity), followed by Maui, Hawaii, and Kauai Counties respectively. For counties served by the HECO Companies, renewable generation ranged between 11% (City and County of Honolulu) and 41% (Hawaii County) of the total generation in 2017.[17] On Kauai, renewable generation represented 43% of total generation in 2017.[18]

The state's heavy dependence on oil renders it the most petroleum-dependent state in the country.[19] Although Honolulu features the largest installed solar PV capacity when including distributed solar resources, Kauai boasts the highest percentage of solar PV capacity relative to its total installed generation capacity. Honolulu is the only county that has a coal-fired plant while Hawaii County is the only county that has geothermal generation, though the geothermal plant is currently not operational due to a volcanic eruption in 2018.

[16] Hawaii State Energy Office. *Hawaii Energy Facts & Figures*. Honolulu: May 2017.

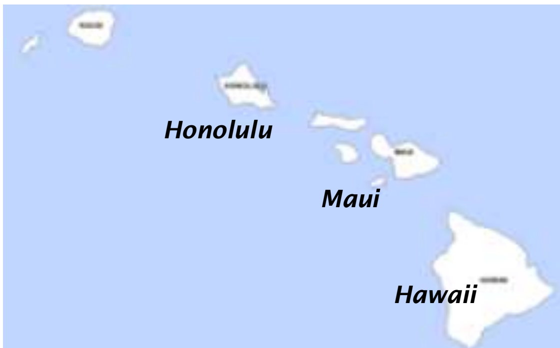
[17] <https://www.hawaiianelectric.com/clean-energy-hawaii/clean-energy-facts/about-our-fuel-mix>

[18] <http://website.kiuc.coop/renewables>

[19] EIA. *State Profile and Energy Estimates – Hawaii*. <https://www.eia.gov/state/analysis.php?sid=HI>

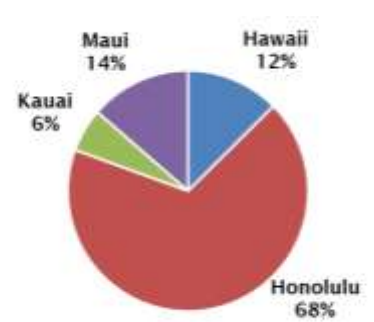
In terms of generation resource ownership, the HECO Companies dominate the generation sector, owning about 50% of the installed capacity in the State. They are the largest generation companies in Honolulu, Maui, and Hawaii counties, while KIUC is the dominant generation owner in Kauai County. There are also several IPPs in each county such as AES Corp, Tesla, Terraform Power, and Ormat Technologies, to name a few.

Figure 13. Snapshot of the Hawaii electricity market

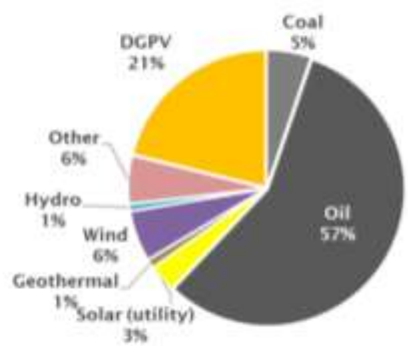


Key facts	
Installed capacity (as of August 2017)	3,427 MW
Peak demand (2017)	1,693 MW
Load growth (2012-2017)	-3.1%
Transmission lines	1,868 miles
Population (2017)	1.43 million
GDP growth (nominal, average annual growth, 2012-2017)	3.9%

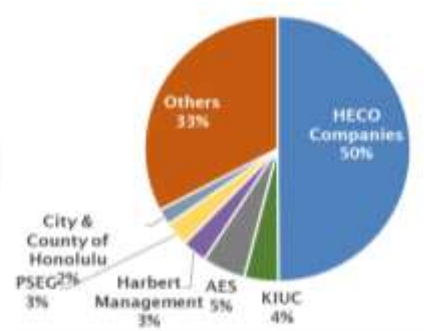
Installed capacity by county



Installed capacity by fuel type



Installed capacity by owners



Sources: HECO Companies website; KIUC website; HECO Companies' Power Supply Improvement Plans; 2017 State of Hawaii Data Book; HSEO Facts and Figures June 2018.

The electrical grids on the different islands are not interconnected to each other. The total length of transmission lines in the State of Hawaii is approximately 1,868 miles, with Hawaii County representing the largest share at about 33% of the total.[20] The transmission and distribution lines across all the four counties operate at voltages ranging from 13.8 kV – 138 kV,[21] and the operating capacity of substations ranges from 25 MVA to 320 MVA.

[20] The reported length of transmission lines is sourced from FERC Form 1 filings as of December 31, 2016.

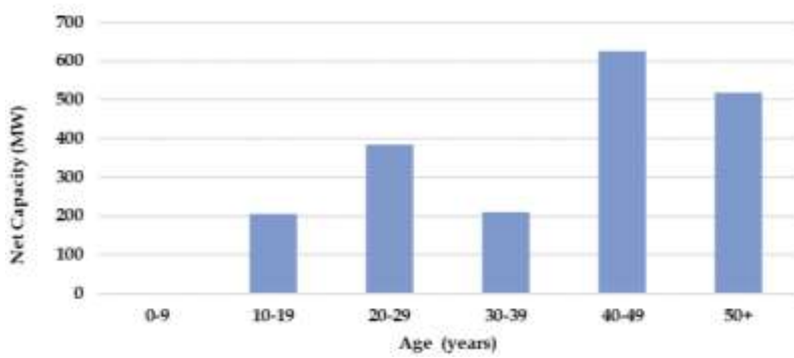
[21] Voltages of transmission lines usually vary from 69 kV to 765 kV. Source: NERC. *Glossary of Terms Used in NERC Reliability Standards*. Updated January 31, 2018.

Task 1.1.3 *(Assessment of existing generation, transmission, and distribution infrastructure in each county)* provides a more detailed discussion on the current generation, transmission, and distribution assets in the State.

Based on the review of the existing thermal generation assets in the State using documentation provided by KIUC and the HECO companies, the majority of these generation plants are old and about to reach the end of their useful life. More specifically, almost a third of the oil-fired generation capacity is between 40 to 49 years old, and more than a quarter is 50 years or older. The average age of the 1,946 MW of oil-fired generation units in Hawaii is 39.5 years old.

Almost 60% of these oil-fired plants are above the average age of retirements for oil-fired plants. Based on a sample of 148 retired plant units in the US, the average life of oil-fired plants is 39.7 years (ranging from 28 to 48 years old), depending on the technology.[22] More than 50% of the oil-fired plants in the State employ steam turbines while a quarter is combined cycle plants. The rest use either combustion gas turbines or internal combustion engines. Figure 14 shows a breakdown of the age of thermal plants in the State.

Figure 14. Age of oil-fired plants in the State



Source: HECO PSIP; KIUC website

Likewise, many of the HECO Companies' transmission and distribution ("T&D") assets are approaching the end of their useful life and need to be upgraded or replaced.[23] According to the HECO Companies, much of the installed T&D infrastructure is between 30 and 60 years old.[24] As the HECO Companies noted in the Grid Modernization Report, T&D infrastructure deteriorates due to many natural or human factors. The HECO Companies have an ongoing infrastructure replacement program to maintain the reliability of the grid to comply with the transmission reliability and security compliance standards and to avoid catastrophic events. The replacement of aging infrastructure costs more than the original installation (in real dollar terms) because of

[22] Energy Velocity database.

[23] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Page 53.

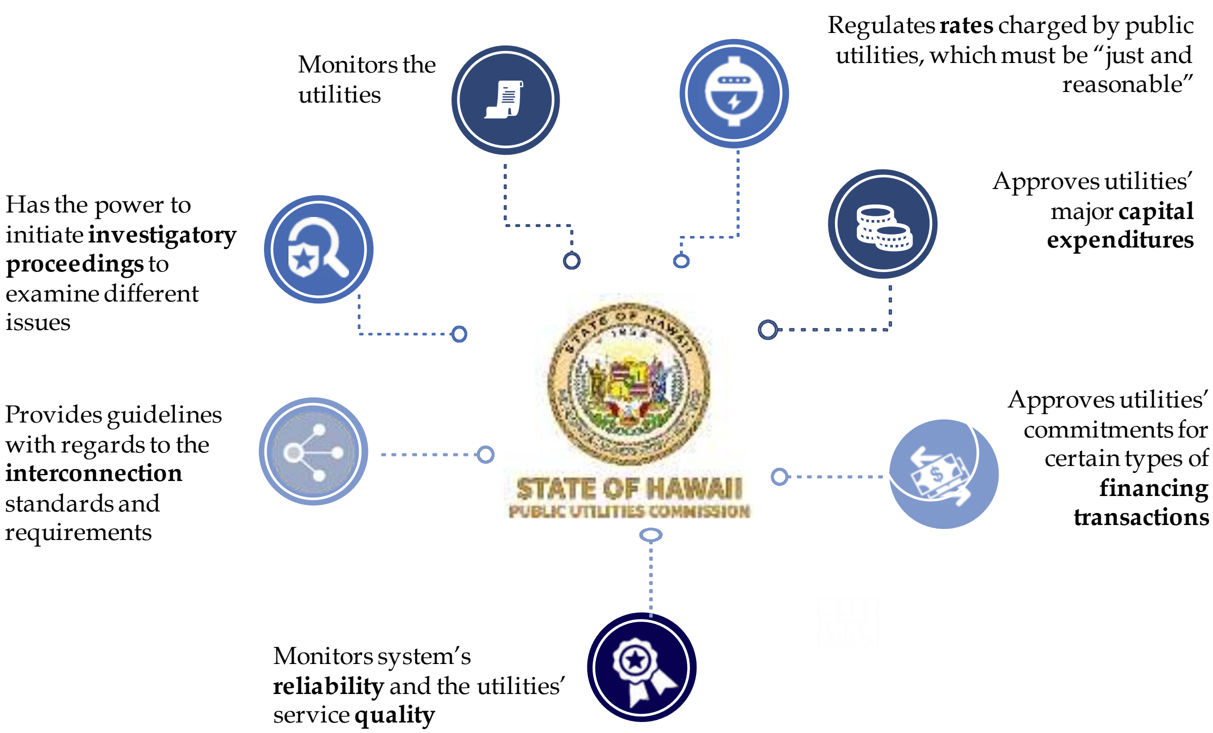
[24] HECO Companies. *Modernizing Hawaii's Grid for Our Customers*. August 2017 Draft Report. Pages 54-55.

the increased scope and complexity of replacement projects.[25] The Project Team noted HECO Companies' plans in the PSIP and the Grid Modernization Report and incorporated them in the revenue requirements model.

3.2 Institutional arrangements

The Hawaii electricity market has three main institutional public entities, namely, the State Legislature, PUC, and Hawaii State Energy Office ("HSEO"). The HECO Companies and KIUC are regulated by the PUC, whose primary mandated power and functions are shown in Figure 15.

Figure 15. PUC's mandated power and functions



Source: HRS § 269-16, HRS § 269-19, HRS §§ 269-27.5 and -27.6, HRS §§ 269-143(a), HRS § 269-6. HRS §§ 269-17 through -18, and HRS § 269-7

The PUC in Hawaii, as in other jurisdictions, exercises broad regulatory powers by utilizing its rule-making authority[26] to adopt, implement, and enforce rules and regulations that apply to electric utilities. The PUC has quasi-judicial authority in docket or case proceedings involving

[25] Ibid.

[26] *See* HRS § 269-6(a).

public utilities.[27] These proceedings are undertaken in administrative rule-making processes[28] or formal docket processes.[29] PUC is primarily mandated to "protect the public interest by overseeing and regulating public utilities to ensure that they provide reliable service at just and reasonable rates."[30]

The Hawaii State Legislature, co-equal to the executive and judicial branches of Hawaii's state government, is responsible for creating laws. The House Committee on Energy and Environmental Protection focuses on programs relating to energy resources and the development of renewable and alternative energy resources, energy conservation, environmental quality control and protection, and environmental health and other pertinent matters referred to it by the House.[31] Likewise, the Senate Committee Energy, Economic Development, and Tourism focuses on programs relating to energy resources, including the development of alternative energy resources.[32] Moreover, the Senate Committee on Commerce, Consumer Protection, and Health oversees regulations relating to public utilities and other regulated business[33] while the House Committee on Consumer Protection oversees programs relating to consumer protection and regulation of utilities.[34]

Task 2.1.2 *(Current regulatory model)* provides a more detailed discussion of the key institutional arrangements in the State.

3.3 Ratemaking process

The ratemaking process generally begins when a utility files notice of its intent to file for a general rate adjustment at least two months prior to submitting a rate application.[35] Typically, utilities request rate adjustments when costs have increased, or significant investments have been or are being made, and revenues collected no longer generate a reasonable rate of return. The difference must be sufficient in magnitude to justify the time and expense of applying for a rate increase. A

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

[28] *See* HRS § 269-6(a); HAR §§ 6-61-146 to -155.

[29] *See* HRS Chapter 269, HAR Title 6 Chapter 61-1.

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

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

[32] *Senate Committee on Energy, Economic Development, and Tourism,* Hawaii State Legislature Website, Available at https://www.capitol.hawaii.gov/committeepage.aspx?comm=TRE&year=2018 (last accessed May 14, 2018).

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

[35] HAR § 6-61-85(a).

rate case can also be initiated as required by the PUC. Each of the HECO Companies is required to file a rate case every three years,[36] while KIUC has not filed a rate case since 2010.[37]

The application describing the proposed change in rates is then submitted to the PUC along with written direct testimony justifying the request as well as supporting exhibits and work papers.[38] The Commission must determine 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.[39] The Consumer Advocate has 21 days to object to the sufficiency of the application.[40] Accordingly, the Consumer Advocate will typically file a statement of position regarding the completeness of the application while the Commission will issue an order establishing the date the completed application was filed.[41]

As required by statute, the PUC holds a public hearing for each rate case.[42] Interested persons can file motions seeking to intervene or participate in the docket, which must be filed no later than ten (10) days after the last public hearing.[43] The PUC, the Consumer Advocate, and any admitted intervenors or participants may submit information requests to build the record in the proceeding, as may be allowed and subject to any condition and limitation that may be established by the PUC.[44] Typically, the utility, Consumer Advocate, and any parties granted full intervenor status may negotiate and file a stipulation or partial stipulation for the Commission to

[36] *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.").

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

[38] *See* HAR § 6-61-87 (applies to utilities with Annual Gross Operating Revenues of $2,000,000 or more).

[39] HRS § 269-16(d); HAR § 6-61-86, -87.

[40] HRS § 269-16(d).

[41] *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).

[42] HRS § 269-16(b).

[43] HAR 6-61-57(1).

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

review if they have reached an agreement on specific issues.[45] Additional testimony and rebuttal testimony may be taken, and evidentiary hearings may be held on any unsettled issues.[46]

Generally, the PUC reviews and determines the total annual revenues required by each utility to cover projected expenses and provide an opportunity to earn a fair return on investment. 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.[47] If the PUC is unable to issue a final decision, it must issue an interim decision allowing an increase in rates, fares, and charges, if any, to which the PUC believes the utility is likely entitled.[48]

3.3.1 Ratemaking for the HECO Companies

For the investor-owned HECO Companies, as discussed below, rates are currently determined using a Cost of Service ("COS") approach supplemented by 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"). Moreover, the HECO Companies' rates include an energy cost adjustment clause ("ECAC"),[49] which adjusts rates to recover specific short-term historical fuel prices and purchased energy expenses, and a purchased power adjustment clause, which recovers certain non-energy costs associated with the power purchased from independent power producers.

Under a traditional COS approach, revenue requirements identify the expected amount of revenue the utility requires to cover its COS for a given forward twelve-month period (referred to as a "test year").[50] As shown in the formula below, the revenue requirements are comprised of the rate base multiplied by the allowed rate of return plus the sum of depreciation and amortization expenses, operating expenses, and tax expenses.[51] Under the COS approach, the operating and other expenses, as well as the cost of power, are costs that are passed on to customers and do not provide a "return on investment" to the utilities. On the other hand,

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

[46] *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).

[47] HRS § 269-16(d).

[48] HRS § 269-16(d).

[49] While it is a recent development, in Docket 2016-0328, an Energy Cost Recovery Clause ("ECRC") has replaced the ECAC for HECO, due, in part, to the Commission's guidance from Docket 2013-0141 to revise the ECAC. It is expected that HELCO and MECO will also replace their ECACs with ECRCs

[50] *See,* HAR § 6-61-87(4).

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

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 model, the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach."[52]

As shown in the revenue requirement formula below, the utility's ability to increase earnings is tied to increases in the rate base. As a result, the traditional COS approach may create an incentive for the utility to spend more on capital expenditures ("capex") 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.[53]

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

The current regulatory framework has some components associated with PBR as well. 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. The decoupling mechanism consists of an RBA and RAM.

- **Multi-Year Rate Plan ("MRP")**: MRPs permit utilities to operate for several years (typically three to five years) without general rate case.[54] The HECO Companies are on fixed three-year general rate case cycles.[55] A longer rate cycle could further incentivize utilities to reduce operating costs since they would retain the savings for a longer period before the next rate case. Consumers would then benefit from the reduced costs upon the rate reset.

- **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 which serves as the utilities' disincentive to pursue energy efficiency measures. For utilities, a revenue decoupling mechanism can be favorable, especially if they are encountering declining sales per customer. On the other hand, utilities with increasing sales per customer have a financial incentive to avoid revenue decoupling. 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

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

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

[54] Order No. 35411, at 16.

[55] Order No. 35411, at 41.

most recent rate case."[56] 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.[57]

- **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."[58] 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 and amortization expenses, and changes in costs due to significant changes in tax laws[59] or regulations.[60]
    - **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 for each year following the test year, it will be capped, and excess expenses will not be recoverable.[61]
    - **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.[62] In the case of the HECO Companies, the ESM is asymmetrical where only excess earnings (*i.e.*, where utility earnings

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

[57] *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 .

[58] *Ibid.*

[59] LEI's modeling of the revenue requirements for utility, which drives consumer rates, incorporates the recently lowered federal corporate tax rate of 21 percent.

[60] Order No. 35411, at 43.

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

[62] ESMs serve the same basic purpose as clawback mechanisms within a traditional COS framework, ensuring prices do not get too distorted or deviate too much from actual costs. In the context of indexation formulae, an exit ramps can represent an alternative (or complement) to an ESM, triggering an automatic end to the current formulae application period and initiating a COS rate review.

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. 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 be credited a 50% share. If the ROE exceeds 300 basis points or 3% of the authorized ROE, the customers will be credited a 90% share.[63]

- **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.[64] PIMs are generally put in place to ensure that any cost reductions implemented by the utility will not cause the deterioration of service quality.
    - **Service Quality (Traditional) PIMs:** Currently, the HECO Companies' rates are based in part on penalty PIMs, which are determined by the achievement of 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.[65]
    - **Targeted Energy Policy PIMs:** 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.[66]

These PBR elements are incorporated into the HECO Companies' rates using the RBA Rate Adjustment.[67] This is independent of the establishment of the HECO Companies' base rates for each rate case test year based on traditional COS methods.

3.3.2 Ratemaking for KIUC

For KIUC, a member-owned co-op, rates are determined using a debt service coverage COS approach known as the Times Interest Earned Ratio ("TIER"). Moreover, KIUC's rates include an

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[63] Order No. 35411, at 43.

[64] Order No. 35411, at 17.

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

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

[67] *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

Energy Rate Adjustment Clause ("ERAC"), which recovers specific variable fuel and purchased energy costs.

KIUC's revenue requirement calculation is based on somewhat different principles than those used for the HECO Companies. KIUC's revenue requirement target is mainly designed to meet its debt obligations rather than provide a return for shareholders. 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 revenue requirements of a co-op are set using a TIER level. 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 net income before interest and taxes by annual interest expense. Net income is essentially operating margin in the case of KIUC. The formula for the TIER level is shown below:

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

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[68] for distribution utilities, the PUC has set the current regulated TIER level for KIUC at 2.27.[69] A co-op's net margin for that year is the operating revenue remaining after operating expenses, and debt service is paid for. 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.

The following can be inferred from the formula for TIER level:

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

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

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

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

KIUC's revenue requirement is a function of the interest expense, TIER level, and operating costs:

1. Interest expense
   a) <u>Capital structure</u> helps to determine how much debt can the co-op carry. A higher debt-capital ratio increases the interest expense, thus, the revenue requirements.
   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.

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

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

2. TIER level – set by the regulator.

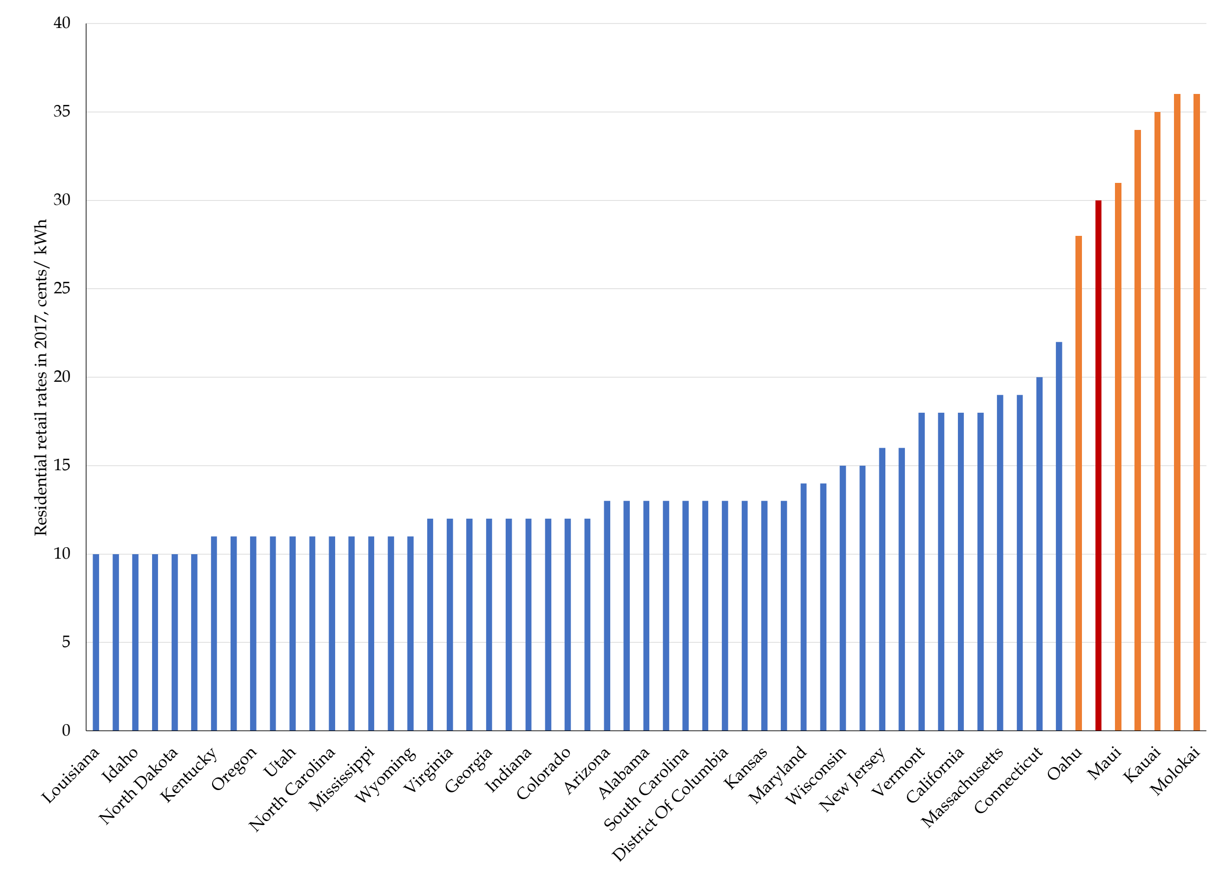
3. Operating costs – generally the same as for IOU, with the exception that tax expenses are lower for co-ops because they are exempt from federal income taxes.

Task 2.1.2 *(Current regulatory model)* provides a more detailed discussion of the current ratemaking process in Hawaii.

3.4 Electricity rates

Residential electricity customers in the State of Hawaii pay the highest rates among US states, averaging around 30 cents per kWh in 2017, which is more than twice the national average of about 13 cents per kWh (Figure 16). According to the Energy Information Administration ("EIA"), the high retail electricity rates mainly result from the State's dependence on imported petroleum combined with isolated island grids.[70]

Figure 16. Electricity rates in select US states (2017)



Source: EIA. HSEO.

[70] "State Profile and Energy Estimates: Hawaii". *EIA*. <https://www.eia.gov/state/analysis.php?sid=HI>

Residential electricity rates are lower on Oahu than on other islands. In 2017, the customers on the islands of Lanai and Molokai paid the highest average rate of 36 cents per kWh; the rate was slightly lower, approximately 34 cents per kWh, on Hawaii and Kauai islands. The average rate on Maui Island was close to the state average (30 cents per kWh) and slightly higher than the rate on Oahu (27 cents per kWh).

Most industry stakeholders and participants to the community dialogues identified high electricity rates as the most critical factor that should be considered in performing the Study.

4 Potential utility ownership models

4.1 Description of the potential ownership models

A wide range of ownership structures for utilities (or companies providing utility-like services) can be observed around the world. Furthermore, technological change is enabling the exploration of new types of ownership arrangements. For this Study, the Project Team defines a *utility* as an entity that is entitled to earn a fair return through charging regulated rates for essential service in return for assuming an obligation to serve; as per terms of the study, the Project Team focused solely on the electricity sector. Eight different ownership structures were selected based on both the scope of work provided and the assessment of various additional potential arrangements. While this list of ownership structures is not exhaustive, it is representative of both existing and emerging alternatives.

The eight potential utility ownership structures considered were:

(i) investor-owned utility – status quo in all counties except Kauai;

(ii) new parent company to IOU;

(iii) cooperative – status quo in Kauai county;

(iv) municipal;

(v) hybrid with majority government ownership in IOU;

(vi) integrated distributed energy resources operator model;

(vii) SB; and

(viii) grid defection/dispersed ownership.

Since there can be different possible implementation of various ownership models, the Project Team described them in a way that encompasses the most common forms. However, each can be further customized to meet the needs of the state of Hawaii or the individual Hawaiian Islands.

4.1.1 IOU

An IOU can be a publicly traded or privately held company. National data indicates that 189 IOUs serve 68% of US electricity customers.[71] In the case of HEI, it is traded on the New York Stock Exchange with 50.0% of shares held by institutions.[72] However, in recent years, several IOUs have been taken private by companies like Berkshire Hathaway or Macquarie; the potential for a new parent is discussed in the next section. Being publicly traded can impact management planning horizons; because public companies report earnings quarterly, some observers contend that this leads to a shorter-term management mentality.

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71 American Public Power Association. *2015-2016 Annual Directory & Statistical Report*. <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>

72 Hawaiian Electric Industries, Inc. *Institutional Ownership*. Website. <http://www.nasdaq.com/symbol/he/institutional-holdings>.

To ensure transparency and checks-and-balances, the IOU's management reports to a board of directors, which has a fiduciary duty to its shareholders. Legislators and regulators of the jurisdiction where the IOU operates set the framework for the IOU's activities based on public policy targets. Naturally, IOUs are expected to make prudent investments so that they can provide reliable service consistent with good utility practice.

IOUs in Hawaii

Hawaiian Electric Industries supplies power to approximately 95% of Hawaii's population through its electric utilities, including Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Ltd. ("MECO"), collectively known as the HECO Companies. In addition, HEI owns the financial institution American Savings Bank, F.S.B.

Number of customers (2016): 460,000 (Electric Utilities)

Total assets (2016): 5,975.43 million (Electric Utilities)

Total revenue (2016): 2,094.37 million (Electric Utilities)

Source: HEI Form 10-K. Energy Information Administration ("EIA") Schedule 4 Part A, B and C

Often, the best way for IOUs to increase profits is to pursue additional capital investments. While regulators have attempted to change incentives by redesigning the utilities' revenue requirement calculation, IOUs are conditioned to plan according to a return on rate base since profit growth is mostly linked to rate base growth.[73] As regulatory regimes evolve to incorporate a higher degree of incentives and performance-based elements, the mindsets of the utility, its customers, and its regulators need to change.

4.1.2 New parent

The implications of new ownership depend on the nature of the new parent. For example, IOUs can be owned by other IOUs, private equity firms, or conglomerates. Similarly, the new parent could also be a not-for-profit, a limited dividend, or a benefit corporation ("B corp."). It is possible that ownership by another larger publicly traded IOU may provide greater access to capital or human resources to the incumbent utility. Indeed, private equity ownership can prevent a 'quarterly mentality' by IOU's management. However, the business model of some private equity firms includes a holding period (e.g., of five to ten years) after which assets are expected to be monetized. Some firms such as Berkshire Hathaway (publicly traded but mostly a conglomerate) have assembled vast collections of IOUs across geographically diverse territories. Historically, the acquisition of a utility by a new parent has, in some instances, led to growth and innovation. This has been shown in the experience of Green Mountain Power in Vermont, the first utility to

[73] Cost of service ("COS") is the starting point for all regulatory frameworks for regulated utilities. For this paper, the Project Team assumed that the COS is constant across all the ownership models reviewed. Performance-based ratemaking ("PBR") regimes build upon COS principles, including calculation of rate base, target fair returns, and cost allocation studies.

be certified as a B corporation. However, the transaction can also lead to significant indebtedness and potential distress. The ill-fated takeover of Texas Utilities is a case in point.

Benefit corporations ("B Corp")

B Corps are for-profit corporate entities that are certified by the nonprofit B Lab to meet rigorous standards of social and environmental performance, accountability, and transparency. As a B Corp, a corporation can legally mandate social and environmental considerations other than just profit. As a result, directors possess necessary legal protection to consider the interest of all stakeholders, rather than just the shareholders who elected them.

In Hawaii, Senate Bill 298 was passed into law in 2011 as Act 209 to allow businesses in Hawaii to operate under a B Corp or sustainable business corporation structure. As of July 2017, there are seven B Corps in Hawaii, including bCause, Natural Investments LLC, Smart Sustainability Consulting, Hawaiian Legacy Hardwoods, Hawaiian Ola, Hawaiian Paddle Sports, LLC, and Sustainable Pacific Consulting.

Meanwhile, a significant number of for-profit companies are controlled by not-for-profit entities. A good example is Mountain View Power, which is an energy marketer in Alberta, Canada. Owned and managed by the Olds Institute for Community and Regional Development ("the Olds Institute"), it sells electricity and natural gas to residential, farming, and small business clients in Mountain View County. The Olds Institute is a non-profit community and economic development organization, owned by the community, and driven by volunteers.

4.1.3 Co-op

Co-ops are owned by members who are also the customers. They are incorporated under the laws of the state in which they operate. This type of ownership is not limited to utilities. For example, credit unions are often structured like co-ops. KIUC is an example of a co-op operating in Hawaii. In Hawaii County, a group of stakeholders has formed a co-op for the ultimate purpose of purchasing and operating HELCO's assets.

Electric co-ops can be structured based on key business areas: (i) generation and transmission ("G&T") co-ops; (ii) distribution co-ops; or (iii) both. G&T co-ops provide wholesale power to distribution co-ops through their generation or by purchasing power on behalf of the distribution members while distribution co-ops deliver electricity to the customers. Currently, around 42 million people in 47 states in the US are serviced by 834 distribution and 63 G&T co-ops.[74] The electric co-ops also own and maintain 2.6 million miles of distribution lines, which is the equivalent of 42% of the nation's total.[75] They generate nearly 5% of the total electricity produced and deliver 11% of the total kilowatt-hours sold in the US annually.[76]

Co-ops often enjoy autonomy and independence. They are controlled by members and governed by a board of directors, allowing transparency and democracy. In typical setups, co-op members have equal voting rights (practicing the *one member, one vote* principle). The board is expected to set major policies and procedures (which are, in turn, expected to be implemented by the management), advocate for reforms on behalf of members, approve annual operating budgets, capital expenditure budgets, and compensation plans, recruit and select a CEO, and appoint an independent auditor to perform an annual financial audit.

Co-ops have no equity other than retained earnings (revenue which has not been returned to members) but have access to concessional financing via the Rural Utilities Service ("RUS"),[77] National Rural Utilities Cooperative Finance Cooperation, and the National Cooperative Services Corporation.[78] Co-ops enjoy tax advantages such as a tax-exempt status under IRC Task 501(c) (12) (provided that 85% or more of their annual income comes from members). However, this also means that they cannot take advantage of various incentives that are provided through the tax code—examples of which include investment tax credits, accelerated depreciation, and production tax credits.

Kauai Island Utility Cooperative: an operational electric co-op in Hawaii

KIUC provides electric service on the Kauai island. On November 2002, KIUC became the first electric co-op in Hawaii when it purchased the electric utility from Citizens Communications.

Number of customers (2016): ~37,000

Total assets (2016): $381.5 million

Total revenues* (2016): $143.5 million

Note: Operating Revenues*
Source: Kauai Consolidated Financial Statements (December 31, 2016 and 2015), KIUC website. EIA Schedule 4

[74] National Rural Electric Cooperative ("NRECA"). "Electric Co-op Fact Sheet." <https://www.electric.coop/electric-cooperative-fact-sheet/>

[75] Ibid.

[76] Ibid.

[77] An agency of the US Department of Agriculture.

[78] CFC provides financing to its members for non-profit services while NCSC can lend to members, non-members, and for-profit entities as long as the activity benefits the cooperative network.

4.1.4 Municipal ownership

There are instances when cities and towns prefer to own and manage their municipal utilities ("munis"). About 15% of US electricity customers are served by 2,013 municipal utilities.[79] Many municipal utilities arose out of public works departments in various cities and towns; over time, these assumed a separate corporate identity from the cities that own them and that they serve.

Municipal ownership has both advantages and challenges. For example, municipal utilities may benefit from access to tax-exempt debt financing. They may also be tax exempt as well as exempt from various kinds of State and Federal regulations. However, by the very nature of their ownership, munis can be subject to political interference, making it difficult for them to pursue long-term strategies. Munis can be governed by the city council, a local board, or an independent board, which would impact the effectiveness of how the muni is managed. When the city council dominates the utility's management, utility rates and service policies are set by these local entities, and there are often issues related to income retention. For example, the muni may experience pressure to transfer dividends to its municipal parent. In these circumstances, muni rates may be viewed as a substitute for tax revenues. This pressure prevents them from mobilizing funds for investment. However, when there is a more independent board supervising the utility, it can operate without as much political pressure. Similar to co-ops, the only source of equity for municipal utilities is retained earnings (unless the city chooses to inject funds).

Austin Energy: A muni of similar size to HECO

Austin Energy is a large municipal utility, serving a similar number of customers to HECO - more than 461,345 customers as of 2016. It operates within the Electric Reliability Council of Texas. The operations of Austin Energy are funded entirely through energy sales and services, and the utility further supports the City of Austin and its departments through an annual transfer into the general fund of more than $100 million.

Number of customers (2016): 461,345

Total assets (2016): $4,383 million (Electric Utilities)

Total revenue (2016): $1,370 million (Electric Utilities)

Source: Velocity Suite and Austin Energy 2016 Annual Summary Report.

4.1.5 Hybrid, majority government-owned

Hybrid ownership models exist, but in almost all cases, they evolved following the involvement of private sector partners in utilities which were formerly 100% government owned. For example, a number of European utilities continue to have a high degree of state ownership despite private sector involvement. Another good example is Malaysia's largest utility, Tenaga Nasional Berhad ("TNB"), which continues to be 41.15% government owned. There are also instances when governments acquire controlling stakes in existing private utilities, which they do not intend to

[79] American Public Power Association. *2015-2016 Annual Directory & Statistical Report*. <http://www.publicpower.org/files/pdfs/uselectricutilityindustrystatistics.pdf>

expropriate. Understandably, governments follow different strategies in holding and managing investments in utilities.

In some cases, shares are held directly by the relevant Department, indicating a greater desire to use the utility as a tool for implementing government policy. In other cases, the utility stake is held by a government-owned investment fund that employs professional managers to ensure that state-owned companies are managed economically efficiently. Singapore is an example of a government that practices the latter approach.

Hybrid government-majority owned example #1: Hydro One

Hydro One is an electricity transmission and distribution utility serving the province of Ontario in Canada. As of March 31, 2017, the province of Ontario owns 70.1% of the utility.

Number of customers: 1.3 million

- Transmission: 44 local distribution companies and 87 large industrial customers connected directly to the transmission network.
- Distribution: Over 1.3 million residential and business customers

Total assets (2016): CAD $25.35 billion

Total revenues (2016): CAD $6.55 billion (includes both regulated and unregulated businesses)

Note: Exchange rate in 2016 (average): US$ 1 = CAD $1.325
Source: Hydro One Investor Fact Sheet – 2017 and Hydro One 2016 Annual Report

Hybrid government-majority owned example #2: Tenaga Nasional Berhad

TNB is the largest utility not only in Malaysia but also in the Southeast Asia region. It serves customers in Peninsular Malaysia, Sabah, and Labuan.

Number of customers: 9.2 million

Total assets (2016): RM 132,902.2 million

Total revenues (2016): RM 44,531.5 million

Note: RM = Ringgit Malaysia
Exchange rate in 2016 (average): US$ 1 = RM 4.142
Source: TNB 2016 Annual Report

State-controlled utilities are often adept in mobilizing funds primarily because government involvement leads to a 'halo effect'—investors assume that such utilities enjoy backing from the government. Hybrids are considered more advantageous by their proponents because they can raise equity on the stock market instead of relying solely on retained earnings. This is often not possible in co-ops and munis. However, government owners often impose certain limits, mainly if they are concerned about the dilution of control. This was observed in Ontario when the provincial government addressed this issue by capping the stake that any single entity can purchase. Meanwhile, the United Kingdom ("UK") has retained a so-called "golden share" after privatization. This grants the government special rights such as the ability to block a merger.

Often, hybrid entities enjoy exemptions from civil service restrictions and are somewhat insulated from political interference. However, minority shareholders may place a lower value on the utility's equity if the government is perceived to be a less profit-oriented shareholder. Public shareholders will be attentive to whether government ownership is depressing profits by influencing the utility to undertake initiatives that lack a strong commercial basis.

4.1.6 Integrated distribution energy resources ("IDER") system operator

An IDER system operator represents a new approach to utility ownership. This model does not currently exist in a fully deployed manner. However, the State of New York is moving toward implementing such a model. The utility in an IDER model is confined to the wires portion of the business and is required to provide open access to all DERs connected to it at a tariff allowing for the recovery of the utility's costs. The utility or another entity is in charge of coordinating flows across the grid. Generation would be moved to a competitive subsidiary, with appropriate consideration of stranded costs, if any. The utility may or may not provide a "standard offer" for DERs, who would be free to accept that standard offer or to contract with other customers bilaterally while paying for the use of the utility's lines. Under the IDER model, the utility would optimize the system, and in theory would have no incentive to discriminate against third-party assets, or between DERs and transmission.

IDER model example: New York's Reforming the Energy Vision ("REV")

In recognition of the rapid advancements in DER, the New York Public Service Commission ("PSC") initiated the Reforming the Energy Vision ("REV") proceeding which became a multi-pronged strategy of the state to develop a clean, resilient, and affordable energy system for all New Yorkers. It prioritizes energy efficiency and clean locally produced power. It also encourages deeper penetration of DER and engages end-users through the creation of a more local, distribution network-oriented market structure facilitated by utility as distribution system platform ("DSP") provider. The idea is to reform the traditional utility business model so that integrating DERs from third party providers is a crucial feature and to ensure that utilities are incentivized to consider DER solutions as an alternative to traditional grid investments.

The PSC directed the six large IOUs in the state to develop and file demonstration projects to test new approaches to distributed resource adoption. One of these demonstration projects is National Grid's DSP project with the Buffalo Niagara Medical Campus. In this project, National Grid is testing how it can integrate customer-owned energy resources to manage system demands. According to the implementation plan, this project is currently in "Technology Development" (Phase 2) stage of the project. The proponents are due to start the field demonstration (Phase 3) in September 2017 and they plan to complete the evaluation/report dissemination by October 2018.

Source: New York Public Service Commission, National Grid

The IDER model can lead to:

- a diversity of ownership structures for generation;
- increased potential for embedded or connected microgrids;
- increased adoption of new technologies such as blockchain to allow peer to peer transactions; and
- increased ability to optimize services across a range of technologies and grid linkages.

The model could deepen community ownership and help ensure that there would not be a dominant entity in the ownership of generation assets. IPPs, former rate base generation, and co-op or municipal generation assets could co-exist. However, such a structure would work more effectively if existing utility costs are appropriately unbundled, and open access is enforced. Nevertheless, this model has not yet been proven in practice and still needs time to evolve.

4.1.7 Single Buyer

The SB approach includes a number of variants worldwide. In some cases, the SB is established as a stand-alone, not-for-profit entity. In other cases, it is part of an Independent System Operator ("ISO"). In yet another variant, the utility itself takes on the SB role while being barred from or constrained in the ability to bid its own projects in SB procurements. An entity like the proposed HERA could fulfill this role.[80] HERA could also take on the role of system operator as envisioned in the IDER model.[81] Alternatively, the HECO Companies themselves could act as the SB, but appropriate safeguards should be in place to ensure that they are operating in a fair and transparent manner in such a scenario. This model is different from the current competitive procurement process that the HECO Companies have in place, as the SB envisioned under this model would require the establishment of a new legal entity that would be appropriately ring-fenced from other HECO Companies' business entities. Furthermore, the SB entity would assume the planning for the transmission system and resource adequacy.

[80] The Project Team notes that Act 166 authorizes the PUC to develop, adopt, and enforce reliability standards and interconnection requirements, and to contract for the performance of related duties with a party that will serve as the HERA, but does not include the SB functions mentioned here. Therefore, an amendment to the Act may be needed to include the SB and grid access oversight functions.

[81] In Singapore, the Energy Market Authority ("EMA") is the electricity and gas industry regulator. Unusually, EMA also takes the role of a Power System Operator ("PSO") and is responsible for the reliable supply of electricity to the consumers.

Single Buyer example: Tenaga Nasional Berhad

TNB is Malaysia's sole electric utility company. It was formed in 1990 as a government-owned corporation. In the 1990s, it was a vertically integrated utility, and owned the majority of generation, in addition to T&D. IPPs provided some competition in generation. TNB also conducted energy procurement from the IPPs. However, further reforms in the Malaysian Electricity Supply Industry led to the creation of the Single Buyer in 2012, a ring-fenced entity within TNB.

TNB's Grid System Operator and Single Buyer are both ring-fenced from the other business entities of TNB. Below are some of the ring-fencing measures imposed within the company.

Item	Grid System Operator ("GSO")	Single Buyer
Work area	Separate from the work areas of other divisions and units within TNB	Separate from the work areas of other divisions and units within TNB
Sharing of information	The ownership of all data in the principal operational systems used by GSO, all other data jointly by the GSO and Single buyer, and the data held in corporate or shared administrative system relating to GSO' operation or staff, shall be rest with GSO GSO shall not disclose any information that is confidential to TNB or any other party	The Single Buyer shall not disclose any information that is confidential to TNB or any other party, or information that may provide competitive advantages to any other party
Accounts	Needs to maintain a separate set of Financial Statutory Accounts, which is audited at least annually and published on the GSO's website	A separate set of Single Buyer Accounts relating to the performance of its functions as a Single Buyer should be maintained and established
Access to IT system	1) Only GSO staff can access systems that are only used by the GSO; 2) 2) shared systems are partitioned so that staff of other divisions only have information that they require in their performance and that won't provide them with competitive advantages; 3) 3) a record is maintained of the date and time that each information item is accessed and/or changed by each user of GSO's IT system.	Other users of the IT system cannot access confidential information held by the Single Buyer
Compliance report	Prepare a statement of compliance, and the GSO shall identify a full-time "Compliance Officer" who manages the compliance arrangements	Prepare a statement of compliance, issue guidelines, and provide supporting information to justify compliance

Source: Tenaga Nasional Berhad website, Electricity Tariff Regulation Implementation Guidelines

Generation ownership under the SB approach could also be diverse as in the IDER model. If the SB is a stand-alone, not-for-profit entity or an ISO, the SB itself does not own generation or wires assets; it is merely a contracting agency. However, what differs here is the need for all grid-connected DERs to forge contracts with the SB instead of bilaterally. The SB would procure generation based on an integrated resource plan ("IRP") or another planning mechanism, similar to aspects of HECO Companies' PSIP or IGP. Ideally, the SB would be technology and ownership model neutral, procuring power and planning grid investments at the least cost for the system and passing its costs to ratepayers. *Technology neutral* means that the SB would consider storage and assess tradeoffs between/among wires, generation, storage, and behind-the-meter solutions.

4.1.8 Grid defection

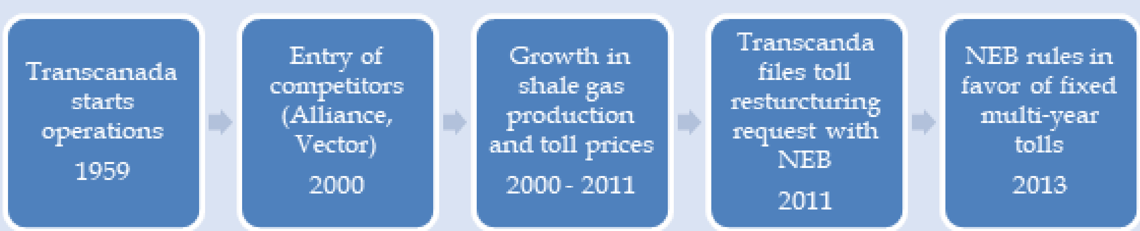
Grid defection is a situation in which customers reduce their reliance on the grid and ultimately stop using it. Under a grid defection scenario, parts of the grid may need to be abandoned; stranded costs could emerge in both generation and wire assets. Grid services could deteriorate, and the cost of serving underprivileged customers would increase. Generation ownership would be diverse, and microgrids (also under diverse ownership) would proliferate. Customers would effectively receive the level of reliability they wished to pay for, but the ability to pay or access to knowledge to self-supply would be a challenge for some customers. Overall, grid defection would become more likely over time if delivered costs are higher than DER costs and no action is taken to encourage alternative business models.

Task 1.1.1 *(Introduction of ownership models)* provides a more detailed discussion on the potential utility ownership models explored in this Study.

Lessons from TransCanada Mainline

A parallel example, although not a perfect analogy to this discussion, is emblematic of what happens when a firm formerly perceived as a natural monopoly is no longer one, is the case of the TransCanada Mainline. This example showcases the impact of competition on customer rates. TransCanada Mainline, one of the largest natural gas systems in Northern America, started operations in 1959. Until 1998, TransCanada mainline faced limited competition.

Starting in the 2000s, however, the competitive landscape began to shift as more competitors including Alliance and Vector pipelines began providing gas transmission services in the region. Due to the growing supply of gas, the amount of gas transported by the TransCanada Mainline significantly declined and resulted in substantially higher fixed costs and toll prices. In response, TransCanada presented a toll restructuring proposal to the National Energy Board ("NEB") in which it requested to shift $400 billion in yearly costs to users of the Alberta system. After further proceedings, the NEB decided to implement a long term fixed competitive price for tolls for a four-year period.



Source: TransCanada Mainline Decision

4.2 Advantages and drawbacks of each ownership model

The Project Team has assessed and compiled the pros and cons of each of the utility ownership models. This assessment is based on research and is informed by participants during community outreach events. The results are summarized in Figure 17. When viewed in light of the State's goals and energy objectives, the pros and cons assessment confirms that the ownership models selected for further evaluation (IOU, co-op, and SB models) may be best suited to Hawaii's context.

Figure 17. Summary of pros and cons of each utility ownership model

	Pros	Cons
IOU	• Has greater access to capital and human resources	• Goals of shareholders are not always aligned with State goals
New parent	• Can facilitate growth and innovation • Has various sources of capital	• May lead to potential financial distress if acquisition is heavily leveraged
Co-op	• May have access to concessional financing (via Rural Utilities Service, National Rural Utilities Co-op Finance Cooperation) if considered "rural" • Align stakeholder interests	• Strength of leadership may vary based on outcome of board elections • Local population might be unengaged or uninterested in electric utility management
Muni	• May benefit from access to tax exempt debt financing • They themselves may also be tax exempt, and exempt from various kinds of state and Federal regulations	• Difficulties in recruiting employees with adequate technical skills needed to run utility • May be subject to political interference and may face difficulty in mobilizing funds for investment
Hybrid (with majority government ownership)	• Little trouble mobilizing funds (as state-controlled utilities) • State ownership can present "halo" effect for raising capital; can raise equity on stock market instead of solely relying on retained earnings • Exempt from civil service restrictions	• Potential political interference • Conflicting incentives between entities on the board
Single Buyer	• Allows for optimized grid reliability, coordinated planning in sync with State goals, and competition for generation • Could lower rate levels by procuring energy in efficient manner • Technology and ownership model neutral	• Requires establishment of independent entity (for SB outside of the utility) • Need for amendment to Act 166 to include SB and grid access oversight functions
IDER	• IDER is independent but guided by state policy objectives • Creates distribution network of the future; explicitly targets creating a competitive distribution system	• Complex solution: redefines role of the utility, requires additional infrastructure and expertise • Would require significant investments to establish the institutions and infrastructure necessary
Grid defection	• Grid connections will ultimately be seen by customers as an option and valued accordingly	• Stranded costs could arise in both generation and wires • Cost to serve underprivileged customers would rise • Ability to pay, or access to knowledge for self-supply, represents a challenge for some customers

4.3 Similarities and differences between ownership models

The role of the utility is one of the key differentiating features of the various ownership models. The utility would still exist in all the models; nevertheless, there are differences in its ultimate goal and how profits (or surpluses, in the case of a co-op) are distributed.

The role of the regulator also changes under some of these models. Under a co-op or muni, the regulator would have less of an impact on setting rates or reviewing resource planning documents. However, the regulator might still be involved in setting reliability standards and regulating access to the grid. In all other models, the regulator would still be heavily involved in setting rates and approving investment plans. It would also have a responsibility in ensuring the fairness of procurements under the SB model, and in evaluating the effectiveness of integration and equality of access to the grid under the IDER model.

Responsibility for planning also differs among the models. Under the status quo and the other utility-centric models, the utility is responsible for planning with oversight from the regulator. Under the IDER model, utility planning likely shifts to the planning of the wire assets, with market forces driving generation location and planning (although some backstop planning for resource adequacy is likely required and may remain with the utility). Under the SB model, the SB is likely responsible for transmission and resource adequacy planning activities. Of course, in a grid defection world, planning becomes challenging as the utility will increasingly lack the means of implementing the plan. In such a scenario, planning likely defaults to the regulator and focuses on access for low-income customers.

Another area of distinction among the models is related to generation ownership and revenue streams. Under the utility-centric models, generation would continue to be included in the rate base and could be developed by the utility. Under the IDER and SB models, however, all or a portion of the generation assets could be taken out of the rate base. For future procurements, in the IDER model, non-regulated utility affiliates could still own generation resources, but they would be subject to greater regulatory scrutiny to ensure a level playing field. By contrast, in the SB model, provided the utility itself does not act as the SB, non-regulated utility affiliates would face less scrutiny because there would be less opportunity for favoritism.

Another potential area of distinction among the models is taxation. While various so-called "payment instead of taxes" or "Pilot" programs can be designed, co-ops and munis face different treatment with regards to property, local, state, and Federal taxes. Without a Pilot program, the creation of a co-op or muni can result in loss of local and state tax revenue.[82] Because the IDER and SB models involve greater participation by non-utilities, the impact on any taxes collected through the utility would need to be assessed. Under the grid defection model, both utility sales of electricity and sales for resale would be lower, and tax revenue would come from sales of DER equipment.

4.4 Evaluation of the ownership models relative to state goals

The Project Team evaluated the selected ownership models based on the four policy objectives established by House Bill 1700 (Act 124) of 2016, selecting six major criteria from which to assess an ownership model's ability to satisfy these policy objectives. The identified ownership models were qualitatively evaluated relative to the following criteria:

1. ***Ability to meet state energy goals***
2. ***Maximize consumer cost savings***

[82] While federal taxes would also be impacted, this is outside of this Study's scope except to the extent that it impacts rates.

3. ***Enable a competitive distribution system***
4. ***Address conflicts of interest***
5. ***Align stakeholder interests***
6. ***Assess transition costs***

The table below summarizes the relationship of each evaluation criterion to the guiding principles, while the paragraphs below provide further information.

Figure 18. State policy objectives and evaluation criteria

State policy objectives	Evaluation criteria	Notes
1) Achieve State energy goals	• Ability to meet State energy goals	Assess each model's ability to meet the State energy goals
2) Maximize consumer cost savings	• Maximize consumer cost savings • Assess transition costs	Consumer costs include both ongoing costs under the model, plus any cost associated with transitioning
3) Enable a competitive distribution system	• Ability to support a competitive distribution system	Assess each model's ability to allow for competition at the distribution level
4) Eliminate or reduce conflicts of interest	• Address conflicts of interest • Align stakeholder interests	Remove the potential for conflicts of interest in utility investments, and align incentives for all stakeholders

Ability to meet state energy goals

The ability to achieve state energy goals is explicitly listed as one of the four guiding principles and is a criterion which can be qualitatively assessed. Hawaii has the most aggressive renewable energy targets in the country. It aims for its utilities to achieve 100% of their electricity from renewable energy by 2045.[83] 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."[84] More specifically, the State aspires to achieve a diversified energy portfolio that makes the best use of land and resources; have an efficient marketplace that is beneficial to all and integrated and modernized grids, and be recognized as an energy innovation center.[85]

[83] HI Rev Stat § 269-92 (2015).

[84] 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.

[85] Ibid; Hawaii House Bill 416 (January 26, 2015), and House Bill 1494 (December 17, 2015).

While many of the ownership models can be made to meet most or all of the state's objectives, they differ in terms of effectiveness and the extent of regulatory intervention required. Ironically, government ownership forms (state control or muni ownership) may have greater challenges, given the potential susceptibility of these forms to short term political pressure. Grid defection is also a poor means of meeting the state's goals because although it would achieve diversification of energy resources, it would not be able to meet the other objectives. The Project Team's qualitative scoring suggests that the IDER and SB models would best help the state achieve its goals because they would be independent but guided by state policies.

Maximize consumer cost savings[86]

Maximizing customer cost savings is also one of the four major criteria and can be assessed from both a qualitative and quantitative perspective. The SB is the most favorable on the ability to maximize consumer cost savings because it is an independent body focused on long-term least-cost procurement. The co-op model scored second because of its ability to share surpluses with members, though there is the possibility that the co-op management may not always pursue long term least cost initiatives because the co-op' priorities are driven by its members-consumers' interests and needs and these might not always be the least cost. The IOU model is least favorable, largely due to the incentives under the cost of service regulation to over-capitalize the system. However, as noted above, if the profit motive can be appropriately harnessed, IOUs can be an effective means of delivering state policy. Munis rank low in this category primarily because of the risk that they will face pressure to pay above-market wages due to civil service rules and political considerations. Grid defection will not maximize savings; indeed, for those customers who remain with the utility, grid defection will mean a substantial increase in costs.

Enable a competitive distribution system

Enabling a competitive distribution system is one of the guiding principles and can be assessed from a qualitative basis. None of the traditional approaches to utility ownership models will enable a highly competitive distribution system. IOUs, munis, and co-ops all contain bureaucracies inimical to the promotion of new types of generation ownership, evolving ways to connect consumers, and bi-directional flows on the distribution system. The IDER approach is the best way to create the distribution network of the future, as it explicitly targets creating a competitive distribution system. While grid defection ranks second in this category, it lacks the benefits of coordination that an IDER structure would bring. Although the SB model would also facilitate competition, it retains a centralized approach to procurement which could undermine initiative and creativity.

Address conflicts of interest

Addressing conflicts of interest is one of the four guiding principles and can be assessed on a qualitative basis. Addressing conflicts of interest requires as much as possible separating planning and operational control from investment and ownership. Thus, many of the mechanisms which score well under the objective of creating a competitive distribution system also score well in addressing conflicts of interest. Even though grid defection is ranked relatively

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[86] The consumer cost savings considered in this section excludes consideration of implementation costs.

high in this metric, this may not be socially optimal. While those defecting from the grid entirely pay their full costs, they clearly no longer participate in a shared endeavor that allows for optimization among customer classes. This is why grid defection scores so poorly in the next category, aligning stakeholder interests.

Align stakeholder interests

The ability to align stakeholders (PUC, CA, Legislature, Utility, and Consumers) interest is one of the six major criteria as aligning stakeholders is necessary to achieve the four guiding principles. A competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs requires stakeholder alignment so that market participants are not working at cross purposes and stifling progress. Stakeholder alignment is also necessary to eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation, as moving forward, no one entity will have complete control over the buildout of grid resources. The extent to which any of the alternatives helps to align stakeholder interests partly depends on the regulatory framework in which it is embedded. Thus, while the separation of ownership, procurement, and operation principle continues to apply, the Project Team has not ruled out the possibility that a properly regulated IOU could align stakeholder interests; this could mainly be the case under new ownership by a public benefit entity. As noted above, grid defection fails to align stakeholder interests and would be the poorest of all the alternatives in this regard.

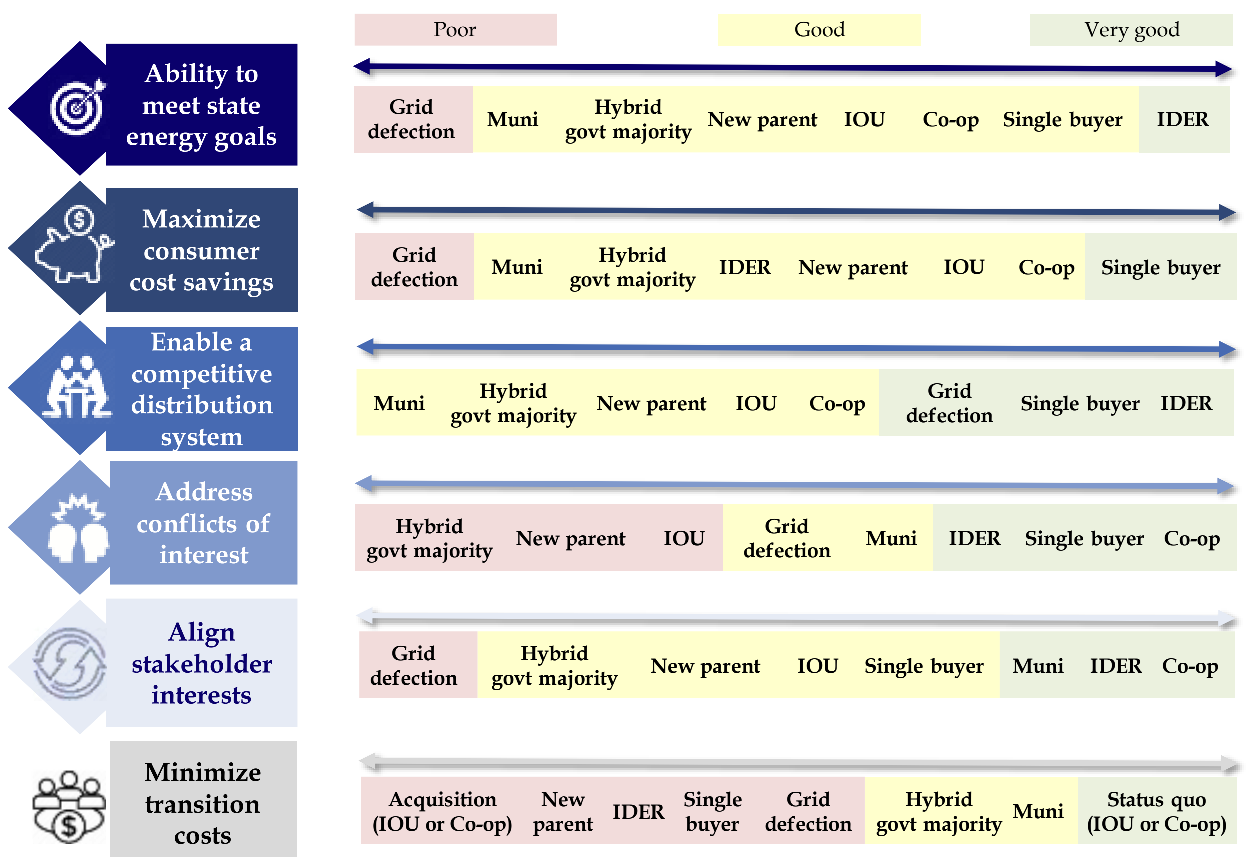
Assess transition costs

Assessing transition costs is explicitly called out as a major criterion as it acknowledges that there is an existing model that is being transitioned from. As a major criterion, it is fundamental to assessing the total cost impact to ratepayers. While arguably embedded in consumer cost savings, it is important to note that the various ownership structures differ substantially in transition costs. Depending on how entrenched the opposition from the utility, any transition may be subject to delay and litigation. The Status Quo (or IOU) would provide the lowest transaction costs while the grid defection would provide the highest transaction costs due to potential stranded costs. A cordial negotiated solution would minimize transition costs, even in those more complex solutions such as the IDER and ISO. One possibility to reduce transition costs could be a phased approach, for example, one in which the utility serves as the SB while an IDER ISO is being established.

Summary evaluation of ownership models relative to the criteria

The Project Team then performed a qualitative evaluation of the eight ownership models with respect to each of the six ranking criteria defined previously, assessing how each potential ownership model would help achieve the state policy objectives. The high-level results of this assessment are presented in Figure 19. Task 1.2.1 *(Comparison of ownership models)* includes the full discussion leading to the Project Team's evaluation of the ownership models with respect to the evaluation criteria.

Figure 19. Evaluation of ownership models relative to the ranking criteria



4.5 Feasibility of the ownership models

As mentioned earlier, one of the high-level assessments looked at the technical, financial, and legal feasibility of each ownership model.[87] Feasibility generally is defined as "the possibility that can be made, done, or achieved, or is reasonable."[88] These standards draw heavily from available literature and the guidelines of the PUC.[89] Figure 20 represents a summary matrix of the technical, financial, and legal feasibility of each ownership model.

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[87] Detailed engineering, financial, or legal feasibility studies were outside the scope of this high-level analysis.

[88] Cambridge Dictionary. For comparison, Merriam-Webster defines feasibility as "capable of being done or carried out;" and Oxford Dictionaries defines it as "the state or degree of being easily or conveniently done."

[89] These include standards of review for utility acquisitions and changes in ownership models in the cases of (1) the acquisition of Kauai Electric by the Kauai Island Utility Cooperative and (2) the proposed acquisition of the HECO Companies by NextEra Energy; 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, 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 "Exhibit A: Commission's Inclinations on the Future of Hawaii's Electric Utilities.

Figure 20. Summary matrix of the technical, financial, and legal feasibility of each ownership model

<table>
<tr><th>Model</th><th>Comply with reliability, adequacy, quality of service?</th><th>Require separation of some businesses?</th><th>Require costs to move to new model?</th><th>Require legal or regulatory changes?</th></tr>
<tr><td>1) Status Quo (IOU or co-op)[1]</td><td rowspan="7">Yes</td><td rowspan="5">No</td><td colspan="2">No</td></tr>
<tr><td>2) Owner change (IOU or co-op)[2]</td><td rowspan="6">Yes</td><td rowspan="2">No</td></tr>
<tr><td>3) New parent</td></tr>
<tr><td>4) Muni</td><td rowspan="4">Yes</td></tr>
<tr><td>5) Hybrid</td></tr>
<tr><td>6) IDER</td><td rowspan="2">Yes</td></tr>
<tr><td>7) Single Buyer</td></tr>
<tr><td>8) Grid defection</td><td colspan="4">No</td></tr>
</table>

Note: (1) IOU in Hawaii, Maui and Honolulu Counties; co-op in Kauai County (2) Change from IOU to co-op in Hawaii, Maui, and Honolulu Counties; Change from co-op to IOU in Kauai County.

Based on the analyses, all the models, except for grid defection, can theoretically meet the PUC standards for utility responsibilities. However, most utility models would also require additional hiring and workforce considerations, in part because of civil service restrictions or collective bargaining requirements (e.g., muni and potentially hybrid ownership models), and management or salary concerns (e.g., co-op, or to establish capacities or expertise in new areas such as the IDER and SB models).

In terms of financial feasibility, a friendly acquisition is potentially a necessary condition for the feasibility of the transition for a new owner, muni, hybrid (majority government ownership), and co-op models. While a "hostile" acquisition could be managed, this is likely to significantly escalate acquisition and transaction costs that the buyer will attempt to pass onto consumers. For the IDER and SB models, the costs required to set up these models would vary depending on the mechanisms under each model.

Lastly, legal or regulatory changes are needed to allow for the establishment of independent IDER and SB entities. For the muni, legislative action is needed at a minimum and requires either a local referendum, county council action, or state action on municipalization. The succeeding subsections discuss the different feasibility aspects of the ownership models.

4.5.1 Technical feasibility

Technical feasibility evaluates whether the ownership model in question enhances or detracts from the utility's ability to carry out its roles and responsibilities for the State, including its ability to contribute to the achievement of state energy goals. The PUC has identified the roles of an electric utility in various regulations and laws. These include providing adequate and reliable energy supply, avoiding interruption of services, complying with standards set by the PUC, and maintaining service quality, to name a few.

Based on the high-level assessment, all the models—except for grid defection—can theoretically allow utilities to meet their responsibilities as set by the PUC. Moreover, for most of the ownership models, the role of the utility is unchanged in generation, transmission, and distribution, with the assumption that current regulations remain unchanged. Exceptions to this rule are the SB and the IDER models, which require the separation of some of the business entities that are currently within the utilities. For the IDER model, there might be a need to separate the generation business. For the SB model, the procurement division of the utility would need to be separated from the utility, either through ring-fencing mechanisms (for the SB within the utility) or as a stand-alone entity (for the SB outside the utility).

4.5.2 Financial feasibility

Financial feasibility evaluates the financial characteristics of the ownership model, including whether it is possible (from a financial perspective) to implement the ownership model and what financial benefits or costs would accrue to ratepayers.

One potential upside of a new IOU owner (under the new parent model) by being investor-owned, is that it may have broad access to capital markets. However, this access to capital markets does not necessarily entail lower costs of capital, since the cost of capital can vary according to market conditions, the nature of the asset, and the characteristics of the acquiring entity. Nor is it necessarily guaranteed that broad access to capital is unique to an IOU owner. Another potential upside is that the merger or acquisition improves the finances of the HECO Companies, allowing them to borrow at a lower cost. Such improvements in credit ratings and access to capital also depend on the nature of the acquiring company. If achieved, credit improvements could entail the procurement of improvements and infrastructure in a more cost-effective manner, since the cost of debt for such projects would be lower. Overall, while there are many possible benefits of a new IOU owner, these financial benefits are not intrinsic to the IOU model and rely on additional characteristics, including the nature of the proposed transaction, characteristics of the acquiring entity, or PUC enforcement of its guidelines for ownership transitions, among others.

Under the Hybrid with majority government-owned model, a significant up-front investment is involved in acquiring the majority share of the company. It could be assumed that the Hawaii state government would most likely purchase the majority share of utilities through bond issuance under this ownership model. However, it may potentially allow for a longer-term lower cost of capital if investors view the government as absorbing some of the risks of the business. Currently, such a purchase may initially increase the overall debt of the State of Hawaii; the long-term impacts are uncertain. In terms of initial feasibility, it should be noted that Hawaii has an optimal credit rating, with a credit score AA1 from Moody's, AA+ from S&P Global, and an AA rating from Fitch as of May 2017.[90] This implies that there is room for the Hawaii government to undertake debt at a reasonable cost. Financial feasibility under the Hybrid ownership model is subject to the transaction, limits on bond issuance, and government management.

The acquisition cost by a muni would depend on the nature of the acquisition and any negotiations or proceedings that would accompany the purchase. Munis have access to tax-exempt capital for improvements following the initial acquisition, which remains taxed. This can help ensure the cost-effectiveness of improvements made to achieve Hawaii's clean energy vision. However, there are limits on a town's bonding authority, subject to the credit of the municipalities in question, the cost of servicing such debt, and other legal limits of bond issuance. If the county governments seek to municipalize, most have positive credit ratings, either as Aa1 or Aa2, for their general obligation bonds.[91] This means that county credit ratings could potentially support an acquisition. However, the county governments will have to consider whether they would be willing to make the long-term financial commitment to buy the county operations and infrastructure of their utility.

The Hawaii state and municipal governments generally have strong credit ratings to undertake the debt required to acquire assets at a relatively lower cost. However, there are limits on municipal bond issuance while the expenditures would be quite substantial in all cases, whether it is a hybrid or a municipal model. Munis can also take advantage of tax-exempt bonds—which can potentially be lower than market-based rates—due to their association with a municipality.

Co-ops often have access to low-interest financing, which allows them to purchase assets at lower costs for their members. In terms of the initial acquisition, members could contribute equity to the purchase of the utility assets, and the transaction is not significantly different from any other entity that seeks to purchase utility assets. In lieu of equity, the co-op could assume ownership by leveraging high amounts of debt, which is a more likely pathway for cooperative acquisition. The cost of such debt can vary but is generally between 1% and 5%.[92] However, by relying primarily on debt for the purchase of utility assets, a cooperative utility may have difficulty in limiting rate increases during the repayment period. But, even if co-op members are unable to contribute significant amounts of equity to the utility and subsequent improvements, co-op members have access to low-cost financing through both federal and cooperative lending sources. The USDA RUS, for example, has specific loan programs to support energy efficiency and renewables, and additional grant programs specifically for high-cost energy areas.[93] Other dedicated cooperative lenders, such as CoBank and the Cooperative Finance Association, also

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[90] The Pew Charitable Trusts. "Rainy Day Funds and State Credit Ratings." May 2017. <http://www.pewtrusts.org/~/media/assets/2017/05/statesfiscalhealth_creditratingsreport.pdf>

[91] Moody's. Ratings of GO Bonds for Hawai'i (Aa2), Kauai (Aa2), Maui (Aa1), Honolulu (Aa1).

[92] See Kauai Island Utility Cooperative. "Consolidated Financial Statements, December 31, 2016 and 2015." Note 8- Long-term Debt. Page 17. <http://kiuc.coopwebbuilder2.com/sites/kiuc/files/PDF/financials/2016%20Audited%20Financial%20Statements.pdf>

[93] Cowan, Tadlock. "An Overview of USDA Rural Development Programs." Congressional Research Service, February 10, 2016. <http://nationalaglawcenter.org/wp-content/uploads/assets/crs/RL31837.pdf>

provide dedicated sources of financing to electric co-ops. Finally, even if the co-op cannot own and operate all the projects itself, it can also procure them from other entities. These financing mechanisms can help co-ops secure the financing for Hawaii's clean energy vision while dampening any increase in the rates of consumers.

There would be set up costs involved for the SB models. Under an SB where it is still part of the incumbent utility, set up costs would include a separate office for the SB, IT infrastructure, and other ring-fencing mechanisms to ensure that the SB is independent of the utility. Under an SB where it is outside of the utility, additional infrastructure investments need to be made. Although the final cost of establishing an SB is unclear due to its many variations, housing the SB within the incumbent utility might from a technical standpoint be less expensive due to the preexisting role that incumbent utilities already play in procuring generation from IPPs in Hawaii. If another entity undertakes that role, it would have to develop and acquire that expertise and need to invest in infrastructure to operate the SB.

Similar to the SB models, the IDER model entails set up costs to build the platform and the infrastructure needed for the customers, DER providers, and other market participants to transact. In New York State, some pilot programs on IDER have been implemented. One of these programs is the Buffalo Niagara Medical Campus DSP Engagement Tool where the hospital campus is used as a testbed for the distributed system platform ("DSP") functionalities and used to coordinate and optimize the DERs throughout the campus. This pilot program's capital expenditure was $4.4 million, and the costs of the operation are $385,000 for less than a 3-year period.[94] Nevertheless, it is difficult to assess the overall financial outlook for the IDER model due to insufficient data. Ideally, the IDER model should be able to optimize value streams and deliver such benefits to ratepayers through an efficient and competitive marketplace. In doing so, it could achieve the State's clean energy goals at market-based prices. However, the cost to establish the institutions to govern this market could be considerable.

In summary, while utilities generally are open to acquisition with a sufficiently high purchase price, higher acquisition costs would likely result to increase in electricity rates. The willingness of the incumbent utility to sell its assets plays an essential role in determining the acquisition cost when transitioning to a new owner, be it be another IOU, a muni, a co-op, or another government vehicle. For IDER and SB models, set up costs could be sizable, depending on the mechanisms that are required to operate these models.

4.5.3 Legal feasibility

Legal feasibility assesses whether the transition to another ownership model is possible given current laws, statutes, and regulations.

The shift to new IOU owner and co-op models (assuming the co-op would be regulated to the same extent KIUC is currently regulated) would not require new legislation or regulation because a prior legal framework is already in place. However, the new IOU owner would have to pass

[94] National Grid. Distributed System Platform REV Demonstration Project Q2 2017. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFF2D4106-57EE-469A-A32C-201ABAFB1BE2%7D>

the scrutiny of the PUC and obtain its approval for a transfer of control. Grid defection would also not need any legal changes; instead, high electricity prices and declining costs in solar and storage would incentivize defection.

The muni model represents somewhat uncharted legal territory for Hawaii since municipalization has never been attempted. The muni model would, at a minimum, require either a local referendum, county council action, or state action on municipalization. Moreover, if municipalization is pursued against the wishes of the incumbent IOUs, legal questions may arise regarding the intersection between the county's eminent domain powers and the PUC's right under state law to approve or deny the disposition of utility assets. These questions would need to be resolved by the courts, PUC, and/or state legislation.

For the Hybrid with majority government ownership model, legislative action at the State level would be necessary to establish a holding company and allocate funding for the purchase of a majority of shares of the utility. However, such a takeover of a private utility that is financially solvent would be largely unprecedented in the United States.

For the IDER and the SB models, the PUC and/or legislature would likely need to make significant legal changes to establish the IDER model or have a separate and independent[95] SB. The specific type of action varies significantly depending on the particular model pursued. Legislative action may be necessary for the IDER model to establish an entity that can monitor and develop the market for DERs. The IDER model would also require several novel approaches, for example creating new value streams for DERs, or changing rate setting methodologies to incentive utility innovation, among others. The SB and the IDER models would require some form of separation between/among generation, transmission, and distribution assets.

Task 1.3.1 *(Identification of various steps, timeline, and costs)* discusses in detail the indicative steps, timeline, and costs necessary to change from the current ownership model to the new models.

4.6 Infrastructure needs with the change in the ownership model

Changing the ownership model of utilities in the State would not change the infrastructure required to achieve the State's energy goals (especially in grid modernization technologies) significantly. More specifically, infrastructure requirements will not differ drastically, whether owned by an IOU, co-op, or muni. However, a grid defection scenario would likely result in substantial stranded assets. Currently, the incumbent utilities—HECO Companies and KIUC—already possess the necessary infrastructure to reliably operate the grid and have prepared long-term plans to ensure continued reliability while achieving the RPS targets. Moreover, the roles and responsibilities of the electric infrastructure owners under the new ownership model would be the same as they are currently.

[95] Independent can either be (i) independent of the other business entities within the HECO Companies or the KIUC (such as generation division, transmission division, etc.) or (ii) independent of the entire HECO Companies or the KIUC.

On the other hand, the SB model would require new infrastructure investments initially upon its establishment, whether as a stand-alone entity or a ring-fenced unit within the existing utility. The checklist for establishing an SB under either variant of the model is mostly the same, but some of the technology and capability needed for more sophisticated resource planning may have to be replicated in both the SB and utility.[96] This outcome was observed in the case of Ontario Power Authority—an SB in Canada—which spent more than CAD $3.5 million (in 2005 dollars) in capex during its first year of operation. The investment covered costs of furniture, computer hardware and software, telephone system, and leasehold improvements.[97] The adoption of the model in Hawaii would likely require a lower investment cost because the office for the SB would be smaller, and the cost of technological improvements has been declining.

The incumbent vertically integrated utility must divest from its generation business and would only own the wires[98] assets under the IDER model. Therefore, the utility investments under an IDER model would be focused on advanced grid technologies, which had also been proposed by the HECO Companies. The IDER model would eventually allow peer-to-peer transactions across the distribution grid. For example, the IDER system operator, which could be the utility or an independent entity, would need to manage energy and payment flows among many different market participants. These types of market operations would require additional investments for the provision and protection of data as well as for ensuring a higher level of market participation from customers, DER providers, and other service providers. The Project Team reviewed the pilot programs and enabling technologies used in New York and observed that the infrastructure investments for the first five years of pilot projects range from $11 to $190 million.[99] The costs vary based on the technology, utility service area, and the current status of utility infrastructure.

To summarize, the review of ownership models indicated that only the SB and IDER models would require additional infrastructure and capability needs in the transition. The Status Quo (IOU), co-op, and grid defection models would not require additional infrastructure investments for the transition. Task 1.1.4 *(Assessment of future needs for generation, transmission, and distribution infrastructure)* provides a high-level discussion of the future infrastructure needs under each proposed utility ownership model.

4.7 Potential stranded costs

Stranded costs represent costs that a utility was allowed to recover through regulated rates but whose recovery may be impeded or prevented as a jurisdiction transitions from a regulated regime to a competitive, deregulated environment. Assets become stranded when a utility can no longer recover the costs incurred to acquire and operate them through the rate base. Historically,

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[96] Detailed information on the steps in the setting up of a SB model, if chosen as one of the recommended utility ownership models, is discussed in Task 1.3.1. Identification of various steps, timeline, and costs required to change from current ownership model to new models, including regulatory approvals.

[97] Ontario Power Authority. *Ensuring Ontario's Electricity Future. Annual Report 2005.* March 2006. February 16, 2018.

[98] Wires assets include transmission and distribution assets.

[99] Tweed, Katherine. "Rate Base It! A Primer on New York's Distributed System Implementation Plans." Greentech Media. July 2016.

utilities have been allowed to recover their stranded costs provided that the investments were prudent and verifiable, as is typically expected if they had been subject to prior regulatory approval.

Due to the fact that each island operates an independent power grid, there are no existing alternative sources of power to those currently serving each county's load. Therefore, a change in ownership model of utilities would still require careful planning (and if necessary, additional investments) so that these assets would continue to ensure adequate supply and reliable transmission/distribution of power to customers.

Absent a change in the regulatory model that would introduce market-based constructs, all assets required to operate the power grid would remain in the rate base, or stay under contract with the new entity, which would then recover the contract costs from ratepayers. Therefore, a change in ownership model under the current regulated regime would not result in stranded costs, which must be recovered from ratepayers.

Figure 21. Summary table of potential stranded costs for each ownership model

Ownership model	Generation assets	Transmission and distribution assets
Traditional utility models: • IOU (status quo or new owner) • Muni • Co-op • Hybrid - majority government-owned	No stranded costs	T&D assets remain under regulated regime, hence no stranded costs are expected
IDER	Potential for stranded costs if generation asset have lower value under a new regulatory model than under current regulated regime	T&D assets remain under regulated regime, hence no stranded costs are expected
Single Buyer		
Grid defection	Technically no stranded costs would result as assets remain in rate base. However, there would be a growing number of assets no longer used and useful, resulting in growing costs being spread over a smaller and smaller group of customers	

However, the IDER system operator and SB models would require a change in the regulatory structure so the framework that would govern market-based compensation of generation resources may be created. Therefore, there is a potential for stranded costs if generation assets under the new regulatory structure have a lower value. In general, thermal generation plants that are less than 30 years old are more likely to become stranded because they may retain a useful accounting life beyond when they are made obsolete by a 2045 100% renewable portfolio standard. In the case of the Hawaii utilities' thermal generation fleet, which is valued at approximately $1,200 million with about 400 MW of generation capacity that is less than 30 years in age,[100]a portion could potentially be a source of stranded costs under a change in ownership and regulatory structure to IDER system operator or SB. However, renewable generation is not

[100] Based on LEI's analysis of regulatory filings by the HECO Companies and KIUC.

expected to replace thermal generation overnight, so an asset would have likely recovered much of its book value by the time it is retired.[101] Task 1.1.6 *(Identification of estimated stranded costs for each ownership model)* discusses the potential stranded costs for each model in detail.

4.8 Views from stakeholders

The community outreach for the utility ownership models was conducted between October 9, 2017 and October 13, 2017 on the islands listed in the textbox on the right. The Project Team notes that the survey of the public was not a statistically representative sampling of the population but was intended to be illustrative of a range of views.

Location of the Community Outreaches

- City and County of Honolulu
  - Honolulu
  - Waialua
- 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 from the preliminary analysis of the ownership models, to receive their input on what they value in their utility, and input on the advantages and disadvantages of different ownership models in meeting those values. Combined, 141 stakeholders participated in the public workshops.

In addition to the workshops, the Project Team conducted multiple bilateral meetings as part of the ongoing stakeholder engagement process throughout the entirety of this project. The Project Team met with 20 energy industry, government, and other stakeholders from across the state. Input varied from the importance of leadership (of both the utility and the Hawaii Public Utilities Commission) to the technological opportunities for addressing specific needs (e.g., microgrids and resiliency), to the value of local influence on decisions, to the need for innovation and nimbleness to address the state's needs.

Throughout the process, stakeholders who participated in the community outreaches repeatedly raised concerns on the current high electricity rates. They also mentioned the ability of the stakeholders to be engaged in and influence utility decisions to ensure they are aligned with community needs; demand for more renewable energy, from more diverse sources, and for more opportunity for customer-sited generation; and enabling competition to improve efficiency, to name a few.

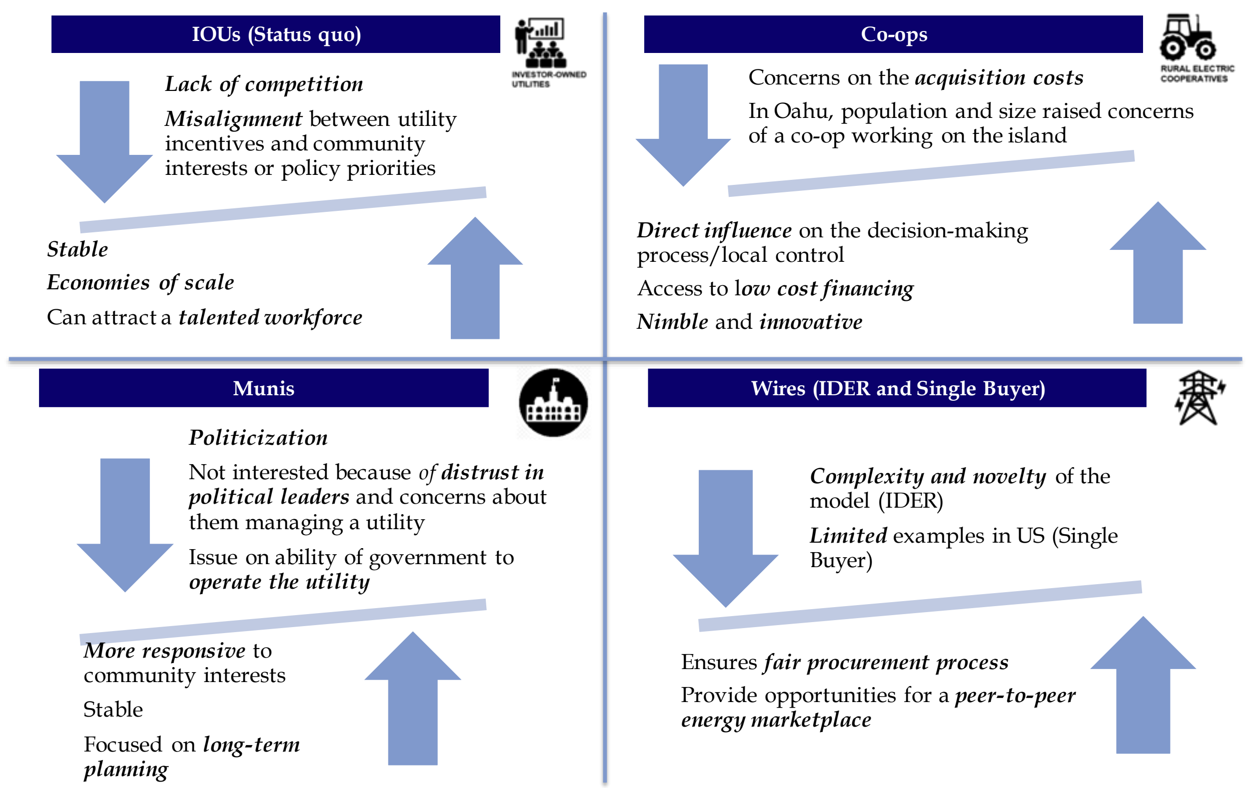
The participants also provided their views on the different ownership models. In general, participants in the community outreaches expressed that IOUs were typically stable, benefitted from economies of scale, and could attract a talented workforce. There was a concern, however, about a lack of competition and a misalignment between utility incentives and community or policy priorities. Stakeholders often expressed concern that they see IOUs as driven primarily by increasing shareholder profit and that they do not view IOUs as innovative in adopting new technologies. Some stakeholders were interested in how what they saw as a misalignment of

[101] The annual straight-line remaining-life depreciation rates vary by generation asset accounts but average approximately 2%.

interests could be addressed through regulatory approaches, or the adoption of new investor-owned utility models, such as B-corp.

While stakeholders who participated in the outreach meetings liked that the muni model allows for community members to have a more direct influence on utility decisions, many stakeholders were concerned about the potential for political influence to hinder utility operations. Additionally, many expressed concerns that the government would not operate the utility efficiently. With the exception of a few stakeholders, there was little interest in this model.

Figure 22. Pros and cons of the different ownership models according to participants to the community outreach meetings



On the other hand, many stakeholders during the stakeholder outreach meetings agreed that the primary benefit of the co-op model is the ability that consumers have to impact utility decisions directly. Many pointed to KIUC as a successful example of the co-op model and, based on that example, the potential that this model has for providing lower rates. A number of stakeholders mentioned that this model works best with educated, engaged members, and there are difficulties in achieving this. The interest in the co-op model varied by island, with more interest expressed on Kauai and the Big Island (particularly at the Hilo meetings). Some stakeholders at the meetings on Oahu (both Waialua and Honolulu) and Maui were not sure that this model would work on their respective islands due to population size, geographical diversity, and concerns about qualifying for rural financing programs.

The wires-only models, which include the SB and the IDER models, were discussed in detail during the workshops in Honolulu, Kona, Wailuku, and Waialua. The stakeholders felt that a primary benefit of this model is its potential for encouraging competition in generation and that this could result in lower rates. Nevertheless, the participants recognized the novelty of the concept and that there are limited examples to learn from. Figure 22 summarizes the pros and cons based on the comments of the participants.

In general discussions, some participants in the community outreaches felt that a change in ownership model might not address their community's priorities and expressed interest in understanding how regulatory changes could incentivize utilities to align their actions with community goals. When discussing a theoretical change in ownership, many stakeholders highlighted that the transition costs would be too high to bear without a willing seller. Task 1.2.4 *(Outreach Plan and documentation of results of public outreach)* provides an additional discussion on stakeholder views regarding utility ownership models.

4.9 Ownership models selected for further study

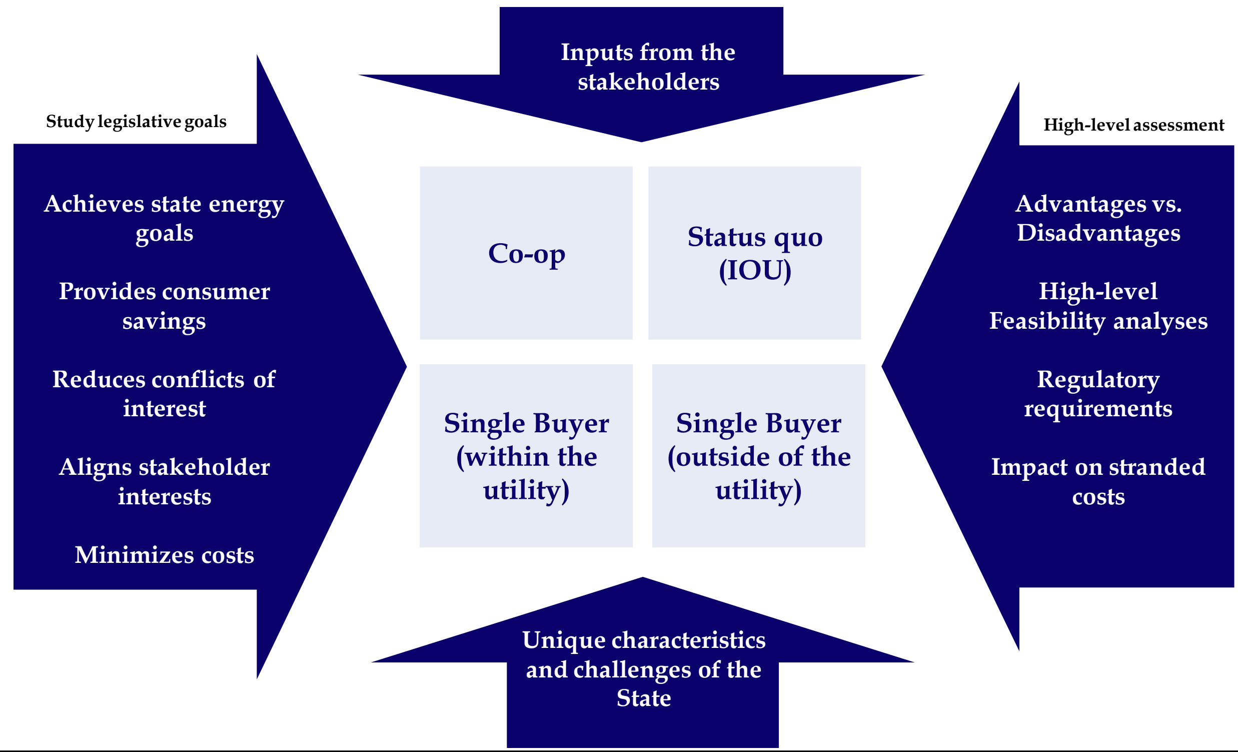
Taking into account the Study's legislative goals, inputs from the stakeholders, results of the high-level assessments, and the State's unique characteristics and challenges, the IOU, co-op, and SB models (within and outside of the utility) are the most beneficial utility ownership models among the eight models for further review. Notably, the IOU model on all islands except Kauai, and co-op model on Kauai represented the baseline against which the alternative models were compared.

Reflecting on the establishment of KIUC, many stakeholders have expressed support for the establishment of a similar co-op system in each of the islands. Compared with an IOU, the co-op model is perceived to lead to the stronger alignment of stakeholder interests because the consumers in this model are also the owners. Moreover, it eliminates or at least lessens the profit motive that is more inherent in IOUs. Furthermore, the co-op has access to lower cost debt financing insofar as the typical market rate for utilities is applied. However, a transition to the co-op model beyond Kauai would likely require a significant debt-based purchase from the incumbent utility, which may have long-term impacts on ratepayers. Moreover, co-op leaders are elected by members, so the competence of managers would depend on the outcome of these elections.

The SB model outside of the utility ranks highly because of its significant role in addressing several perceived deficiencies with the IOU model (such as conflict of interest within utility operations, the fair conduct of the procurement process, independent energy, and capacity planning). At a high level, the SB entity in this model is expected to procure energy for the long term at the least cost, which is likely to create consumer cost savings and facilitate competition for power supply contracts.

Similar to the "outside" SB model, the SB model inside the utility generated a high score because it can address perceived deficiencies of the IOU model (such as conflicts of interest within utility operations and the fairness of procurement and planning processes). Its main responsibility is also focused on procuring energy at the least cost. Unlike in the "outside" SB, the SB here can draw from existing utility staff and expertise more readily. The grid defection, hybrid ownership (with a majority government stake), and traditional IOU under a new owner model generated the lowest scores. They were judged to be least effective in supporting the State policy goals and preventing rate volatility. Task 1.2.5 *(Ranking process and rationale for the recommendation of three feasible utility ownership models)* discusses the methodology and results in detail.

Figure 23. Utility ownership models selected for further analysis



4.10 Indicative timeline to transition to another model

4.10.1 Ownership transfer

The process of transferring ownership of utility assets, either IOU to co-op or co-op to IOU, is estimated to take between two to three years, based on the experience of KIUC and the U.S. Department of Agriculture ("USDA") as well as assumptions about the process going forward in Hawaii following KIUC's precedent. The acquisition process for KIUC took approximately three years,[102] but a future acquisition could be shorter because stakeholders have learned from KIUC's experience.

For a co-op specifically, there is increased familiarity with the co-op model among the local population, and the public perceives KIUC as a successful utility. The USDA notes that the

[102] KIUC was officially formed in November 1999 to purchase Kauai Electric from Citizens Communications. In 2000, the PUC denied the acquisition of Kauai Electric by KIUC, prompting a subsequent renegotiation and regulatory proceeding in 2002 that culminated in the approval of the acquisition. The final acquisition occurred on November 1, 2002. This suggests that a timeline for subsequent acquisitions by prospective co-ops could be shortened through sufficient preparation for regulatory proceedings.

process for the formation of a co-op can take up to two years.[103] The process for setting up a co-op involves four key phases, namely: (i) establishment; (ii) purchase; (iii) regulatory approval; and (iv) subsequent operation. Figure 24 summarizes the key steps in the establishment of a co-op ownership structure.

Figure 24. Key steps in the establishment of a co-op

Steps		Timeline (months from start)
Phase 1	**Establishment**	**1 - 6**
	Initial Leadership and Stakeholder Discussion	1 - 2
	Formation of Provisional Committee	1 - 2
	Survey of Local Population	2 - 3
	Formationg of Steering Committee	2 - 3
	Incorporation and Bylaws	3 - 5
	Membership Recruitment Campaign	3 - 5
	Founding Assembly and Board Election	6
Phase 2	**Purchase**	**3 - 24**
	Feasibility Study and Financial Analysis	3 - 5
	Fund, Negotiate, Purchase Assets	6 - 24
Phase 3	**Regulatory Approval**	**3 - 24**
	Legal Outreach	3 - 24
	Regulatory Approval	13 - 24
Phase 4	**Operation**	**25 - 28**
	Transition of Workforce	25 - 28
	Commence Operations	28

4.10.2 Single Buyer

The formation of the SB could take between two and five years, with significant variability based on intervening factors, such as the contentiousness of legislative and PUC actions. The SB model carries some measure of uncertainty when it comes to the steps required for its establishment. Some result from the lack of existing empirical data from which Hawaii could learn from, as there are limited examples to draw from in the United States. The Project Team assumed in this case that the incumbent utility would be an IOU and that the SB would take over the functions of procurement (of all new generation capacity additions) and system planning, but not grid operation or dispatch. Based on the experiences of the Ontario Power Authority for a SB model outside of the utility and TNB in Malaysia for an SB model within the utility, as well as knowledge of the timelines required for the legislative and regulatory process in Hawaii, the timeline of 3-5 years is estimated for the establishment of a SB model, although the timeframe for the SB within the utility would be shorter. Figure 25 shows the indicative steps required to transition toward an SB model from the Status Quo. Task 1.3.1 *(Identification of various steps, timeline, and costs)* provides a more detailed discussion on the steps and timeline of the co-op and SB models.

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[103] U.S. Department of Agriculture. "How to Start a Cooperative." Presentation slides. No date cited. <https://www.rd.usda.gov/files/publications/How%20to%20Start%20a%20Co-op.pdf>

Figure 25. Key steps in the establishment of an SB within the utility

Steps		Timeline (months from start)
Phase 1	**Preliminary Discussions and Analysis**	**1 - 3**
	Initial Leadership and Stakeholder Discussion	1 - 3
Phase 2	**Establishment**	**4 - 36**
	Legislative Enactment	4 - 12
	PUC Proceedings	4 - 33
	Incorporate, Establish Bylaws, and Draft Rules	34 - 36
Phase 3	**Operation**	**37 - 42**
	Staff the Single Buyer	37 - 42
	Organizational and Operational Transformation	37 - 42
	Establish and Refine Planning Process	37 - 42
	Commence Operations	42

4.11 Required legal changes

Co-ops and IOUs are legally feasible utility ownership models in the state, and a regulatory change is not necessary for either establishment. Nevertheless, in order to develop a co-op, the organization would need to demonstrate that it has undertaken the appropriate steps, due diligence, and preparation for its establishment (e.g., in terms of achieving nonprofit status, compliance with tax laws and state regulations that define co-ops, etc.) and subsequent planning so it can meet the standards outlined by the PUC for transferring, owning, and operating utility assets. A new IOU would similarly need to meet those standards. Indeed, the PUC still needs to approve the transaction whereby the new owner (co-op or IOU) acquires the assets from the incumbent utility.

For a co-op, the necessary legal or regulatory frameworks that could help ensure its viability and overcome potential barriers already exist. For example, co-ops seeking to serve non-rural communities—particularly in urban environments of Maui, Oahu, and the Big Island—may find it difficult to raise the capital (for the purchase and transfer of ownership of utility assets) from traditional lenders such as RUS. Faced with this hurdle, policymakers could help in reducing this burden (e.g., drawing on the preexisting legislative authority of HRS § 39A-191, which further provides special purpose revenue bond support to aspiring co-ops). Additional regulatory measures could be crafted to help reduce the risks of utility ownership, thus, lowering the cost of capital for such endeavors. Nevertheless, it may be advisable to seek legislation that would specify and clarify how and to what extent the newly formed co-op, as a public utility, should be regulated by the PUC.

Finally, prospective owners should be aware that prior mergers and acquisitions proceedings do not constitute a legal precedent. Regardless, lessons can be drawn from the guidance of the PUC provided in the Appendix of the NextEra *Decision and Order* in presenting their case for approval. There is no *de facto* reason why a co-op would be unable to meet the standards outlined. Some of the standards likely bear little relevance to the case of the co-op and, in some cases, the co-op outperforms the standards outlined in that Decision and Order (e.g., reflecting local community stakeholder input). Additional risks, including possible mitigation measures that may impact these standards, are outlined more thoroughly in Task 1.3.3 *(Identification of risk for each ownership model, analysis of each risk, and assessment of the overall risk profile for each ownership option).*

Likewise, the transition to an SB within the utility model may not require enabling legislation. In such a scenario, the utility would be performing responsibilities that are similar to those that it had been performing before (considering that the SB is only performing procurement and planning). The key difference is that the ring-fencing further segregates the personnel and assets that are implementing these core responsibilities from the other activities of the utility. Moreover, since the utility would continue to house the key functions of procurement, it arguably still maintains its privileges under the franchise agreement, albeit with more stringent guidelines. Both processes—procurement and planning— have precedent in previous PUC guidance and action. It is possible that the PUC may shape the utilities' procurement and planning functions further towards an SB model without legislative action. However, without legislative action, the PUC is not required to take the initiative in implementing the SB model, and it is possible that the PUC may not take action if there is no mandate—even with legislative action.[104] Therefore, the establishment of the SB within the utility model would be legally feasible, and there is significant latitude over how the initial studies and eventual establishment could occur if pursued.

In contrast, the establishment of an SB outside the utility would almost certainly require enabling legislation, because it would need to be created by a governmental agency or be contracted by a public agency. Additionally, an "outside" SB would likely not be considered subject to PUC regulation as a public utility because it would sell all of the electricity it purchases directly to HECO for transmission or distribution to the public. State statutes provide that an entity that sells all its electricity (except that used for its own consumption) directly to a public utility for transmission or distribution are precluded from being considered a public utility.[105,106] Because the PUC's authority and general investigative power are limited to public utilities, an express grant of jurisdiction or responsibility would be required to confer the PUC with the power to regulate the "outside" SB. Without such legislation, the PUC's ability to regulate the SB outside of the utility would be limited to regulating utilities' transactions with the outside SB.

Task 1.3.2 (*Identification of legal changes needed to implement the proposed utility legal framework options*) provides a more detailed discussion on the legal feasibility of these ownership models.

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104 See, e.g., Act 166 (2012), in which the legislature authorized, but did not require, the PUC to contract with a Hawaii Electricity Reliability Administrator ("HERA") to develop and implement local reliability standards and interconnection requirements with accompanying enforcement in a manner comparable to the role filled on the mainland by the North American Electric Reliability Corporation and the regional oversight entities. See Act 166, S.L.H. 2012 § 1 Act 166, S.L.H. 2012 § 1; HRS Chapter 269, Part IX.

105 HRS 269-1 and HRS 269-141.

106 HERA is distinct from the "outside" SB because it is legislatively authorized and would consist of an entity that the PUC would contract with to carry out reliability functions (adopt and regulate interconnection standards) that the PUC normally does itself and would be subject to PUC regulation.

4.12 Potential costs related to a transfer in ownership of utility assets

Any transaction involving a change in the ownership of utility assets, be it from IOU to co-op or co-op to IOU, involves costs. Such a transition could also result in a change in the approach used to calculate the utility's revenue requirement. For instance, the revenue requirement for an IOU is calculated through a rate of return COS approach, while the TIER approach is used for co-ops. The transition would also change some upfront or non-recurring costs and recurring costs.

In the case of a co-op, the cost estimates for its creation (which include stakeholder outreach, cost-benefit analyses, incorporation, and regulatory approval) and transition of current IOU staff are based on the expected timelines and level of engagement required. The acquisition cost estimates are derived from the results of a comparable transactions analysis that the Project Team conducted. For those interested in understanding the detailed assumptions underlying these cost assumptions, Task 1.4.2 *(Identification of legal changes needed to implement the proposed utility legal framework options)* summarizes the approach in estimating these costs, with additional details in Tasks 1.3.1 (*Identification of various steps, timeline, and costs*).

The estimated upfront costs, which refer to the initial expenses to operationalize the co-op, include establishing a co-op, purchasing the assets from the incumbent utility, and transitioning current staff and operations to a co-op model. These costs are summarized in the table below.

Figure 26. Indicative acquisition and transition costs to a co-op model

	HECO	HELCO	MECO
Acquisition cost – purchase price	$3.25 billion	$0.76 billion	$0.65 billion
Establish a co-op	$2.3 – $3.3 million		
Transition and training of current utility staff	$0.25 million		

Source: LEI analysis. The Project Team evaluated nine previous acquisitions involving comparable utilities and analyzed the Enterprise Value; Equity Value; Earnings Before Interest, Taxes, and Depreciation ("EBITDA"); and Net Incomes of the acquired utilities. The numbers in the table above were calculated by averaging the valuations estimated using Enterprise Value/EBITDA and Equity Value/Net Income comparisons.

Under the co-op model, the reductions in utility expenses would help in part offset the upfront costs. These utility expenses include interest, income tax, and, potentially, regulatory expenses. The co-op could secure subsidized debt to finance the acquisition costs upfront, but the ratepayers bear the costs of servicing this debt over time. With the TIER-based ratemaking approach, capital costs for a co-op include the interest expense on its debt as well as the required interest coverage. As members accrue equity in the form of patronage capital retained by the co-op, capital costs decline relative to an IOU.

Co-ops also offer immediate and concrete savings from avoided federal income tax expenses. Since co-ops are tax-exempt at a federal level, they are only required to pay state income taxes. Compared to their 2016 tax liabilities as IOUs, the HECO Companies would have seen an estimated $41 million reduction in tax expense if they were co-ops and exempt from federal income taxes. Figure 27 shows the breakdown of these savings.

There may be other potential opportunities to lower costs under a co-op model that have not been included in the quantitative modeling; these are discussed in more detail in Task 1.6.1 *(Overview of the differences in how revenue requirement is calculated under each ownership model).* Replacing the current utility management structure to nimbler, and potentially more efficient, co-op entities could potentially lower certain overhead expenses related for instance to administration or IT infrastructure. A co-op may also be eligible for disaster relief assistance from the Federal Emergency Management Agency ("FEMA"). This means that the co-op would not pass on to the ratepayers the entire cost of recovery from natural disasters like hurricanes and volcanic activity to which Hawaii is vulnerable. Therefore, moving towards a co-op model on any island or county in Hawaii comes with a trade-off between a lighter and efficient structure for co-ops vs. economies of scale for the current IOU structure.

Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model)* discusses this in more detail.

Figure 27. Illustrative – estimated savings from federal tax exemption based on 2016 tax liabilities

($000s)	IOU	Co-op	Savings
35% Federal Tax Rate			
HECO	57,442	8,880	48,562
MECO	12,464	1,927	10,538
HELCO	11,673	1,804	9,868
HECO Companies Total	**81,579**	**12,611**	**68,968**
21% Federal Tax Rate			
HECO	38,017	8,880	29,137
MECO	8,249	1,927	6,323
HELCO	7,725	1,804	5,921
HECO Companies Total	**53,991**	**12,611**	**41,381**

ILLUSTRATIVE ONLY

Source: SNL; HECO-3203, DOCKET NO. 2016-0328.

Likewise, a move to any of the two SB models would require initial capex to set up the SB entity with the necessary infrastructure and operating costs. A transition to the SB model within the utility involves implementing ring-fencing mechanisms such as setting up separate work areas and information technology systems for the SB and additional security protocols for highly sensitive and confidential information relating to the SB's functions, to name a few. Also, some resources, such as human resources, legal, and accounting, would still be shared with the parent utility, under the SB within the utility. On the other hand, the SB model outside of the utility would incur additional expenses such as conducting annual audits and hiring of personnel that would typically have been shared with the parent company.

It is projected that the transition costs to set up an SB range from $2.3 million to $3.3 million – this includes the costs of stakeholder outreach and regulatory or legislative processes but does not include acquisition costs for a co-op or the capex to establish the SB offices.[107] This estimate is

[107] The transition costs for a co-op were informed by NRECA's technical assistance guides on the creation of co-ops.

based on the steps required, timeline, and projected costs of each step as summarized in Figure 25 and described in detail in Task 1.3.1 *(Identification of various steps, timeline, and).* An SB would incur its own operating expenses for system planning and procuring power from IPPs. It requires separate business premises from the rest of the utility, which necessitates additional rental costs for appropriate office space.

It is assumed that the transfer of some of the utility's responsibilities to an SB would lower the parent utility's current expenses for the planning department by half. The utility would continue to perform its own planning, and the costs related to this would be included in the utility's revenue requirements and passed on to ratepayers. Although the SB does collect fees to cover its operating costs, including from the IOU, these costs are ultimately passed on to ratepayers.

The primary benefit of an SB is a more level playing field between utilities and IPPs. It is assumed that the SB's independence in both planning and solicitations for power supply would lower purchased power costs by 3%. The 3% is based on the lower end of the range of efficiency gains found by several quantitative studies on the benefits of competition and unbundling. These studies are cited in more detail in Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model).*[108]

The upfront capital costs to set up an SB and ongoing annual operational expenses were estimated based on the reported costs of the Ontario Power Authority. The Project Team adjusted these costs for Hawaii to account for inflation and scale. These costs are summarized in Figure 28.

Figure 28. Estimated 2016 expenses under the SB model

($000s)	HECO	MECO	HELCO	KIUC
Initial Capex	3,140	514	913	257
SB outside the utility				
O&M	9,738	4,929	5,599	2,465
Office Rent	279	46	81	23
Audit	15	15	15	15
Total	10,032	4,990	5,695	2,502
Ring-fenced SB				
O&M	8,717	4,709	5,473	2,355
Office Rent	279	46	81	23
Incremental IOU earnings	238	38	71	0
Total	9,234	4,793	5,625	2,377

Source: LEI analysis.
Note: These numbers were initially estimated for a hypothetical SB if it had been operational in 2016 to evaluate potential savings. They were then escalated for inflation for subsequent analyses. They do not include the transition costs of the steps leading to physically setting up an SB.

[108] Some of the studies reviewed were: O'Connor, P. *Restructuring Recharged: The Superior Performance of Competitive Electricity Markets 2008 – 2016.* 2017; Fabrizio et al. *Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency.* 2007; Bushnell, J. & Wolfram, C. *Ownership Change, Incentives and Plant Efficiency: The Divestiture of US Electric Generation Plants.* 2005.

4.13 Financing mechanisms

IOUs usually finance capex through a combination of debt (short- and long-term) and equity (e.g., stock). Debt financing is when a firm obtains capital through the sale of debt instruments to investors, may they be individuals and/or institutions. Said individuals and/or institutions, in return, are promised the repayment of debt plus interest. Conversely, equity financing is when a firm obtains capital through the sale of shares, or essentially ownership interest. The sum of the cost of equity and debt financing represents a company's cost of capital, and the cost of capital represents the minimum returns a firm must make to satisfy all providers of capital.

Similar to an IOU, a co-op could finance capex through debt or equity. However, the sources and costs of acquiring capital are different for a co-op than for an IOU. The co-op entity's members may contribute equity to the purchase of assets, for instance. A co-op's margins in any year can be referred to as patronage capital, and each member's patronage capital account represents his/her portion of ownership in the co-op. Depending on the co-op's financial status, the co-op may return a proportion of the patronage capital to members as checks or bill credits, thereby considered as retired patronage capital. The remaining amount remains credited to members' accounts but is invested in the co-op, representing the equity capital provided by co-op members. Conversely, the co-op utility may choose to raise debt as rural electric co-ops have access to low-interest loans to fund acquisitions of other utilities through both public and private sources.

To finance the transition to the SB that is within the utility and its day-to-day operations, its revenue requirement would be combined with that of the utility and consequently recovered through electricity rates. The SB would thus be able to recover its costs related to power procurement and its operations.

In the case of an SB outside of the utility, a separate entity must be set-up that is not associated with the utility. To finance the day-to-day operations, the SB's revenue requirement would be recovered from fees assessed on consumers' electricity bills. These fees would need to be approved by the PUC. Alternatively, if set up as a government agency, the SB operations can be financed through funds appropriated by the legislature.

Task 1.6.5 *(Qualitative assessment of financing options)* provides an analysis of the potential financing options for each ownership model

4.14 Potential impact on the staffing needs of the PUC and DCA

The Project Team also looked at the effects of the change in the ownership model for the staffing needs of the PUC and the DCA.[109] Typical practices in other jurisdictions with the four ownership models were reviewed, and the oversight management and staffing needs of related State agencies and stakeholders under each model were assessed.

[109] Although there are several state agencies that interact with the electric utilities, the Project Team focused this Study on the PUC and DCA.

It is important to note that the roles and responsibilities of PUCs and DCAs vary significantly across jurisdictions. This is both due to functional roles as well as state energy policies such as the RPS. The scope of the study did not include a detailed staffing level assessment of Hawaii's PUC or DCA, and the relative comparisons should be assessed in that light. The assessments are done to develop an understanding of the upward or downward pressure on staffing requirements between the alternative ownership structures. Generally speaking, it could be observed that jurisdictions with more ambitious and active clean energy policies or initiatives tend to have more staff members but not necessarily higher staff-to customers ratios in relevant regulatory agencies.

Furthermore, the staffing needs and the salary levels are likely to remain stable or follow inflationary and/or GDP growth (similar to trends seen in the past) under the IOU model. For the co-op model, assuming reduced oversight of co-ops,[110] the staffing needs are expected to be lower by about 23% in the PUC and 21% in the DCA.[111] For the SB models, the staffing needs are generally higher by 10% in the PUC[112] (while the requirements in DCA remain unchanged) as the ownership transition requires more staff with specific technical expertise, increasing the budget for salaries (mainly to attract qualified staff for the new responsibilities).

There would likely be minimal changes in the management structure (or organizational chart) of the PUC and the DCA as the functional divisions will be needed regardless of the ownership model. Furthermore, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the electric utility's ownership model. Although the Hawaii PUC's mandate is limited to regulating the four electric utility companies, Hawaii's aggressive RPS, performance-based regulation, 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 ownership model selected.

Tasks 1.3.4/1.4.3 *(Assessment of how each ownership model impacts staffing of State agencies and stakeholders)* provides a more detailed discussion on the impact of the change of ownership model on staffing and management.

4.15 Potential impact on the penetration of DERs

DERs are resources that are interconnected to the electric grid at the distribution level, located close to the customers, and generally small in scale. DERs include distributed generation ("DG"), energy storage, demand response, energy efficiency ("EE"), and electric vehicles ("EV"). DERs offer several advantages; for example, they can improve grid reliability by co-locating generation and load, delaying or avoiding infrastructure investments, and offsetting emissions.

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[110] Currently, KIUC is under the authority of the Hawaii Public Utilities Commission, but as analyzed below, jurisdictions with many cooperatives are likely to have less oversight of cooperative utilities.

[111] Under the co-op model, the Project Team estimated the new number of positions in the PUC to be 50 ((65-50)/65 = 23%); for the DCA, the Project Team estimated the new numbers of positions to be 15 ((19-15)/19 = 21%).

[112] Under the SB models, the Project Team estimated the new staffing needs in the PUC will range from 65 to 70. An increase to 70 would represent an 8% increase.

A change in utility ownership models is generally not considered a key driver of DER adoption and deployment. Nevertheless, such a change could still have some impact on the penetration of DER because of variations among the models in terms of ease of access of the DERs to the system and the fair treatment of these assets.

Among the four ownership models reviewed, the two SB models and to an extent the co-op would likely be the most beneficial for increased penetration of DERs, more specifically DG and energy storage. In the case of the SB models, the SB's independence ensures that it would not have any bias with regards to the procurement or facilitation of interconnections of DG and energy storage resources. Likewise, a co-op (which is governed by its members) generally would be motivated to implement goals that would be beneficial not only to the utility but also consistent with the underlying policy objectives of its jurisdiction.[113] It is anticipated that there will be more energy storage under the co-op model, holding everything else constant, because it may be easier for the co-op to forge partnerships with landowners, who are also members of the co-op. Moreover, it is projected that there will be more energy efficiency programs under a co-op model to help members-customers to participate in conserving energy and saving on their electric bills. Meanwhile, under the IOU ownership model, there is likely a positive impact on DR programs as well as EV deployment because it is presumed that an IOU would have more resources and staff available to help implement these programs, as well as access to capital for the required investments (for EVs). Figure 29 illustrates the impact of the change in the ownership model on the penetration of DERs as well as energy security and reliability.

Figure 29. Impact of change of ownership model on the penetration of DERs and the energy security and reliability

Alternative regulatory model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to IOU	—	—	↑	—	↑	—
Move to co-op	↑	↑	↓	↑	—	—
Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
Move to Single Buyer (outside the utility)	↑	↑	—	—	—	—

Furthermore, the change in utility ownership would not impact energy security and reliability. Policies and regulations are already in place, ensuring that the achievement of RPS targets will not cause any issue with system security. Regardless of the ownership type, there are

[113] KIUC has had lower penetration of DERs compared to the HECO Companies. Whether a co-op would develop more DERs is subject to its costs and benefits compared with grid-scale renewables, status of renewable integration in the system, and many other factors.

requirements that the utilities need to fulfill and performance standards that they need to comply with.

Finally, higher DER penetration and deployment will be achievable under any ownership model provided that appropriate regulatory structures and incentives are put in place.

Task 1.5.1 *(Estimated potential for each model to increase distributed energy resources)* provides a more detailed discussion on the potential impact on the DERs of a change in utility ownership models.

4.16 Potential impact on the residential electricity rates

Based on the assumptions within the report, a change in ownership model could benefit residential ratepayers in Maui and Honolulu counties but may not in Hawaii and Kauai counties. In the three counties with an incumbent IOU, there are opportunities for the lowering of certain categories of costs through a change in ownership model, but there are also costs of transition to consider. Both opportunities and transition costs are higher under the co-op model. In Kauai County, the SB model is not expected to lower costs, but it can provide potential non-financial benefits in terms of reducing the potential for conflicts of interest in utility capital expenditure practices, as well as promoting state policies such as diversification of energy resources.

Meanwhile, a change to the co-op model in Honolulu and Hawaii counties is projected to increase average rates between 2018 and 2045 compared with rates in the Status Quo IOU model. This increase is driven primarily by the cost of purchasing the assets of the incumbent utility, assumed to be undertaken through 100% debt financing. As a result, the co-op model is expected to have a significantly higher debt burden (which includes interest payments). Since revenue requirements for co-ops are determined using the TIER-based approach, higher interest payments directly translate into higher rates. Furthermore, the need to raise additional debt financing to cover planned capex also drives higher rates under the co-op model than under the status quo. For revenue requirement modeling purposes, the Project Team assumed that the planned capex out to 2045 would be the same under all ownership models, based on the investment plan laid out in the HECO Companies' PSIP. While the Project Team acknowledges that a change in ownership model could potentially result in a different investment plan, such changes are impossible to predict even with extensive economic and technical analyses which were outside the scope of the present study. As such, to provide a comparable basis for the analysis of all ownership models, the Project Team opted to use publicly available data.

In the case of Honolulu and Hawaii counties, the costs of servicing the debt incurred for acquisition of the incumbent utility's assets together with the additional financing required for planned capex are expected to outweigh the cost reductions resulting from the move to a co-op model. These cost reductions can include lower projected expenses in contracting future power supply from IPPs, exemption from federal income taxes, and possibly lower operating expenses from a more lightweight structure. Although co-ops can generally secure debt financing at a lower cost than IOUs, the Project Team's analysis indicates that the benefit to ratepayers from co-ops' access to lower cost capital may not outweigh the increase in debt due to acquisition costs.

However, in Maui County, the acquisition costs and higher debt service burden based on the assumptions within would not completely negate the cost savings from the transition to a co-op model. In such a scenario, the rates on average would be lower between 2018 and 2045 under the co-op model than under the IOU model. Notably, the Project Team expects that the costs for a co-op to acquire MECO's assets (estimated at $675 million) would be much lower than in Oahu ($3.25 billion for HECO) and Hawaii island ($761 million for HELCO).[114] Furthermore, future opportunities to lower costs are higher in Maui County as compared to Hawaii County because HELCO is already procuring a higher portion of its supply from renewable generation IPPs through long-term contracts.

It is important to note that throughout the forecast horizon, the forecasted rates under the three highly ranked ownership models for individual years could be higher or lower than rates under the Status Quo. Figure 30 summarizes the expected impacts on average rates between 2018 and 2045 under alternative ownership models when compared to rates under the Status Quo. Task 1.6.4. *(Matrix comparing system average retail rates under each ownership model)* provides a more detailed discussion on the projected average electricity rates by customer type from 2018 to 2045.[115]

Figure 30. Average impact of a change in ownership model on residential rates relative to the Status Quo (2018 – 2045)

Change of the Ownership Model	Honolulu County	Hawaii County	Maui County	Kauai County
Move to a co-op model	5.3%	8.2%	-1.8%	
Move to a Single Buyer within the utility model	-0.7%	0.3%	-1.3%	1.0%
Move to a Single Buyer outside the utility model	-0.8%	0.3%	-1.3%	1.0%
Move to an IOU model				6.7%

On the other hand, the SB models are expected to lower average rates between 2018 and 2045 relative to the rates under status quo IOU in both Honolulu and Maui counties. It is anticipated that SB models deliver financial benefits to ratepayers by lowering the cost of the procurement of generation through increased competition such that the projected expenses of future power supply contracts with IPPs would be lower by 3% compared with expenses under the status quo. The SB models would deliver net economic benefits to ratepayers if the reductions in power supply costs outweigh the operating costs of an SB. As described in Task 1.6.1 *(Overview of the differences in how revenue requirement is calculated under each ownership model),* the SB models are not projected to financially benefit HELCO's ratepayers as much as the other models because the

[114] The Project Team applied several valuation approaches, including discounted cash flow, trading comparables, and comparative transactions. The Project Team used the results of the comparative transactions analyses, based on a review of 9 precedent transactions involving comparable electric utilities. Note that these examples were with a willing seller.

[115] To derive the projected average retail rates under each ownership model up to 2045, a revenue requirements model was created for each ownership model and for each county. For the ownership models, a total of 16 revenue requirements models was created. Please refer to the following memos for additional information on the assumptions used and the results of the revenue requirements: Task 1.4.2 *(Economic evaluation of ownership and operation of each ownership model)* and Task 1.6.3 *(Estimated revenue requirements under each ownership model through 2045).*

utility's purchased power from future IPPs will be proportionally smaller than in the cases of HECO and MECO.

A change in ownership model from the Status Quo co-op in Kauai County is expected to increase rates on average between 2018 and 2045. A transition to an IOU model would increase the financing costs since IOUs have a higher weighted average cost of capital based on their cost of debt and their cost of equity. Likewise, the SB models would result in higher costs to KIUC's ratepayers because of the incremental expenses associated with SB operations but without direct financial benefits from lower purchased power costs, as the co-op model by nature does not reward capital expenditures in the same manner as with IOUs and as such, the SB would not necessarily purchase power at a cost lower than the co-op would. Task 1.4.2 (*Economic evaluation of ownership and operation of each ownership model*) provides a more detailed discussion on this subject.

Figure 31. Average impact on residential rates relative to the Status Quo (2018 – 2045) in Maui County – comparison of ownership change by the island and by county

Maui County – county-wide ownership model change	Maui	Lanai	Molokai
Move to a co-op model	-1.8%	-1.4%	-2.5%
Move to a Single Buyer within the utility model	-1.3%	0.8%	1.2%
Move to a Single Buyer outside the utility model	-1.3%	0.8%	1.2%
Maui County – ownership model change by island	**Maui**	**Lanai**	**Molokai**
Move to a co-op model	-1.8%	-1.4%	-2.5%
Move to a Single Buyer within the utility model	-1.3%	29.6%	29.1%
Move to a Single Buyer outside the utility model	-1.3%	31.2%	30.3%

Two approaches were evaluated with regards to a change in ownership structure for Maui County. The first approach analyzed a change in ownership model on an island-by-island basis, whereas the second approach assumed the ownership model is the same in a county-wide basis. If transitioning to a co-op model, both approaches result in identical outcomes because MECO's costs were allocated among the three islands in the same proportion under both methods. For the two SB models, the county-wide ownership change assumes that one SB is established for Maui County, and the associated costs are allocated to all three islands on a pro rata of their load. It is worth noting that if Lanai or Molokai were to change to a co-op and lose the economies of scale in shared administration and operations and maintenance costs from being coupled with Maui island customers, this could significantly increase the cost of implementing a co-op ownership model on Lanai or Molokai.

The ownership change in an island-by-island basis analysis assumes that an SB is established on each island. Creating a separate SB in Lanai and Molokai is projected to increase electricity rates in these islands because of the magnitude of fixed costs associated with the establishment and operation of an SB relative to the overall utility expenses in these islands. The average impact on rates between 2018 and 2045 under both approaches are summarized in Figure 31.

In summary, the analysis shows that any of the recommended ownership models could lower electricity rates on Maui island while a co-op model could provide lower rates in Lanai and Molokai islands. The co-op model would be less expensive than other models on Lanai and Molokai because the savings from future power procurement on those islands, as compared to the Status Quo, would outweigh the cost of transitioning to the new ownership model, without the additional costs associated with setting up a new SB entity.

5 Potential regulatory models

5.1 Description of the potential regulatory models

The Project Team initially reviewed four families of regulatory models, in addition to the status quo COS approach. These models are not mutually exclusive, and some of them and/or their features could co-exist. These regulatory structures were determined based on legislative mandates, the emerging market trends in high renewables penetration jurisdictions, current state goals, and high-level evaluation of various additional potential regulatory arrangements. These models include the HERA model, independent system operator, distribution-focused regulatory model, and performance-based regulation ("PBR"), which are discussed in the subsections below. Note that PBR includes a wide spectrum of possible measures and that the Project Team reviewed several possible constructs within the PBR framework. Task 2.1.1. *(Summary comparison of Regulatory Models from Hawaii's perspective)* provides a more detailed discussion on these potential regulatory models.

5.1.1 Status Quo with increased oversight (or the HERA model)

The HERA model is assumed to be implemented as an addition to the current COS framework, referred to herein as the "status quo with increased oversight model" or "HERA model." HERA is a concept established by state legislation (Act 166) in 2012 to enforce reliability standards and interconnection requirements, as determined by the PUC. The Act authorizes the PUC to create the HERA entity, although the PUC has not created HERA 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 be transferred to HERA in this regulatory model.

North American Electric Reliability Corporation ("NERC")

The North American Electric Reliability Corporation ("NERC") is an entity currently operating on the US mainland in a somewhat comparable role to what was envisioned for HERA. NERC is the electric reliability organization for North America and responsible for developing and enforcing mandatory electric reliability standards as overseen by FERC. There are also other similar features between HERA and NERC. First, both are not-for-profit regulatory authorities. 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. Finally, HERA and NERC are subject to oversight by a regulatory body (e.g., PUC for HERA and FERC for NERC).

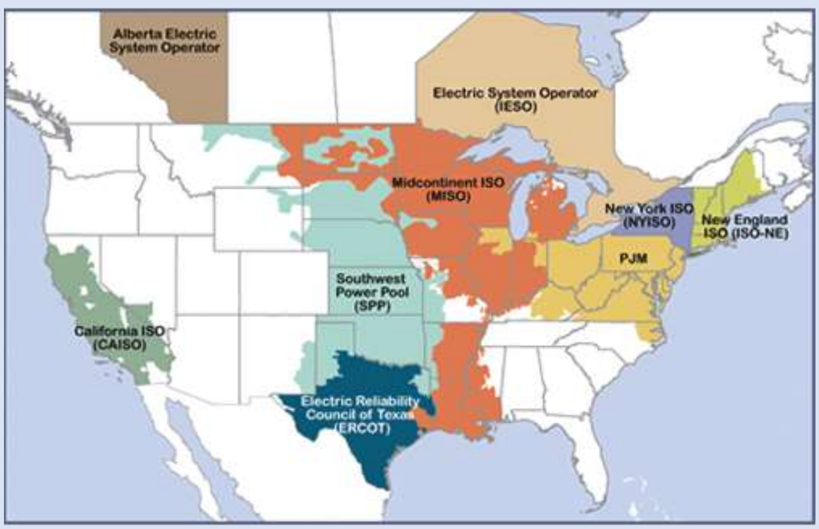
Moreover, the Project Team envisioned a Light HERA as a variation to this model. A Light HERA could be designed as an ombudsman; an appeals body focused on reliability and interconnection. It would have the technical capability to set target timeframes and standard models for calculating interconnection costs, which could be relied upon to settle customer challenges to utility interconnection behavior or lack of transparency about hosting capacity. In this model, HERA could only investigate after the customer has exhausted all the utility's internal appeals processes. HERA could also propose actions for the PUC to take if it finds that the utility has been behaving arbitrarily. However, the intent is that a referral to HERA would serve as an incentive for the utility and its customer to settle differences.

5.1.2 Independent System Operator

An ISO or a regional transmission organization ("RTO") is an independent, membership-based, non-profit organization that ensures electric system reliability and uses bid-based markets to determine economic dispatch for wholesale electric power.[116] The concept of an ISO came from FERC's Orders Nos. 888/889 and subsequently the concept of RTO was introduced in Order No. 2000. 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,[117] encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America.

ISO/RTOs in North America

There are currently nine ISOs/RTOs in North America as shown on the map below. These include the Alberta's AESO and Ontario's IESO in Canada, as well as California's CAISO, the Southwest Power Pool, Texas's ERCOT, the Midcontinent ISO, the PJM Interconnection, New York's NYISO, and New England's ISO-NE.



An ISO structure typically aims to ensure reliability, which requires collaboration on the part of the ISO, transmission owners, and electricity utilities. This is ensured through:

- coordination of existing system components and processes to guarantee delivery of electricity upon demand;
- cooperation in monitoring and coordinating generation and transmission;

[116] EIA. *Today in Energy*. <https://www.eia.gov/todayinenergy/detail.php?id=790>

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

- 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.

Under the ISO model, utilities continue to own and maintain the transmission and distribution system. However, utilities yield their functions of system planning, generation dispatch, and day-to-day operations of the bulk power system 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 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 transactions, significant capital expenditure, service quality, and rates would remain the same. However, the tasks of ensuring 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.

5.1.3 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") process. Much like Hawaii State, New York State enacted policies to increase the use of clean energy and customer participation in the electricity sector. Its REV initiative is fundamentally altering 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 implementations for a distribution-focused regulatory model that could be considered in the State of Hawaii. The first implementation assumes that the distribution infrastructure is still owned and operated by the incumbent utilities. This implementation is similar to New York's REV, where the distribution utility assumes the role of Distributed System Platform Provider ("DSPP"). The DSPP's new role, as envisioned by the New York regulator, would include "planning and designing its distribution system to be able to integrate DER as a primary means of meeting system needs."[118] Under REV, the DSPP would be required to "*use localized, automated systems to balance production and load in real time while integrating a variety of DERs, such as intermittent generation resources and energy storage technologies*."[119] Moreover, the

[118] 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.

[119] Ibid. Page 13.

DSPP would also be 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.*"[120] However, this approach requires corresponding incentives to ensure that the utilities act in a way that supports the desired outcomes, such as allowing third-party access to the grid, making data available, etc.

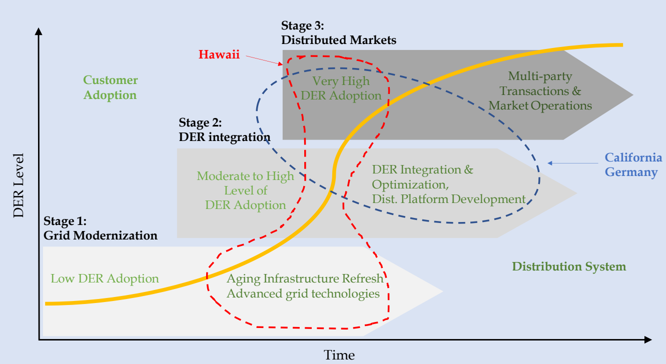
Examples of jurisdictions in the various stages of DER adoption

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:

- *Stage 1: Grid modernization* – 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.
- *Stage 2: DER integration* – DER adoption levels increase so that they are at the threshold level that will require enhanced functional capabilities to ensure reliable system operation.
- *Stage 3: Distributed markets* – a combination of very high DER adoption, enabling system technology investment and policy decisions to allow for the creation of distribution-level energy markets and multi-sided transactions.

As illustrated below, 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 33 illustrates this adoption process as developed by DeMartini and Kristov in their report for Lawrence Berkeley National Lab's "Future Electricity Regulation" series.

Figure 32. 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.

[120] Ibid. Page 14 - 15.

The second implementation assumes that the distribution infrastructure is still owned by the utilities, but operated by an outside entity. This external entity, called the IGO, would be under the purview of the PUC, and operate and plan for the distribution system. The IGO is expected to execute the day-to-day operations of the grid and be responsible for planning for upgrades to the system. On the other hand, the utilities would maintain and make the required investments for the distribution assets. The utilities would also participate in the planning and operational process of the IGO. This is the same relationship that an ISO would have with transmission owners. However, due to the small size of Hawaii's bulk power system, the IGO would function as the system operator at both transmission and distribution levels. This would also allow the IGO to coordinate the use of utility-scale resources and DERs more efficiently. 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.

5.1.4 Performance-Based Regulation

The current COS regulation may no longer provide the incentives that would encourage the utilities to meet the challenges related to the penetration of renewable resources and distributed energy. With these transformations, the performance expected from electric utilities would also need to change. The performance and role expected of the utilities have been expanded to cover other aspects of the business.[121] Through the *Staff Proposal for Updated Performance-Based Regulations* under Docket 2018-0088, the PUC Staff has identified prioritized outcomes. These include enhancing customer experience, improving utility performance, and advancing societal outcomes.[122]

PBR, compared with traditional COS, can induce desirable changes to utility behavior. PBR could 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 33).

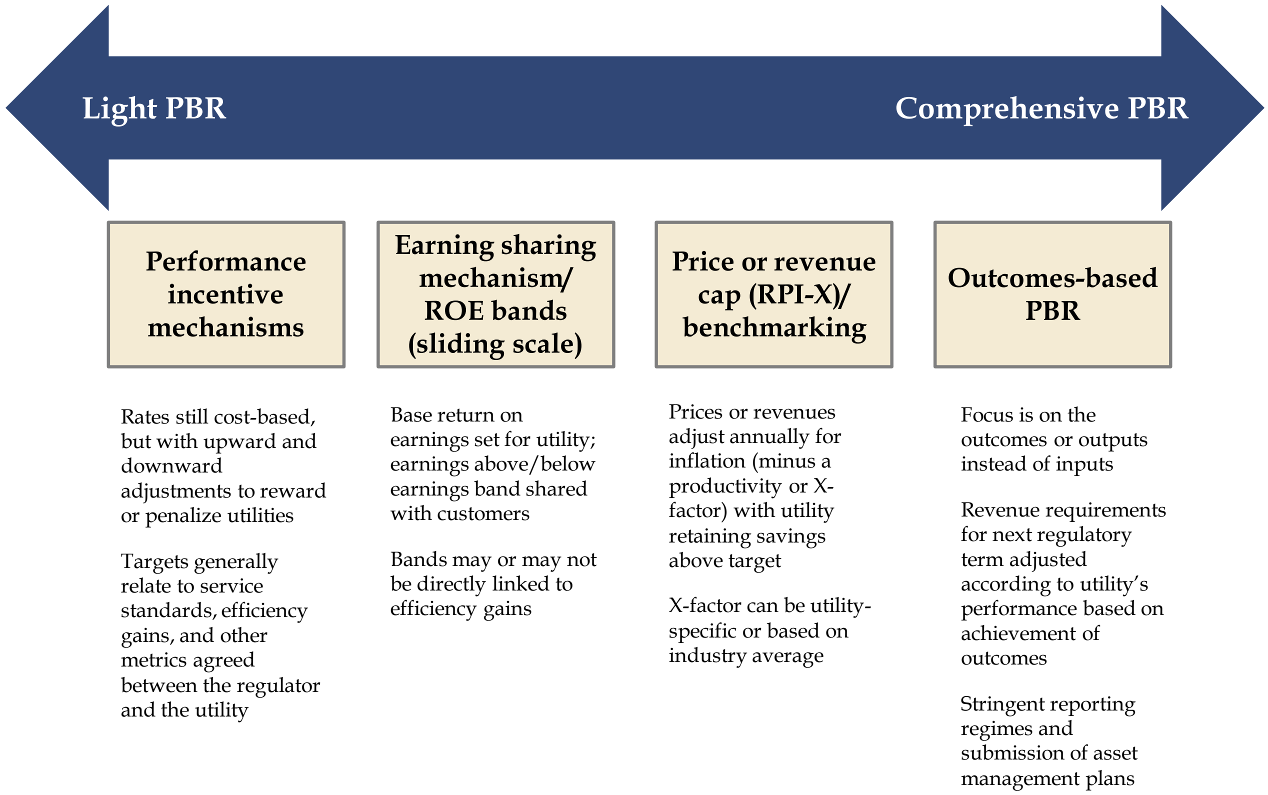
A model which could be thought of as Light PBR includes mechanisms such as PIM and an ESM where payments to the utilities are adjusted based on their level of performance vis-à-vis the target outcomes. The "medium" form of PBR mechanisms would include a rate cap where either the rates or the revenue is capped for the regulatory period. This cap helps promote efficiency as the mechanism tends to change the link between a utility's rates and its costs and improves efficiency. Task 2.2.1 provides a more detailed discussion on Light PBR.

At the end of the continuum is the Outcomes-Based PBR, which is the newest form of PBR where the focus is on the outcomes rather than the inputs to the revenue requirement calculations.

[121] 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) 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.

[122] Hawaii PUC. *Staff Proposal for Updated Performance-based Regulation*. February 7, 2019. Page 17.

Figure 33. Continuum on PBR regulation (from "light" to "comprehensive" key mechanisms)



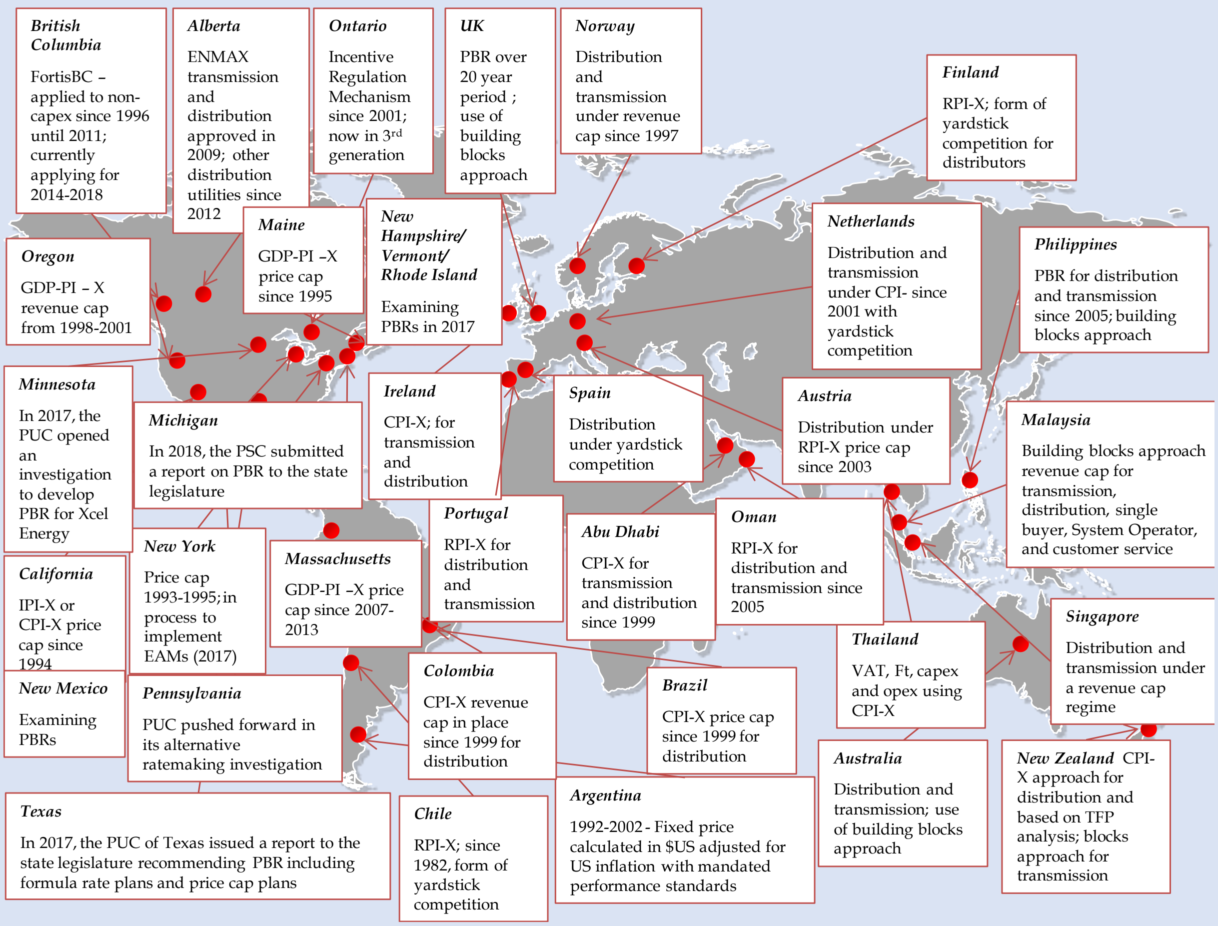
The "correct" implementation of PBR depends on the needs and values of the particular jurisdiction. Generally, the choice of a light versus a comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners. The "light" and "medium" forms of PBR can be considered as a "stepping stone" towards the comprehensive PBR mechanism. Section 5.3.4 provides more information about the benefit of PBR.

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.

Task 2.1.1 *(Summary comparison of Regulatory Models)* provides a more detailed discussion of these regulatory models.

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

PBR regimes exist in multiple jurisdictions throughout the world as shown in the map below. 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. 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.



5.2 Potential PBR options for Hawaii

Three PBR options—Light PBR, Conventional PBR, and Outcomes-based PBR—were considered in the Study for Hawaii, based on the goals of the Hawaii Ratepayer Protection Act, which established "*performance incentives and penalty mechanisms that 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,*"[123] and PUC's aspirations of "*greater cost control and reduced rate volatility,*

[123] HRS §269.

efficient investment and allocation of resources, fair distribution of risks and fulfillment of state policy goals."[124] Figure 34 shows the key components of each PBR option and the subsections below discuss in detail these three PBR options.

Figure 34. Key components of each proposed PBR option for Hawaii

	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

SAIDI: System Average Interruption Duration Index *SAIFI: System Average Interruption Frequency Index*

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

The PBR regime in the succeeding regulatory periods would evolve and 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 regulatory environment.

5.2.1 Light PBR

Light PBR builds upon the existing regulatory model and would expand the current set of PIMs to include other performance metrics, facilitating more effective achievement of the state's energy goals. Revenue requirements would be determined using the COS approach, with the utility subject to penalties and rewards for achieving or missing the targets. The expanded set of PIMs would not replace but work in conjunction with all other current performance and customer service standards set by the PUC, together with any guaranteed minimum service levels standards. The regulatory term would be the same as the current general rate case cycle of three (3) years. Finally, Light PBR would include the current ESM where earnings above the threshold would be shared with the customers.

5.2.2 Conventional PBR

Conventional PBR would use an indexation formula to determine the revenue requirements of the utilities. The indexation formula is based on inflation less a productivity factor. The inflation factor provides a mechanism through which the utility's revenues may be adjusted annually to reflect expected 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 revenue requirements calculation would utilize a revenue cap instead of a price cap. 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 considering its policies of encouraging conservation, demand response programs or energy efficiency because it removes the conflict between regulation and policy goals to a significant degree. 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 is also the case for a price cap) would incentivize utilities to minimize overall costs since revenues are fixed and they could generate more profits by operating more efficiently and spending prudently.

There would also be an ESM under Conventional PBR, although larger and symmetrical deadband and sharing percentages would be adopted. The percentage share between the utility and consumers would be the same (e.g., 50% for utility and 50% for customers) and the deadband for gains and losses would be the same between the utility and consumers but larger (e.g., +/-200 basis points). Having a larger deadband under this model is necessary to provide the utilities the opportunity to earn a higher return given the higher risk associated with the indexing formula in determining the rates. The ESM is aligned with the PUC's aim of having a mechanism that results in *"fair distribution of risks between utilities and customers."*[125]

Moreover, the PUC's objective is to develop a mechanism that results in *"efficient investment and allocation of resources regardless of classification as capital or operating expenses."*[126] The model would, therefore, include a total expenditure approach ("totex approach"), where there is no distinction between capital and operating expenditures. In this way, the utilities would be expected to use the most cost-effective solution to achieve an outcome. Moreover, it will eliminate the issue of determining the boundaries between operating expenditures ("opex") and capex, which entails a significant amount of time and regulatory costs.

Lastly, the Conventional PBR model would also feature the same regulatory term (3 years) and a set of PIMs as the Light PBR model.

5.2.3 Outcomes-based PBR

Outcomes-based PBR, which is similar to the UK's RIIO model ("Revenue=Incentives+Innovation+Outputs"), would focus on the outcomes related to enhancing customer experience, improving utility performance, achieving public policy goals, and attaining healthy financial performance. Based on these outcomes, the performance categories and measures for each group would be determined. Unlike Light PBR, Outcomes-based PBR would require a more comprehensive set 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 the utility 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

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

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

spent. A large disparity between actual expenditures and those reflected in the plans could trigger a Commission investigation.

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. However, in contrast to Conventional PBR, the rates under an Outcomes-based PBR model would be based on a five-year forecast of the utility's revenue requirement and sales volumes. This means that unlike Conventional PBR where the rate for the next two years of the regulatory period would increase according to an indexing formula,[127] the revenue requirements would already be determined for the next five years based on the utility's revenue and sales forecasts. Moreover, a longer regulatory period (preferably five years) would be more appropriate under Outcomes-based PBR to better align the rate setting with 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.

Generally, a building blocks approach is used to forecast the revenues in this model which 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, targets, and necessary capital investment. In other words, unlike under the conventional PBR where productivity (or the "X") of the I-X formula is applied to otherwise COS-based rates, the productivity improvements under the building blocks approach are embedded in the forecasts. Therefore, under a building blocks approach, there is a need for extensive benchmarking analysis to set efficient costs. These total costs would then be added together—hence, "built up"—to determine an allowed revenue requirement for the utility based on estimates of the utility's expected capital and operating costs, and return on rate base assets.

Finally, similar to the Conventional PBR, the symmetrical ESM and totex approach would also be incorporated in this option. Task 2.2.1 (*Summary comparison of Regulatory Models from Hawaii's perspective*) provides a more detailed discussion on the potential PBR mechanisms for the State of Hawaii.

5.3 Advantages and drawbacks of each regulatory model

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. However, there are several 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

[127] The first year rate of the regulatory term is the going-in rate which is determined through COS as discussed in Section 3.3.1. 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.

regards to timeline on issuing regulatory decisions, and reduce complexity and cost of regulation and regulatory compliance.

The advantages and drawbacks of each model are summarized in Figure 35 and further discussed in the following subsections. Task 2.2.1 *(High-level evaluation of the regulatory models relative to the State's goals)* provides a detailed discussion of the advantages and drawbacks of each regulatory model.

Figure 35. Summary of advantages and disadvantages of each regulatory model

	Pros	Cons
HERA model	• 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 grid operator	• 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	• High level of stakeholder engagement required to initiate • Careful market design needed to mitigate implementation risk • Additional costs required in terms of implementation costs
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	• 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	• 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 to design the PBR • Requires lengthy stakeholder efforts
Lighter PUC regulation	• A reduction in regulations would reduce costs for both KIUC and the PUC	• Could result in the state's inability to ensure co-ops comply with state policy goals

5.3.1 HERA model

Having a separate entity from the PUC that performs oversight and monitoring of interconnection and reliability standards would allow for 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 RPS targets for the State.

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

Moreover, as a separate entity dedicated to reliability standards monitoring and enforcement, HERA 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.[128] The study found that an independent organization such as HERA could be beneficial to the State, particularly when it comes to overseeing the planning, reliability standards, and interconnection processes.

A variant of this model, a Light HERA, could be designed to improve the 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.

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 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.[129]

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[128] 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.

[129] 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).

Another potential challenge in the establishment of a HERA entity is the required funding—which would ultimately fall on ratepayers.[130] 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.[131]

5.3.2 IGO

The main benefits of an IGO 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. This model would operate similarly to ISOs on the mainland US but would also have control over the distribution grid given the relatively small scale of the state's electric grids.

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.[132] 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.[133]

Finally, an IGO model reduces conflicts of interest. Transferring the operations of the transmission system to an IGO 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 for the maintenance of reliability and resource planning. 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 IGO and approved by the PUC. The IGO's independence can address the capex bias that IOUs have in the current regulatory model.

Admittedly, the IGO 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

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[130] 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).

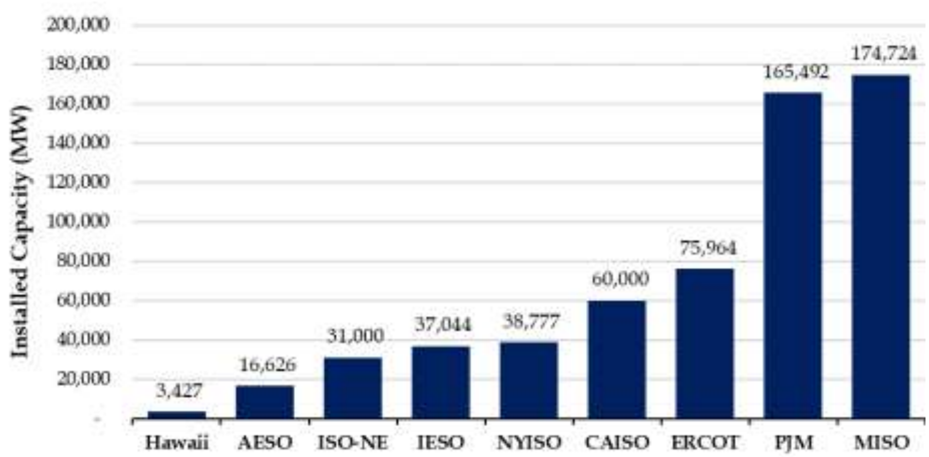
[131] Ibid.

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

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

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.[134] 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).[135] 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 IGO on a per capita or a per kWh basis (Figure 36).

Figure 36. 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 earlier, 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.[136] Most of the electric grid operates on lower voltage—13.5 kV to 69 kV; only Honolulu County operates

[134] 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, the National Interconnected System and the Baja California Sur Electric System. These three markets are monitored by the National Center for Energy Control (Centro Nacional de Control de Energía), all referred to as the Mexican Wholesale Electricity Market, 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.)

[135] 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.

[136] Task 1.1.2 memo.

higher voltage lines at 138 kV. Higher voltage distribution lines operate at 4 kV and 12 kV.[137] Therefore, the distinction between transmission and distribution components of the power delivery system in Hawaii is not as large or as distinct as on the mainland US.

Furthermore, as several, aging fossil fuel-fired power plants retire, they are being/would 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 an independent distribution system operator ("IDSO") are likely to have more overlap than differences in Hawaii.

Finally, IGO 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.[138]

5.3.3 DSPP model

The DSPP model has the potential to lower costs for consumers who, with appropriate incentives, will tend to reduce consumption from the grid during peak hours by optimizing DER solutions such as storage as well as benefiting from efficiency gains from the 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.[139] Benefits from improved coordination may include a reduction in line losses, which can potentially link to a reduction in surplus procurement of generation.

The DSPP model also provides wider grid access for behind-the-meter generation resources or DG. Currently, DG resources in Hawaii are predominantly rooftop solar photovoltaic ("PV") panels. Increasing use of battery-backed rooftop solar energy systems may occur 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

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

138 Joskow, P. *Lessons Learned from Electricity Market Liberalization.* The Energy Journal. 2008.

139 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)

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, helping to avoid or defer costly infrastructure upgrades.

Notably, the DSPP 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[140] 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.

The distribution regulatory model would require substantial enhanced functional capabilities from the distribution utilities while the complex grid infrastructure required to facilitate it may require high-cost investments.[141] This would also need 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 "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.[142]

To compound these risks, there are not many precedents; therefore, few best practices to learn from. 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

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140 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.

141 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.)

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

players entering the DER landscape and the rapidity of changes in technologies and customer demands.[143]

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 IDSO 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.

5.3.4 PBR

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.[144] A well-designed multi-year PBR with well-defined mitigation measures may also reduce regulatory risk on the utility, lowering its cost of debt and, ultimately, lowering costs to consumers.

Moreover, utilities are encouraged to operate more efficiently so they can achieve or surpass 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.[145] 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 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."[146] In fact, "since privatization, allowed revenues have declined by 60% in electricity distribution and

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[143] Ibid.

[144] 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.)

[145] 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.

[146] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. January 20, 2010. P. 50.

30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization."[147]

Efficiency gains from PBR mechanisms can be shared with customers through ESM. An ESM can also lower costs to consumers and ensures effective customer participation in a company's financial performance.[148] As discussed in Section 3.3.1, an ESM has been implemented in Hawaii along with the RAM since 2011, as part of the Revenue Decoupling Mechanism approved by the PUC.[149]

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. For instance, 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."[150] With performance standards in place under a PBR regime, distribution line losses may also improve.

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.[151] 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.

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 stakeholder 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.

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

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147 Ibid.

148 Sappington, David et al. *The State of Performance-Based Regulation in the U.S. Electric Utility Industry.* 2001. The Electricity Journal. P. 71-79.

149 Hawaii PUC. *RAM Legal Notice.* March 31, 2011. <https://puc.hawaii.gov/wp-content/uploads/2013/06/20110427-RAM-legal-ad.pdf>

150 Ibid.

151 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).

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 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.[152] Poor forecasting on the side of utilities can also lead to potential additional costs and/or penalties affecting their bottom line.

In summary, 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 higher risk to both 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.

5.4 Similarities and differences of the regulatory models

Each of the regulatory models discussed previously represents a different approach to the regulation of the State's power sector. Some of these regulatory models (such as the HERA, ISO, and distribution-focused regulatory models) require delegating some of the responsibilities of the PUC to an independent entity while others such as PBR would require a change in utility oversight from the PUC. These regulatory models were reviewed across three key parameters to ensure coherence and consistency. An overview of the analysis is shown in Figure 37.

Utility's role across the value chain

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. Under the HERA model, the existing regulatory model is augmented with the creation of HERA. The utilities will maintain their current roles across the electricity supply value chain. However, the utilities will be required to meet reliability and open access requirements under the oversight of HERA.

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 ownership of the distribution system. Under the distribution-focused regulatory model, the utilities facilitate the integration of DERs into the grid and are encouraged to provide DSP services. In this regulatory model, the Commission may also mandate

[152] 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.

the creation of an IDSO, which would perform the same duties as an ISO essentially but focused on the distribution-level system.

Figure 37. Comparison of characteristics 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 incentives					
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	

*: In some variations of the PBR framework, the typical definition of ratebase representing capital expenditures is replaced with an approach allowing utility to earn returns on total expenditures (operating + capital expenditures)

Note: "X" indicates that the feature is present in the model.

Regulatory model impact on utility incentives

Under all the selected regulatory models except for PBR, most or all of the sectors of the value chain will still rely on a rate base or COS approach to determine revenue requirements. In this model, there is an inherent bias for the utility to spend more on capital infrastructure instead of operations and maintenance to increase returns for shareholders. Under the proposed PBR mechanisms, this bias would be eliminated. However, the PBR model can still be implemented in conjunction with other proposed regulatory models and does not need to be a stand-alone option.

Oversight and monitoring

The role of the PUC would change slightly under the HERA model. More specifically, the HERA entity, which will still answer to the PUC, would oversee reliability and grid access functions. 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. In addition to its current responsibilities, PBR requires the PUC to develop new

PBR mechanisms and determine targets and metrics for assessing the utilities' performance (under the new framework) and from there, create a system of rewards and penalties. Once the PBR mechanism is in place, the PUC must monitor the performance of utilities vis-à-vis the set targets and outcomes.

5.5 Evaluation of the regulatory models relative to state goals

Similar to the ownership models, the Project Team evaluated alternative regulatory models with respect to the policy objectives established by House Bill 1700 (Act 124) of 2016 listed in the text box below.

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 (Act 124) Relating to the State Budget

In its qualitative analysis of the regulatory models, the Project Team relied on the same six major criteria that were used to assess the identified ownership models. The relationship between the four policy objectives and the evaluation criteria was shown earlier in Figure 19. The six major criteria are:

1. ***ability to meet state energy goals;***
2. ***maximize consumer cost savings;***
3. ***enable a competitive distribution system;***
4. ***address conflicts of interest;***
5. ***align stakeholder interests; and***
6. ***assess transition costs.***

Ability to meet state energy goals

As mentioned earlier, the ability to meet state energy goals is explicitly listed as one of the four guiding principles and is a criterion which can be qualitatively assessed. 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 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.

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. 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") programs and more recently with the Smart Export and CGS+ programs.[153]

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.[154] 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 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

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[153] 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).

[154] Hawaii Senate Bill 2787 (2012).

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.

Maximize consumer cost savings[155]

As discussed earlier, maximizing customer cost savings is also one of the four major criteria and can be assessed from both a qualitative and quantitative perspective. 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.[156] 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 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. 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:"[157]

- 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.

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155 The consumer cost savings considered in this section exclude consideration of implementation costs, which are treated separately.

156 EIA. *Electric Power Annual 2016.* Revised May 2018.

157 Hawaii PUC. *Docket No. 2018-0088 Instituting a Proceeding to Investigate Performance-Based Regulation.* Order issued and effective April 18, 2018. page 52.

An ISO model can also lower the 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 could increase for utilities in a HERA model, as they will have to monitor and track various metrics on reliability and grid access. Furthermore, the HERA entity 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.

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.

Enable a competitive distribution system

Enabling a competitive distribution system is the third guiding principle and can be assessed on a qualitative basis. A competitive distribution system is one "in which independent agents can trade and combine evolving services to meet customer and grid needs."[158] 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 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 because of 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 many DERs can be integrated into a distribution feeder to better optimize grid assets in real-

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

time.[159] 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. 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[160] are integrated into planning without impacting reliability.

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.[161] Utilities in markets with an ISO have begun to deploy DERs as a non-transmission alternative to defer or even replace the need for transmission upgrades. The independence of ISOs is critical 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 with 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-Wire Alternative ("NWA") projects.[162] Incorporating Earnings Adjustment Mechanisms ("EAM") in the PBR framework can be favorable for a competitive distribution system because utilities have incentives to increase participation of third-party

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159 "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>

160 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.

161 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>)

162 "Innovation Opportunities." *REV Connect*, Accessed on May 17, 2018. <nyrevconnect.com/innovation-opportunities/>.

service providers. 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. 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).[163] If a similar mechanism is instituted in Hawaii, utilities would have a stronger incentive in facilitating the growth of distribution-level markets than solely under a PBR model.

Address conflicts of interest

Addressing conflicts of interest is the fourth guiding principles and can be evaluated on a qualitative basis. 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. 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 also help address utilities' potential conflict of interest against IPPs and DERs, for example, by separating some 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.

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[163] Ibid.

Align stakeholder interests

Aligning stakeholder interests focuses on whether all stakeholder (PUC, CA, Legislature, Utility, and Consumers) incentives are aligned, rather than whether conflicts can be resolved.

The status quo model is, again, the least favorable because shareholder returns are driven by capital expenditures, which could potentially lead to increased spending and higher rates, whereas ratepayers want to keep their electricity rates low. This conflict plays out through other channels as well. Ratepayer interests could favor greater participation of DERs and IPPs if it can help 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 could negate the potential cost-reduction value of DERs depending on the implementation. 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 IDSO is perceived as more fair than the status quo utility because it has no incentive to increase its profitability beyond what is needed 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, either an ISO or IDSO 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.

Minimize the transition process and costs

The additional criterion proposed by the Project Team is the transition cost. The "maximize consumer cost savings" criterion 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.[164] The more stakeholders involved in the transition process and the more approvals required indicates a greater probability of delays. Likewise, it is essential to consider if a new regulatory model will require divestment of assets by the utility. This can increase the opposition of the utility and the likelihood of an expensive litigation process as well as lengthening the timeframe required to sell assets.

[164] Task 2.3.1 discussed this in detail.

Increased utility oversight through a HERA entity would be the least burdensome alternative regulatory model with respect to transition costs and timeframe. 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.[165] 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 "light" to "comprehensive" mechanisms—and involves price- vs. revenue-cap approaches (as discussed in Section 5.1.4.). 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 guide 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.

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.

Furthermore, 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

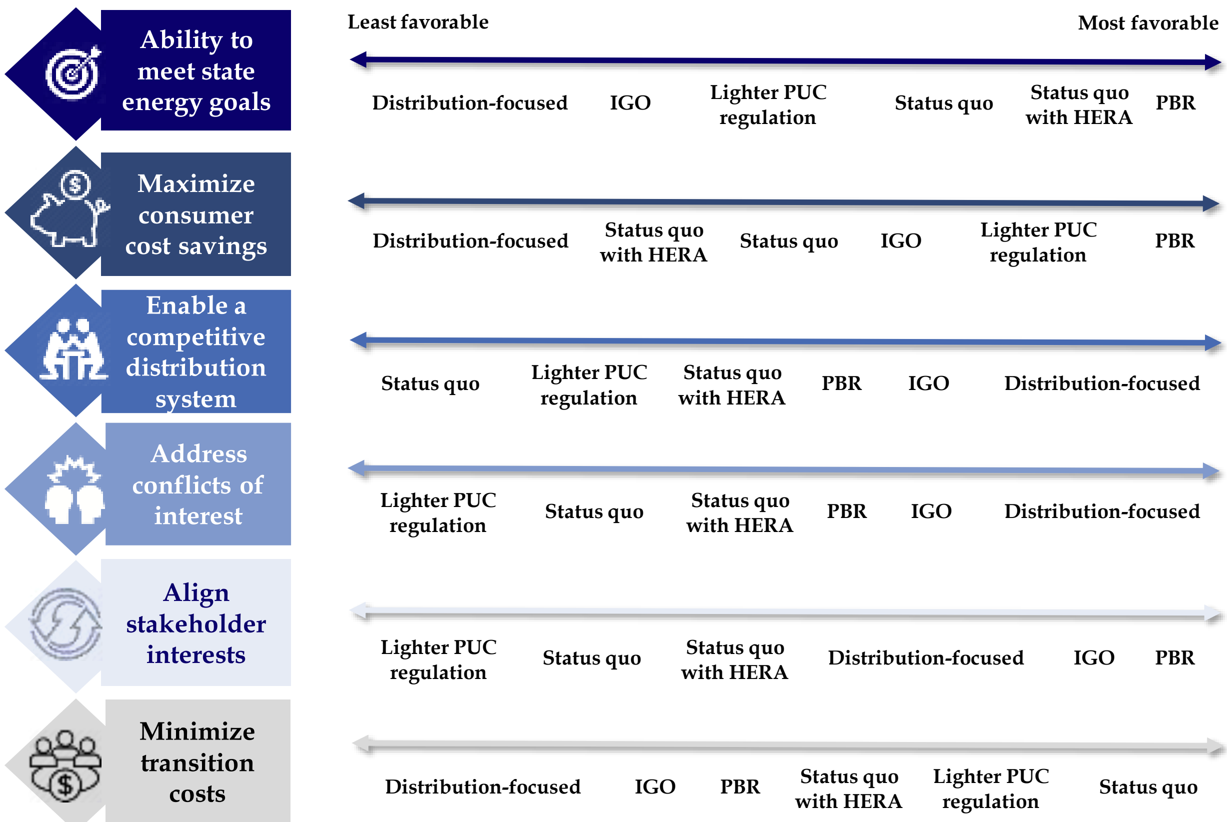
[165] HRS 269-147.

stakeholder engagement process. However, while there are several examples of well-functioning ISO markets, the same cannot be said of an IDSO or DSPP market.

Summary evaluation of regulatory models relative to the criteria

The high-level results of the Project Team's qualitative evaluation of the six regulatory models described previously with respect to each of the six ranking criteria are summarized in Figure 38.

Figure 38. Evaluation of regulatory models relative to the ranking criteria



Among the regulatory models considered for this Study, the PBR model ranked the highest while the Status Quo ranked the lowest. 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. In contrast, the Status Quo performed less favorably due to a misalignment of incentives – IOUs have incentives to favor capex spending over other types of solutions and but not to pursue efficiency improvements.

The combination of incentives and penalties enables PBR to perform most favorably in terms of meeting State energy goals, lowering costs to consumers, and aligning stakeholder interests. It could also include mechanisms like the price- or revenue-cap to control costs.

PBR also represents an improvement with respect to the Status Quo in terms of enabling a competitive distribution system or addressing conflicts of interest. For both criteria, other models create a new structure that helps to achieve those goals more effectively. However, appropriate mechanisms and design elements under PBR could still help advance those goals.

Figure 39. 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

5.6 Combining regulatory models

Analysis of the state criteria showed that combining some of the regulatory models would be more effective in facilitating the achievement of the state goals. More specifically, the PBR model could be designed to be effective alongside an ISO and DSPP/IDSO (collectively an Independent Grid Operator or "IGO"), or under additional HERA oversight. Combining PBR with an IGO could even be more effective than a standalone PBR in meeting the State's goals, except that this would lead to higher transition costs.

Combination of the Conventional PBR and a 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 combined model 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 rather than to the utilities' bottom line. Moreover, conventional PBR with revenue caps can encourage utilities to support the growth of DERs. The support would be driven by the totex approach to calculating revenue requirement, increased ease of interconnection for DERs and better designed PIMs.

Conflicts of interest would 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 a 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 could 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. Likewise, there is already legislation for a HERA in Hawaii; no further legislation would be required for a Light HERA entity.

Hybrid Model: Combination of an Outcomes-based PBR, DSPP, and ISO/IDSO ("IGO")

Another combination that could achieve most, if not all, of the state goals, is the combination of an Outcomes-based PBR, DSPP, and ISO/IDSO. As mentioned earlier, given the smaller size of Hawaii's transmission systems (compared to jurisdictions elsewhere), the Project Team believe that combining the functions of the ISO and independent IDSO is more effective and efficient in the Hawaii context. The Project Team refers to this combination as an IGO. The responsibility of planning and operations, including the dispatch of both the transmission and distribution system, falls to the IGO. It would also determine the investment requirements of both transmission and distribution networks. The utilities would continue to own the transmission and distribution assets, but the operations would be under the IGO.

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 solicitations will not be designed to favor any potential offeror, including the utility deliberately. 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 would likely be more effective in meeting the State's goals. It would 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 could also help lower the transition costs of this Hybrid model and make it 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.

Task 2.2.1 *(High-level evaluation of the regulatory models relative to the State's goals)* discusses this in detail.

5.7 Potential stranded costs

In the case of regulatory models where assets remain regulated (such as the Status Quo and PBR), there would not be stranded costs related to the change in the regulatory regime. Since the utility assets, or rate base assets, were procured under the oversight of the PUC, the acquisitions are presumed to be reasonable and necessary to the continued reliable operation of the power grid in each county.[166]

On the other hand, for the other regulatory models such as the IGO and DSPP, the utility could be encouraged to transfer or divest certain classes of assets, mostly related to generation, to an unregulated subsidiary or IPPs. 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 would purchase the assets at a price that allows it to recover its costs and earn its desired return on investment, given the expected magnitude of market revenues. 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 generation assets in the State, as illustrated in Figure 40.

[166] There may be stranded costs at the time the assets are retired if not fully depreciated, but these costs would not be caused by the change in regulatory regime but rather by the evolution of the generation resource mix.

These stranded costs calculation is indicative, as the magnitude of actual stranded costs may differ due to a variety of factors such as:

1. market risk vs. regulatory certainty for acquiring entity;
2. the 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.

Figure 40. Potential stranded costs for utility generation assets in the State of Hawaii

Utility	Potential Stranded costs
HECO	$321.9 million
HELCO	$12.5 million
MECO	$11.3 million
KIUC	$31.9 million

In addition, all options considered 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 the regulatory regime.

Task 2.2.4 *(Summary analysis and conclusions related to estimating stranded costs for each regulatory model)* provides a more detailed discussion on potential stranded costs from a change in regulatory model.

5.8 Feasibility of the regulatory models

Similar to the process in the ownership models, the Project Team conducted a high-level technical, financial, and legal feasibility of each regulatory model. Based on the technical feasibility analysis, all models should be able to comply with service, quality, and reliability standards, with an independent monitor or the Commission itself enforcing standards. Moreover, three of the assessed models—the HERA, IGO, and distribution models — require the creation of new entities. The PUC would play a pivotal role in defining the mandate and scope of these new entities.

Furthermore, the regulatory models differ in their ability to facilitate the achievement of the State's energy goals. The PBR model could be designed to incentivize achievement of the State's goals directly through the PIMs, while incorporating all of the State's broader policy goals within an IGO construct may limit potential efficiency gains. The HERA model is limited by its legislatively mandated scope (on reliability) while the DSPP model is promising but carries a high level of implementation risks.

When it comes to financial feasibility analysis (for most models), the financial requirements for the implementation of each model vary significantly by model. The IGO and DSPP models likely require the most significant investments to create and fund the new IGO entity. IGO costs could be higher if independently implemented on each island. The costs associated with the implementation of PBR will be the result of an intensive regulatory process before the PUC to create new mechanisms. HERA funding will be secured via a legislative mandate, but the magnitude of costs would still vary depending on the ultimate scope of HERA's mandate. The financial impact of each model on ratepayers, therefore, varies for each model, with implementation costs driving impact to customers.

Meanwhile, the legal framework for the successful implementation of the models represents a barrier, especially for the IGO model, which will likely require new legislation before its implementation by the PUC. The PBR and HERA models do not require enabling legislation since both are already authorized by Hawaii State law but would still require a PUC investigative docket or rulemaking proceeding before implementation. As of this writing, the PBR docket is underway. The DSPP model would not require new legislation, but it may still be helpful for practical reasons to have legislation that would provide the PUC with the authority to define a new utility business model and new roles for stakeholders. Moreover, there are several legal issues that should be addressed during the implementation of the models. These include determining the status of existing PPAs, fuel purchasing contracts, and reassuring the financial viability of prior investments (e.g., the need to ensure a reasonable return for prudently made investments by utilities during previous regulatory regimes).

Task 2.2.3 *(High-level assessment of the technical, financial, and legal feasibility of each regulatory model)* discussed in detail the results of the high-level feasibility review.

5.9 Views of the stakeholders

Location of the community outreach

- City and County of Honolulu
  - Honolulu
  - Kailua
- Hawaii County
  - Hilo
  - Kona
- Maui County
  - Lanai City, Lanai
  - Wailuku, Maui
  - Kaunakakai, Molokai
- Kauai County
  - Lihue

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 the textbox on the left. Additionally, the Project Team conducted a workshop at the VERGE conference in Honolulu on June 12th, 2018.

The objectives of the workshops were to provide stakeholders with information regarding the various regulatory models under consideration as well as to receive their input on the priorities for the regulation of the electric sector, and their 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.[167]

In addition to the workshops, multiple bilateral meetings were held 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 PBR implementation, to interest in only minor revisions to the Status Quo, to concern for unintended consequences due to the difficulties in designing PBR well, to support for Lighter PUC Regulation of co-ops. The main takeaways of the outreach effort are summarized in Figure 41.

Figure 41. Summary of pros and cons of each regulatory model according to the participants of the community outreaches

Models	Pros	Cons
1 **Status quo**	**Reliable** electricity	does not encourage the utilities to invest sufficiently in improving **grid resiliency** not successful in lowering **electric rates** utility is not incentivized to take action or make investments in line with **community priorities** does not allow **sufficient access** to the grid for IPPs
2 **HERA**	might **increase grid access and increase deployment of renewables**	would be **redundant**, since the PUC already assumes much of the role might **increase costs**
3 **IGO**	would increase **competition**	would be **too costly to implement** the **market is too small in Hawaii** for an ISO to work
4 **DSPP**	would increase **competition** and deployment of **DERs**	would not work in Hawaii as the **cost would be too high**
5 **PBR**	Would be able to **link utility revenues to its performance** Incentives could align utility investments with policy goals	would be **difficult to design and implement** PBR well It might be too **risky**
6 **Lighter PUC regulation**	PUC regulations are **unnecessary** Hawaii should follow the **example on mainland** where co-op are not regulated as heavily as IOUs a reduction in regulations would **reduce costs** for both KIUC and the PUC	could result in the state's **inability to ensure co-ops comply with state policy goals**

[167] The majority of participants at VERGE did not sign in.

All participants to the community outreach agreed that the current regulatory model results in the provision of reliable electricity to the state. There was a general concern in relation to the HECO Company utilities, however, that the status quo does not encourage the utilities to invest sufficiently in improving grid resiliency. Across the state, participants believed that this model has not been successful in minimizing electric rates. 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 would ultimately increase overall costs.

Though it was recognized that an IGO would increase competition, stakeholders felt that it would be too costly and that the market is too small in Hawaii for an IGO to work.

Participants' opinions varied greatly regarding a DSPP model. While many argued 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.

Participants 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. Nevertheless, many stakeholders highlighted that it would be difficult to develop 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.

There was broad support for Lighter PUC Regulation of co-ops, mainly from stakeholders on Kauai. Many stakeholders said that the 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 felt that a reduction in regulations would reduce costs for both KIUC and the PUC.

Task 2.2.5 *(Outreach Plan and documentation of results of public outreach)* documents the views of the participants to the community outreaches for the regulatory models.

5.10 Regulatory models selected for further review for the HECO Companies

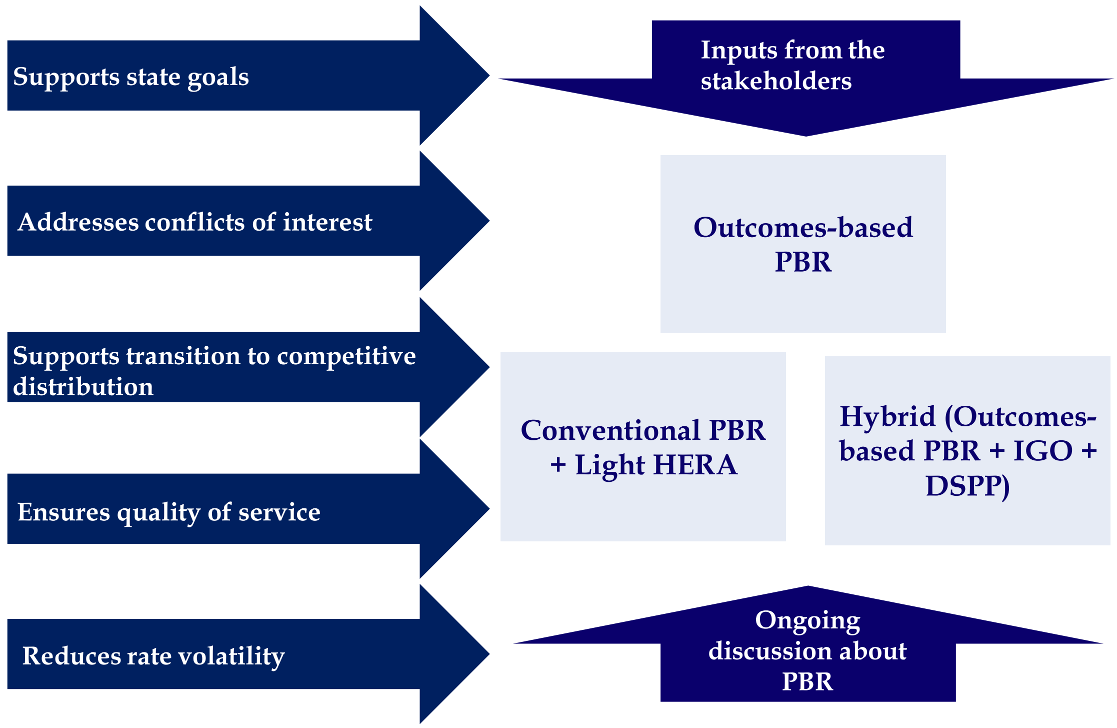
The analysis identified the most beneficial regulatory models for counties currently operating under an IOU for further study relative to the Status Quo in the succeeding tasks. These models are:

1. Outcomes-based PBR model;

2. Conventional PBR with Light HERA model; and
3. Hybrid model.

The regulatory models were assessed based on the State's key criteria. The evaluation also considered input from industry stakeholders and community members received during the outreach held in June 2018, and the fundamental expectations of the utility.

Figure 42. Factors considered in choosing the regulatory models for further study (for Hawaii, Honolulu, and Maui counties)



The Hybrid model scored similarly to 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 the interconnection of generation 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 Section 5.5) could ensure lower upfront costs and ease the transition. Once implemented, the DSPP and IGO components would also reduce the administrative burden of a PBR regime (i.e., by taking on some of the responsibilities enshrined in PIMs).

In summary, the Hybrid model scored highly for all the specified criteria and also would meet the PUC's goals of achieving:[168]

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 showed that the Outcomes-based PBR model is well-suited to the State 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 the State of Hawaii's stakeholders as the Light PBR. Consequently, the design and implementation of an Outcomes-based PBR would involve more data collection, analyses, and monitoring requirements, likely leading to higher implementation costs.

The combination of the Conventional PBR with Light HERA also ranked favorably in the 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 scored well across the board in the other major and minor categories. Task 2.2.6 (Identification and recommendation for the three most beneficial regulatory models for further consideration) provides a more detailed discussion on the scoring for this model.

5.11 Regulatory models selected for further review for Kauai County

A separate analysis conducted for Kauai County suggests the three most beneficial regulatory models for Kauai County are:

1) HERA model;
2) IGO; and
3) Lighter PUC Regulation.

The HERA model ranked favorably given the regulatory model's potential to support the State policies, strengthen the utility's performance, and its 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 imply significant transition costs. It would also increase the likelihood of rate volatility due to the market structures and would require

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

substantial legal work. However, it is more likely to result in greater competition at the distribution level.

The Lighter PUC Regulation model implies reducing the PUC's current regulatory oversight over KIUC to reduce the co-op's regulatory burden and improve its ability to launch new initiatives. 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 hamper the ability to achieve the State goals because the PUC or other state bodies would have less control in directing the utility towards particular targets or programs. Furthermore, the implementation of this model also has potential drawbacks because less PUC oversight comes with fewer 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.

Task 2.2.6 *(Identification and recommendation for the three most beneficial regulatory models for further consideration)* provides a more detailed discussion on the methodology and approach to determining these three most beneficial regulatory models.

5.12 Indicative timeline to transition to another regulatory model

The steps in the implementation of a PBR regulatory model, regardless of whether it is Outcomes-based or Conventional, include decision-making on the design of the PBR model, issuance of guiding principles and framework for the model, determining outputs and price control methodology, engaging with stakeholders, working with utility companies to develop business plans that are compliant with the new model and revising non-compliant utility company business plans, and finally setting the price control mechanism.

Based on the Hawaii Ratepayers Protection Act (SB2939), PBR needs to be implemented in the state by January 1, 2020. It should take 21 months from the date the law went into effect for the PUC, HECO Companies, and other involved parties to implement the PBR model. Notably, the process has begun with an active investigatory docket already in progress. Hawaii's statutory timeframe is shorter than the time used in the implementation of a similar model in the UK, where the process took 30 months to complete. Nevertheless, the Project Team anticipates that the State could implement PBR in a shorter timeframe as it is a smaller jurisdiction with less complex regulatory structures. The selection of fewer and less complicated regulatory mechanisms could also reduce timelines.

Likewise, the steps in the implementation of Light HERA (under the Conventional PBR + Light HERA model) are the same as those involved in any PUC investigative docket because there is already legislation authorizing HERA. The PUC has stated that the next step in implementing HERA is an investigative proceeding, which follows a fairly typical docket proceeding format and schedule that should take approximately two years to complete, based on the average duration of other PUC docket proceedings. Two years is also a reasonable assumption because the HERA implementation is not tied to a strict deadline, unlike the PBR implementation.

When considering the steps and timeline for the implementation of a combined Conventional PBR + Light HERA model, the total timeline would depend on whether the processes are staggered or not. In the Study, these two models were assumed not to be implemented at the same time. Thus, it is anticipated that establishing this model would take between 39 and 42 months.

Among the three regulatory models selected for further study, the Hybrid model would take the longest to implement. The Hybrid model could be applied in phases/stages over a longer timeline to reduce rate risk that would be inherent with too many regulatory changes at once. The Project Team's staggered implementation features a January 1, 2020 implementation of Outcomes-based PBR to comply with state law, implementation of the IGO in 2023, and implementation of DSPP operations beginning in 2028.

The IGO is likely to take approximately two years to implement, which is similar to the timeline for implementation of ISOs in New York, Texas, and California. Other specific steps regarding the IGO implementation will depend on the design and implementation method the State wishes to use. It is expected that additional steps could be required by an investigatory proceeding into the creation of an IGO to ensure open access, functionally unbundle transmission service, and establish open access transmission tariffs. The results of these steps would also inform action by the state legislature.

The DSPP's implementation is likely to take at least three years and be conducted through a regulatory proceeding. This estimate is based on the experience of New York State, which has been in the process of planning and implementing DSPP since late 2013 and is still not complete at the writing of this Final Report. New York State has initiated a large proceeding over the course of these 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 various aspects of the overall REV model, including the transition of utilities to Distributed System Platforms. Specific steps they have undertaken include the creation of a Distributed System Implementation Plan Guidance document, approval of joint and individual Distributed System Implementation Plans and the design and implementation of Demonstration Projects by utilities in select service areas. Hawaii is significantly smaller than New York State, and its IOU utilities are organized under the same parent company, so it is possible that implementation could be quicker, especially if Hawaii State regulators can draw on the experience of the New York State initiative.

Task 2.3.1 *(Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models)* discusses this in detail.

5.13 Legal changes needed to transition to another regulatory model

No changes to the state law would be required to establish a PBR model or implement a Light HERA. It follows that no legal changes would be needed for the Outcomes-based PBR model or the Conventional PBR with Light HERA model. The existing legal framework grants the PUC broad authority for ratemaking and to regulate the electric utilities, which would likely include authority to change the ratemaking procedure from COS to PBR. Furthermore, the Hawaii State Legislature enacted in 2018 a law specifically requiring the design and implementation of PBR in the State.

On the other hand, the Hybrid model would require new legislation to enable the various components of this model, for instance, the IGO. While the state has no explicit law for a DSPP model, its creation should fall under the broad regulatory authority of the PUC. However, to err on the side of caution, and to follow its own precedent of legislating specific PUC responsibilities, the state legislature may want to issue legislation to authorize DSPP explicitly if this model is to be adopted. For the IGO model, there is currently no legal authority to create an IGO. 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), the Project Team expects that legislation explicitly authorizing the creation of an IGO, and its regulation by the PUC, would be necessary to implement this element of the Hybrid model.

Task 2.3.2 *(Analysis of Hawaii law and history to determine the regulatory and legislative changes needed to implement the recommended regulatory models)* provides a more detailed discussion on this.

5.14 Potential costs required to implement the regulatory models

The costs of implementing PBR include the operational costs associated with the PUC and stakeholders undertaking the work necessary to implement the model successfully. Based on an analysis of jurisdictions that transitioned from COS to PBR, such as Alberta (Canada) and UK, together with a review of the PUC's current operating expenses, the Project Team estimated that the cost of implementing Conventional PBR in the State could result in a 10.9% increase in the PUC's average annual expense during the transition period. The costs of operation following the transition period would be similar to the PUC's current average annual 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 a system with a HERA-like entity. In particular, the Project Team looked at the Electric Reliability Council of Texas ("ERCOT") Reliability Authority, as the states of Texas and Hawaii are similar in that they both are isolated from the interconnected power systems serving the eastern and western United States,[169] and have integrated significant quantities of renewable generation over the past few years. Using this analysis, The Project Team estimated that the HERA transition costs could range from $234,000 to $585,000 while the annual operating costs would range from $483,000 to $1,208,000.[170]

For the Hybrid model, the Project Team acknowledged uncertainty for cost calculations in both the IGO and DSPP models because there are few examples from which comparisons may be drawn. Nevertheless, depending on the method of calculation, the IGO would cost at least $8 million to $67 million in startup costs, with annual operating costs of a similar magnitude, based on a scaled comparison to mainland RTOs, which are similar to the proposed IGO.[171] The costs of

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169 Although Texas does have asynchronous interchange capability with the rest of the mainland US grid.

170 The direct scaling cost estimates for a transition to HERA ($234,000 to transition, $483,000 annual operating costs) refer to the scaled, per-kWh start-up costs of ERCOT's Reliability Authority and the operating costs of NERC. The more conservatively scaled estimate that reflects Hawaii's smaller size ($585,000 to transition, $1.2M in annual operating costs) is derived by applying FERC's 250% cost factor for small jurisdictions.

171 The lower estimate of $8 million for startup and annual operation costs is based on the "small jurisdiction" per-MWh cost identified by FERC and the forecast of 11.9TWh in annual electricity sales in Hawaii. The larger

implementing a DSPP are estimated at approximately $51 million for all the three IOU utilities, spread over a three-year transition period, and $1 million in annual operating cost thereafter.[172] The cost estimates are derived by scaling the costs of National Grid's Distributed System Platform demonstration project in Buffalo, NY (which is part of the NY REV proceeding) to Hawaii by the amount of distributed generation resources served. While the DSPP component of the Hybrid model adds substantial costs, it could also expand the potential to open new revenue streams and encourage the use of more DERs. Task 2.3.1 *(Identification of steps, costs, and projected timelines, for change from the current regulatory model to the recommended regulatory models)* discusses this in detail.

5.15 Funding mechanisms

Under the Outcomes-based PBR model, how 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 capex, such as the Major Project Interim Recovery 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 PIMs and a likely increase in savings due to fewer 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).*

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, utilities would be able to create a surcharge to be collected to fund the entity elected to be HERA.

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

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estimate of $67 million in startup and operational costs is based on the lower range of the cost range provided by FERC.

[172] The cost estimates for IGO and DSPP refer to the combined costs across the HECO Companies. In the analyses, the Project Team allocated a share of these costs to each utility based on overall demand for IGO, and on planned DER capacity for DSPP. The Project Team acknowledged that this approach may underestimate the fixed costs necessary to implement these models on each island.

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 ISOs. Like ISOs such as ISO New England, New York ISO, and PJM Interconnection, the IGO could fund its opex and capex through a combination of private financing and fees to market participants (which would trickle down to retail customer bills).

Task 2.5.5 *(Identification of funding mechanisms for each regulatory model)* provides a detailed discussion on the potential funding mechanisms for these regulatory models.

Figure 43. 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

5.16 Potential impact on the staffing needs of the PUC

Since the three most beneficial regulatory models are relatively innovative, only a few jurisdictions have some elements of these recommended models in their current regulatory framework. Therefore, the Project Team selected some jurisdictions for further review of staffing in relevant agencies. 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.[173] Since no jurisdiction currently has the Hybrid model, the Project Team chose New York as an example because its REV initiative shares similar elements to the Outcomes-based PBR as well as DSPP models. New York also has an independent system operator. The Project Team compared the staffing numbers before and after the change of regulatory models to study the impact of the change on staffing relevant State agencies.

[173] 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.

The Project Team's 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;

- 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 (e.g., New York State) with the Hybrid model;
- When implementing PBR mechanisms, the PUCs usually hire external consultants, which might result in 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, it is anticipated that a potential 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). On the other hand, implementation of the Conventional PBR with Light HERA model as well as the Hybrid model could potentially increase PUC's staffing needs, given their additional responsibilities.

Furthermore, the oversight management and staffing needs of related State agencies and stakeholders will be affected by various factors other than the regulatory model. This analysis is a relative assessment for the purposes of comparing alternative utility regulatory models. The Project Team's review 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.

Task 2.3.4 *(Assessment of how each regulatory model could impact state agencies)* provides an analysis of how a change to the regulatory model could affect the staffing needs of the PUC.

5.17 Potential impact of the regulatory change on DERs

A change to the State's regulatory models could be considered as one of the key drivers of DER deployment with respect to facilitating interconnection, incentivizing utility investment, and creating markets for DERs to offer grid services.

Among the regulatory models reviewed, the Hybrid model and the Outcomes-based PBR would most likely provide the most positive impacts on DERs.

As discussed earlier, the Hybrid model combines the Outcomes-based PBR, DSPP, and IGO models, taking advantage of the benefits that each of those regulatory models offers to support DER penetration. An Outcomes-based PBR would allow regulators to incentivize utilities to include DER interconnection targets in their multi-year business plans. A DSPP creates a marketplace and revenue streams for DER products, thus attracting investors. Meanwhile, through an IGO, third-party DER providers would benefit from a transparent interconnection process, thereby addressing inherent conflicts of interest that the utility faces under other regulatory regimes. Figure 44 illustrates the overall impact that a shift in the regulatory model could have on the level of DERs as well as energy security and reliability in the State of Hawaii.

Figure 44. Impact of change of regulatory model to the DERs and energy security and reliability

Change of the Regulatory Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Move to Outcomes-based PBR	↑	↑	↑	↑	↑	↑
Move to Conventional PBR with Light HERA	↑	↑	↑	↑	—	↑
Move to Hybrid model	↑	↑	↑	↑	↑	↑
Move to Lighter PUC Regulation	—	—	—	—	—	—

Finally, the successful integration of high levels of DERs would depend on the design of the mechanisms and incentives provided to both the utilities and DER providers, as well as on the political will of the government to complete the transition. Task 2.4.1 *(Estimated potential for each model to increase distributed energy resources)* provides a more detailed discussion on this topic.

5.18 Potential impact of the regulatory change to the residential electricity rates in Honolulu, Hawaii, and Maui Counties

For Honolulu, Hawaii, and Maui Counties, the implementation of the three models each result in the lowest projected average residential rates, as shown in Figure 45 below.

- Conventional PBR + Light HERA model in Honolulu County;
- Hybrid model in Hawaii County; and
- Outcomes-based PBR in Maui County.

The implementation of the three regulatory models is projected to lower average electricity rates relative to the Status Quo in these counties during the forecasted horizon. The most important drivers of cost efficiency and lower rates are:

i) PIMs that incentivize the utility to lower certain categories of costs. The PBR models included several types of PIMs that offer financial incentives in the form of shared savings to the utility for lowering certain categories of costs. These categories include the cost of the final delivered energy, the total cost per customer, the total cost per km of wires, and cost savings in renewable generation procurement.

ii) ESM, which allows the ratepayers to recover half of the utility's excess earnings. Even after cost savings under PIMs, if a utility's actual revenues for a year result in an effective rate of return that is higher than the approved rate of return plus a pre-determined dead band, an ESM allows ratepayers to recover half of the excess earnings in the next regulatory period.

iii) The totex approach, which incentivizes the utility to lower overall spending on capex and opex combined. Under the totex approach, utilities set an overall expenditures target, combining both capital and operating expenses. Utilities would also retain part of the savings if they lower their spending below the target levels. In addition, relative to the Status Quo, the forecasted returns on RAB are projected to be higher under the PBR models despite lower totex spending.[174]

It is important to note that although the rates are projected to be lower in real terms under the PBR models compared to the Status Quo on average between 2018 and 2045, there are some years for which rates are higher for the PBR models. Task 2.5.2 *(Assessment of system average retail rates for each regulatory model)* provides an evaluation of the projected retail rates for residential, commercial, and industrial customers up to 2045.[175]

The impact of each regulatory model varies between the utilities because of the relative importance of rate base, purchased power expenses, PIMs, and ESMs for each utility's revenue requirement calculations.

Compared to the analysis of ownership models, separate assessment for different regulatory models being implemented on an island-by-island basis for Maui County was not performed. In other words, it assumed that any regulatory model implemented on Maui County would be the same across the three Maui County islands. Implementing a different regulatory model on each island would increase costs of the utilities, PUC, and DCA. Therefore, it is more advantageous in terms of costs and efficiency to minimize the regulatory differences to the extent possible across the islands.

[174] Regulated Asset Base under the cost-of-service model is the net book value of the utility's investment base on which a rate of return is applied to determine the allowed return to investors. Under the totex approach, a pre-determined proportion of the total expenditures gets added to the RAB, based on a capitalization rate. This would remove the capex bias that IOUs have under the cost of service model.

[175] To derive the projected average retail rates under each ownership model up to 2045, the Project Team created a revenue requirements model for each regulatory model and for each county. For the ownership models, a total of 12 revenue requirements models was created. Please refer to the following memos for additional information on the assumptions that the Project Team has used and the results of the revenue requirements: Task 2.5.1 *(Estimated annual revenue requirements for each of the remaining recommended regulatory models)* and Task 2.5.3. *(Analysis of how costs differ under each regulatory model).*

Figure 45. Average impact of a change in the regulatory model on residential rates relative to the Status Quo (2018 – 2045) for customers of the HECO Companies

Change of the Regulatory Model	Honolulu County	Hawaii County	Maui County
Implement an Outcomes-based PBR model	-2.1%	-4.8%	-2.2%
Implement a Conventional PBR + Light HERA model	-2.2%	-4.4%	-1.9%
Implement Hybrid Model	-0.4%	-9.2%	-2.2%

5.19 Potential impact of the regulatory change to the residential electricity rates in Kauai Counties

For Kauai County, Lighter PUC regulation results in the lowest rates because of lower anticipated regulatory costs for the utility. On the other hand, the HERA model would yield the highest rates because HERA represents an incremental expense without direct financial benefits to the ratepayers. The benefits of HERA are more oriented towards the quality of service than cost reductions. As for the IGO model, the Project Team anticipates that there would be some efficiencies from transferring grid operations to a specialized independent entity that manages both utility-scale and distribution level supply resources.

Figure 46. Average impact of a change in the regulatory model on residential rates relative to the Status Quo (2018 – 2045) for KIUC customers

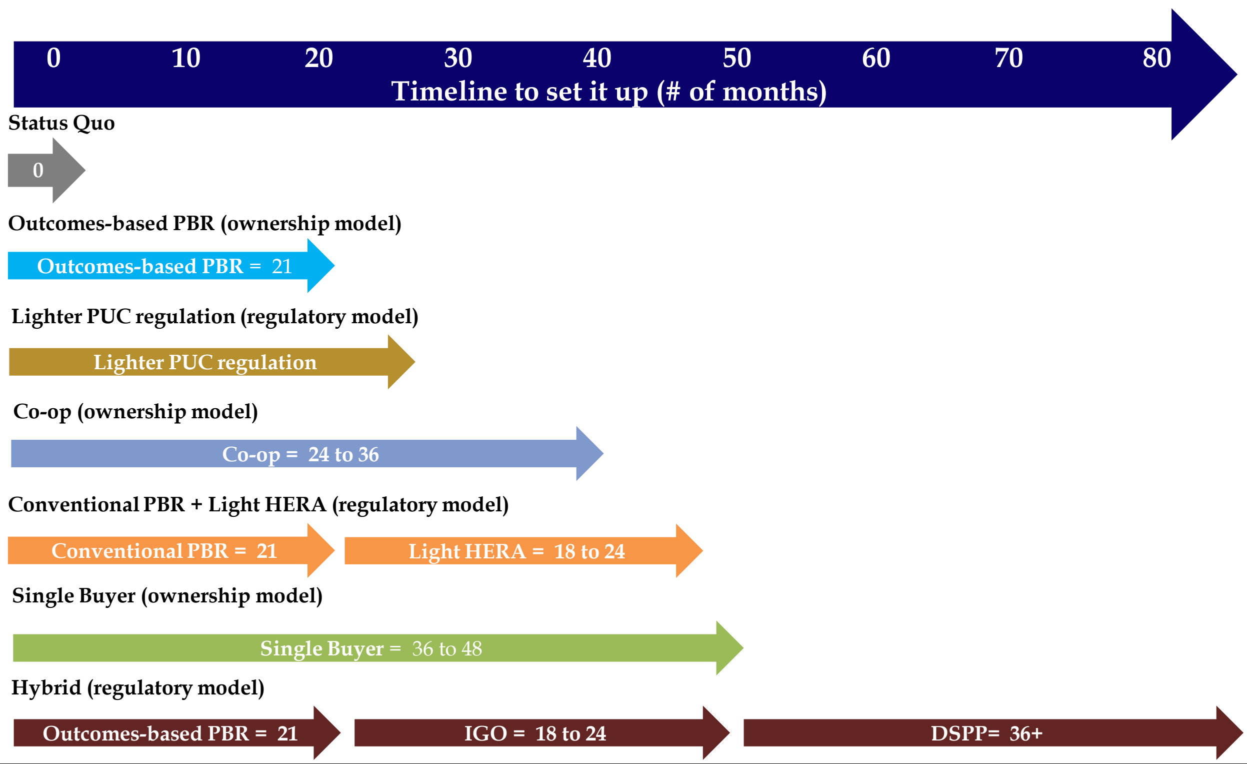
Change of the Regulatory Model	Kauai County
Move to a Lighter PUC Regulation	-0.8%
Establish a HERA model	0.0%
Establish an IGO model	-0.2%

6 Combining the findings under the ownership and regulatory models

6.1 Timeline to move to another model

Among all the selected models reviewed, the Outcomes-based PBR model would take the shortest time to implement because there is already an existing law allowing for the implementation of this model and an open PUC docket. On the other hand, the Hybrid model would take the longest since this model involves the creation of the IGO and DSPP, which currently would require some legislation changes.

Figure 47. Indicative timeline to set up the different regulatory models



6.2 Legal changes needed to move to another model

The only ownership or regulatory models the implementation of which would require a change in the law are the SB, Hybrid, and, potentially, the Lighter PUC regulation models. Current legislation already allows for the creation of HERA and the implementation of PBR. Legislative action is needed to create the new entities associated with the SB, IGO, and DSPP constructs.

For lighter regulation of co-op utilities, 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 regulatory requirements (i.e., for KIUC to be deregulated).[176] However, there is currently no authority for the PUC to otherwise revise or customize regulatory requirements for electric co-

[176] HRS § 269-31(b); HAR §§ 6-61-159, 160.

ops that are unique from the regulation of IOUs. As such, assuming an intent to customize regulatory requirements that apply 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.

Figure 48. Summary of legal changes required for each model

	Models	Legal/regulatory changes required to move to a new model
Ownership Models	**Status Quo (IOU)***	No
	Co-op	No – burden of proof rests on the co-op to demonstrate that it can meet the laws and regulations already in place
	Single Buyer (within the utility)	Yes – Might require a PUC proceeding
	Single Buyer (outside the utility)	Yes – Legislative action is required to establish a new entity to undertake planning and procurement responsibilities from the utility
Regulatory Models	**Status Quo (COS with some PBR mechanisms)**	No
	Outcomes-based PBR	No - no legal changes needed because PBR falls under existing PUC authority
	Conventional PBR + Light HERA	No - there is existing regulation already for both PBR and HERA
	Hybrid	Yes - PUC proceeding is required and legislative changes may be required to authorize a DSPP
	Lighter PUC regulation	Yes - the State Legislature would need to either customize any statutory laws for electric co-ops or authorize the PUC to do so

6.3 Various costs required to move to another model

A change in ownership or regulatory model would be accompanied by certain costs of transition as well as changes in the costs of utility operations. Broadly, a change in model results in three categories of impact on costs.

Transition costs

Any changes in the model would entail costs associated with conducting the necessary stakeholder outreach, or creating new entities like SB and IGO, or passing new laws and regulations. These costs can vary based on the timeline of the transition and extent of legal or regulatory changes required. Changes in the law could be necessary to create an SB outside the utility or an IGO, which would mean higher costs of transition.

Non-recurring implementation costs

The initial costs to implement a new model can be of different types. For a change in ownership from an IOU to a co-op, an acquisition transaction is necessary for the newly formed co-op to purchase the assets and operations from the incumbent utility. In case of a change to an SB model or creating an IGO and DSPP for the Hybrid regulatory model, implementation requires initial capital expenditures on the software and office facilities of the new entity.

Recurring costs of operation

Once the utility operations commence under a new model, some categories of costs change from the Status Quo. Under a co-op model, a utility would be exempt from federal income taxes, would have lower interest rates but higher interest expenses from the initial acquisition, and is expected to have lower costs of procuring power. An SB is also expected to have lower purchased power costs, but the utility's expenses under its planning and procurement divisions would be lower since some of those functions would move to the SB. Similar changes are also expected with an IGO. Under a PBR regime, utilities face incentives to achieve certain outcomes in the form of rewards or penalties.

The Project Team expects that all costs are ultimately passed to ratepayers, either directly or indirectly. Ratepayers are expected to benefit financially from a change in the model if there are sufficient costs savings under the third category – recurring costs of operations – to make up from the transition and implementation costs. A change in ownership from the incumbent IOU to a co-op would have the highest implementation costs due to the acquisition costs. The Hybrid regulatory model would also entail high implementation costs to establish an IGO and DSPP alongside an Outcomes-based PBR model, but the Team envisions that there would be staggered implementation, which would help lower cost impacts to ratepayers.

6.4 Potential impact on the PUC staffing

A change in the ownership or regulatory model does not necessarily require a change in the staffing needs of the PUC. There are other factors that may impact the PUC's staffing needs, such as complexity of policies or initiatives of the jurisdiction, number of utilities, number of customers, and services provided by the PUC.

6.5 Potential impact on DERs

Among the most beneficial models reviewed, the regulatory models would most likely provide the most positive impacts on DERs (Figure 49). The Hybrid and the Outcomes-based PBR models would most likely help in the growth of all types of DERs such as DGs, storage, DR, EE, and EV. This is because these models would likely incentivize utilities to include DER interconnection targets in their multi-year business plan. Under the Hybrid model, the DSPP would create a marketplace for DER products and thus attract investors. Third-party DER providers would also benefit from fair interconnection process through the IGO.

Moreover, the models that have a PBR variation would most likely strengthen energy security and reliability because of the incentives that could be tied to the utility's performance in ensuring these.

Lastly, among the models, the Lighter PUC Regulation would most likely not significantly impact the deployment of DERs.

Figure 49. Indicative impact on the DERs

	Change of the Regulatory Model	Distributed generation	Energy storage	Demand response	Energy efficiency	Electric vehicles	Energy security and reliability
Ownership	Move to IOU	—	—	↑	—	↑	—
Ownership	Move to co-op	↑	↑	↓	↑	—	—
Ownership	Move to Single Buyer (within the utility)	↑	↑	—	—	—	—
Ownership	Move to Single Buyer (outside the utility)	↑	↑	—	—	—	—
Regulatory	Move to Outcomes-based PBR	↑	↑	↑	↑	↑	↑
Regulatory	Move to Conventional PBR with Light HERA	↑	↑	↑	↑	—	↑
Regulatory	Move to Hybrid model	↑	↑	↑	↑	↑	↑
Regulatory	Move to Lighter PUC Regulation	—	—	—	—	—	—

6.6 Potential impact on residential rates

The combined results of the revenue requirement and rate analyses for both ownership and regulatory models, illustrated in Figure 50, indicate that changing the regulatory model is more effective at lowering rates than changing the ownership model. Indeed, for the three counties with an incumbent IOU, all three recommended regulatory models are expected to lower rates, on average, between 2018 and 2045, with respect to the Status Quo and other ownership models. For Kauai County, the Lighter PUC Regulation model is projected to yield the lowest rates. While the HERA model is not expected to impact rates with respect to the status quo, the IGO model is expected to result in lower rates than the IOU or SB models.

In general, the ownership changes are projected to be less efficient than regulatory changes at lowering rates primarily because changes in regulation can impact a wider range of cost factors and therefore offer greater flexibility in lowering rates. For instance, in counties with a Status Quo IOU, the PBR models offer multiple levers with which to lower rates. PIMs could be designed to target specific categories of costs, which would offer stronger and more direct incentives for the utilities to lower them. With the totex approach, utilities could offer fair returns to their investors even while improving their efficiency with regards to overall expenditures. Finally, the ESM component would effectively act as a delayed cap on utility earnings – excess earnings in one regulatory period would be returned to the ratepayers in the next.

Figure 50. Summary of impact on residential rates by county and model (average, 2018 – 2045)

	Honolulu County	Hawaii County	Maui County	Kauai County
Alternative ownership model				
Move to a co-op model	5.3%	8.2%	-1.8%	
Move to a Single Buyer within the utility model	-0.7%	0.3%	-1.3%	1.0%
Move to a Single Buyer outside the utility model	-0.8%	0.3%	-1.3%	1.0%
Move to an IOU model				6.7%
Alternative regulatory model				
Implement an Outcomes-based PBR model	-2.1%	-4.8%	-2.2%	
Implement a Conventional PBR + Light HERA model	-2.2%	-4.4%	-1.9%	
Implement Hybrid Model	-0.4%	-9.2%	-2.2%	
Move to a Lighter PUC Regulation				-0.8%
Establish a HERA model				0.0%
Establish an IGO model				-0.2%

In Kauai County, it is assumed that KIUC is already operating with a cost minimization approach, so a change in the ownership model is not expected to result in additional cost reductions. Therefore, the costs associated with the transition to a new ownership model would increase rates. A change in the regulatory model, on the other hand, could offer opportunities to lower specific categories of costs. A Lighter PUC Regulation model is expected to result in the lowest average rates for KIUC members because the utility's regulatory expenses would decrease. The IGO model is expected to improve cost efficiency in overall grid planning and operations, especially in integrating DERs but also add costs for the transition and subsequent operation of the IGO. Although the IGO model is also projected to lower average rates relative to the Status Quo co-op, the net benefits in terms of rate reduction would be lower than under a Lighter PUC Regulation model.

7 Additional analyses

7.1 Comparative assessment of rate design changes

The Project Team also conducted a high-level qualitative assessment of whether the benefits of ownership and regulatory model changes can be achieved through changes in rate design. The alternative rate design options evaluated in the analysis are summarized in Figure 51 below.

Figure 51. Rate design options

Rate	Description
Time-of-Use ("TOU") Rates	Provide time-differentiated pricing which reflects the expected cost of providing electricity. TOU rates typically differentiate between "on-peak" and "off-peak" periods to reflect variable prices with on-peak periods having higher energy charges. TOU rates provide improved price signals compared to traditional flat rates and therefore incentivize consumer response. As a result, TOU rates have the potential to maximize consumer savings and encourage the adoption of DERs.
Real-Time Pricing ("RTP") rate	Another form of time-varying rate design in which the consumer rates reflect the actual real-time hourly costs of generating and delivering electricity. RTP rates require the use of smart meters capable of monitoring and reporting hourly prices and usage patterns.
Critical Peak Pricing ("CPP") rates	Rate design in which utilities set substantially higher rates during "critical peak periods" which occur during specific hours of a given year. Similar to TOU rates, this design incentivizes consumers to lower their energy consumption during the identified peak periods and subsequently increase their savings.
Inclining block rates	One of the most common forms of residential rate design, it involves a mechanism by which energy rates increase as the amount of energy consumption increases.
Declining block rates	This rate design offers decreasing energy rates as consumers increase their level of energy consumption. It encourages increased energy consumption by consumers and consequently fails to maximize cost savings or encourage adoption of alternative energy sources such as DERs.

After recalling the benefits of the most beneficial ownership and regulatory models evaluated in prior tasks, a comparative assessment of the alternative rate design options was performed. In doing so, the Project Team assessed the relative ability of these rate design changes to:

1. maximize consumer savings (including the maximum possible impact in percentage terms based on previous experience);
2. enable a competitive distribution system in which independent agents can trade and combine evolving services to meet customer and grid needs;
3. eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation; and
4. align management, ownership, and ratepayer interests.

Based on this high-level qualitative assessment, the Project Team concluded that rate design changes can be effective complementary mechanisms to ownership and regulatory changes and could help achieve some of Hawaii's state energy goals, such as increasing the adoption of DERs and other consumer side resources, lowering peak demand, and encouraging energy conservation. Furthermore, depending on overarching ownership or regulatory model changes, rate design changes can contribute to increasing consumer savings and, to an extent, aligning utility and consumer incentives.

However, it is important to note that rate design is interlinked with prevailing regulatory and ownership models and can help advance or undermine state policy goals. As such, policymakers and regulators must be mindful of state policy objectives and the broader ownership and regulatory context when considering changes to rate design. Indeed, given the broad array of initiatives underway in Hawaii, a quantitative analysis of any potential rate design changes may be warranted once those initiatives have been implemented. Task 3.1.1. *(Assessing whether benefits of changes from ownership and regulatory model changes could be accomplished through changes in rate design)* and Task 3.1.2. *(Assessing how rate design compares to regulatory and ownership model changes considering overall market conditions)* provide a more detailed discussion of this subject.

7.2 Single-county vs. multi-county model

Aside from the analysis of ownership and regulatory models, the Project Team also conducted an assessment of the management of the State's electricity sector with each county operating independently, as compared to a multi-county model.

The single-county vs. the multi-county models were analyzed from the perspective of the utilities' management and operations, particularly with regards to how the utilities operate the electricity system from sourcing supply to dispatching resources. The Status Quo reflects a single-county model because grids in each county (island) are isolated from those in other counties. Therefore, the operation and management of electric systems are standalone and independent in each county. In contrast, the multi-county model has two or more counties that are interconnected via inter-island transmission lines, which enable joint operations and the dispatch of resources in two or more counties.

Each model has its advantages and disadvantages. The current single-county model provides easier management and operations of the electricity system in each county because the local utility leadership can make operational decisions immediately. Moreover, local utilities are likely to be more aware of what is happening in their respective counties, enabling them to act based on county-specific needs. On the other hand, a multi-county model could better utilize the available renewable resources in each county because of an interisland connection. This would then potentially lower the total cost of management and operations, thereby, reducing retail rates for electric consumers. However, the upfront costs of building and operating the interisland cables are high, making it a controversial topic that triggered significant political and social challenges in the past. Some stakeholders from neighboring counties question whether the interconnection will benefit Oahu only, especially at the costs of neighboring counties.[177]

The analysis showed that the multi-county model is better positioned to address the State's policy priorities as laid out in House Bill 1700 (Act 124) of 2016 and discussed throughout this report. As illustrated in Figure 52, the multi-county model received a better rating in three of five criteria, namely, ability to meet state energy goals, maximize consumer cost savings, and enable a competitive distribution system. In contrast, the single-county model works better in addressing

[177] HECO Companies. *PSIP Update Report.* December 23, 2016. Book 3. Page H-52.

two of the five criteria, namely, conflicts of interest and aligning stakeholder interests. The sixth criteria, transition costs, was not within the scope of the study for assessing single versus multi-county models as it would require a detailed analysis of the costs and policy implications of interconnecting two or more of the island grids which is a separate study unto itself.

Figure 52. Single- vs. multi-county model ability to best meet state policy objectives

Policy objective	Single-county model	Multi-county model
Ability to meet state energy goals	-	*better*
Maximize consumer cost savings	-	*better*
Enable a competitive distribution system	-	*better*
Address conflicts of interest in energy resource planning, delivery, and regulation	*better*	-
Align stakeholder interests	*better*	-

Lastly, while most of the highly ranked ownership and regulatory models would not be impacted by either approach, it would be easier to implement the cooperative model under the single-county approach. Meanwhile, the SB outside the utility model, Integrated Grid Operator and Light HERA (segments of the Hybrid regulatory model) would be more cost-effective under the multi-county approach. 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)* provides a more detailed discussion on the pros and cons of the single vs. multi-county models.

8 Appendix A: Summary of stakeholder meetings and calls conducted

8.1 Stakeholder engagement approach

Understanding the input from stakeholders across the state on the ownership and regulatory models for their utilities was an important component of this project. The Project Team interacted with stakeholders to receive their input through three primary mechanisms:

1. Core Group,
2. Public workshops, and
3. Bilateral meetings.

The Core Group was established in the summer of 2017 and consists of members representing the public sector, the counties, and the utilities (Figure 53). Meetings were held with the Core Group, either in person or over the phone, and the Project Team reached out to them via email multiple times throughout the project. The Project Team solicited input from the Core Group on stakeholder identification and outreach and to allow for comment on interim analyses.

Figure 53. Core Group

Public Sector	County Energy Coordinators	County Economic Development Boards	Utilities
• DBEDT	• Honolulu	• Honolulu	• HECO
• Consumer Advocate	• Hawaii	• Hawaii	• HELCO
• PUC	• Maui	• Maui	• MECO
	• Kauai	• Kauai	• KIUC

Two rounds of public workshops were held, in October 2017 and in June 2018. The purpose of these workshops was to solicit input from the public on the ownership models and regulatory models and to provide a high-level overview of mid-deliverable findings for Task 2 and Task 3. In addition to the public workshops, two workshops were conducted at VERGE, one in June 2017 and one in June 2018.

The Project Team also conducted bilateral meetings with multiple stakeholders during the course of the project, both in person and over the phone. Multiple stakeholders engaged in the electricity sector were contacted to request meetings, and the Project Team also received requests from individuals and organizations interested in speaking with them.

The following sections provide statistics on the number of stakeholders that participated in the workshops and with whom the Project Team conducted bilateral meetings.

8.2 Stakeholder workshop participation statistics

The Project Team conducted two rounds of stakeholder workshops during this project. In total, there were 216 participants at these workshops (see Figure 54).[178] The first round focused on the Ownership Model analysis and was conducted during October 2017. There were 141 participants across the eight workshops (see Figure 54 and Figure 55). Maui County had the highest number of participants at 45. The second round focused on the Regulatory Model analysis and was conducted during June 2018. There were 75 participants across the eight workshops (see Figure 54 and Figure 56). Maui County had the highest number of participants at 30.

Figure 54. Ownership and regulatory model workshop participants

County (Town, Island)	Ownership Model	Regulatory Model	Total
City and County of Honolulu	35	24	59
Honolulu, Oahu	29	17	46
Kailua, Oahu	-	7	7
Waialua, Oahu	6	-	6
Hawaii County	34	10	44
Hilo, Hawaii	14	5	19
Kona, Hawaii	20	5	25
Kauai County (Lihue)	27	11	38
Maui County	45	30	75
Lanai City, Lanai	18	6	24
Wailuku, Maui	19	12	31
Kaunakakai, Molokai	8	12	20
Total	141	75	216

178 There were some stakeholders that participated at multiple workshops.

Figure 55. Ownership model workshop participants

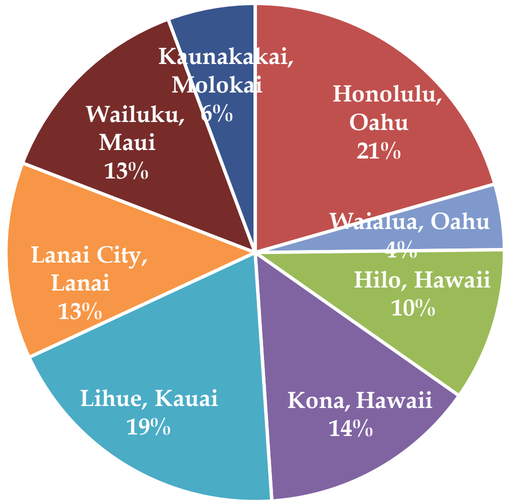
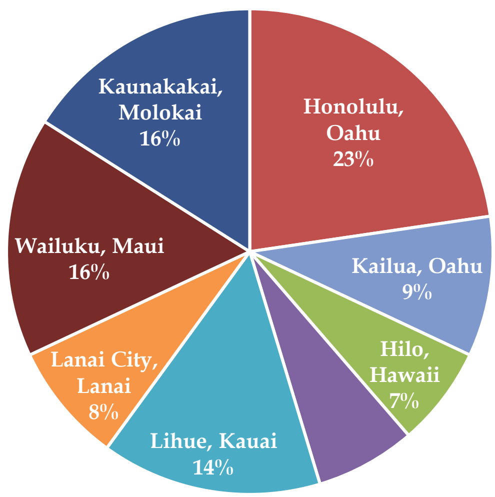


Figure 56. Regulatory model workshop participants



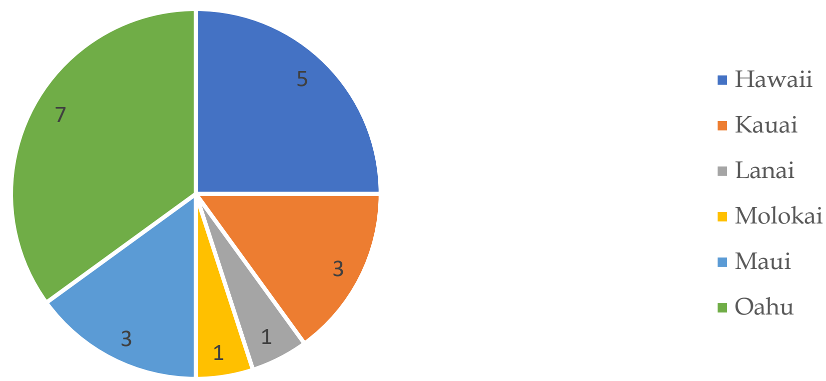
8.2.1 VERGE workshops

The Project Team conducted two workshops at VERGE Hawaii in Honolulu, one in June 2017 and one in June 2018. Unfortunately, many participants did not sign in at these workshops. There were more than 100 participants at each workshop.

8.2.2 Bilateral meetings

Throughout the project, multiple bilateral meetings were conducted with stakeholders across the state. The primary bilateral meetings were conducted in person in association with the ownership and regulatory workshops.

Figure 57. Bilateral meetings in conjunction with ownership model community outreaches, by island



In conjunction with the regulatory workshops, the Project Team met with stakeholders representing 15 organizations (see

Figure 59 and Figure 60). Additionally, the Project Team met or spoke with 24 stakeholders during the summer of 2017 to discuss the project and receive feedback (see Figure 61 and Figure 62).

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Figure 58. Bilateral meetings in conjunction with Ownership Model community outreaches, by Organization Type

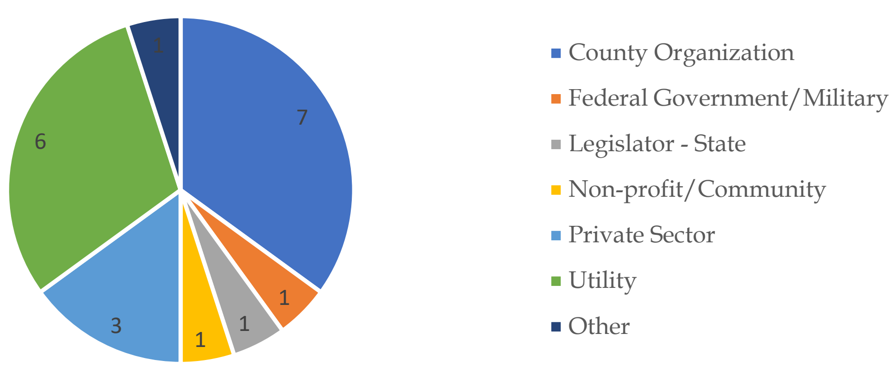


Figure 59. Bilateral Meetings in Conjunction with Regulatory Model Workshops, by Island

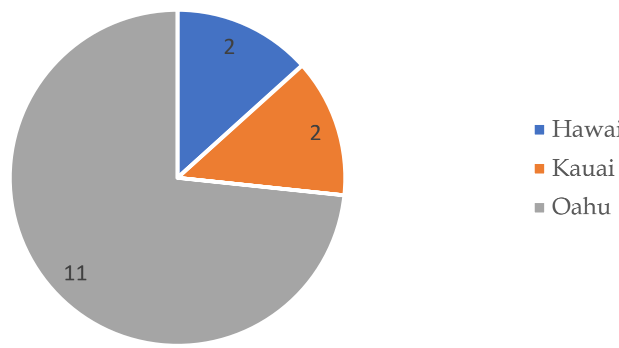


Figure 60. Bilateral Meetings in Conjunction with Regulatory Model Workshops, by Organization Type

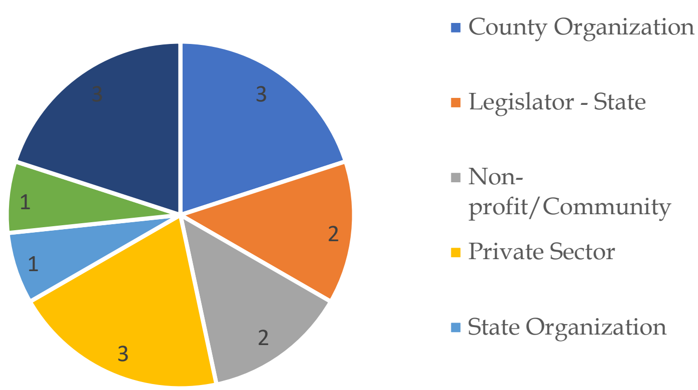


Figure 61. Bilateral Meetings Conducted in June and July 2017, by Island

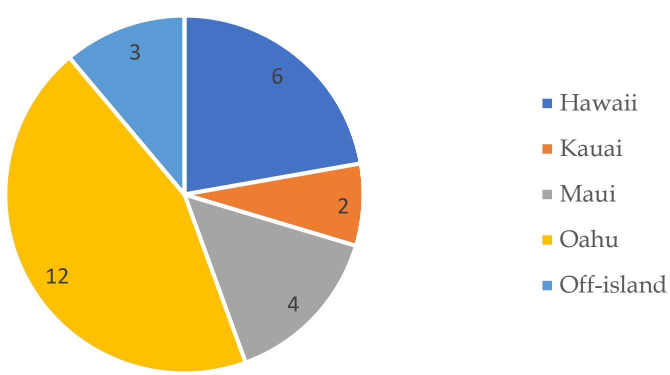
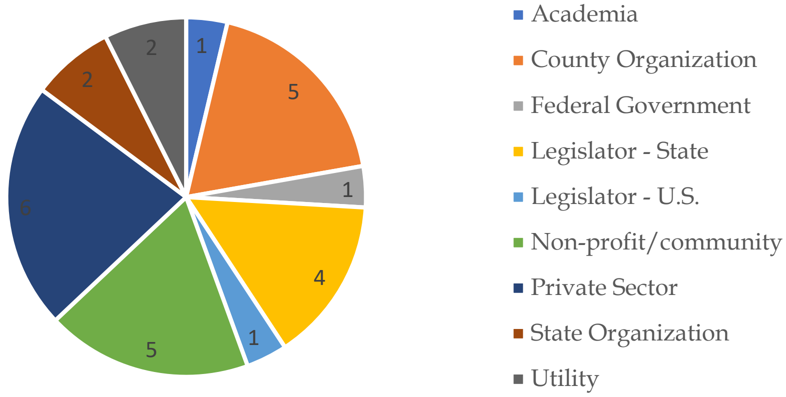


Figure 62. Bilateral Meetings Conducted in June and July 2017, by Organization Type



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

4.1.5 Final formal professional report documenting analyses, incorporating feedback from public meetings in TASK 4.1.4.

CONTRACTOR shall prepare a final draft of the formal professional report with detailed reporting of all research, analysis, and findings of all tasks and subtasks in accordance with the STATE approved detailed outline and incorporating feedback from the public meetings conducted in TASK 4.1.4.

DELIVERABLE FOR TASK 4.1.5. CONTRACTOR shall provide a final draft of the formal professional report with detailed reporting of all research, analysis, and findings of all tasks and subtasks in accordance with the STATE approved detailed outline; incorporating feedback from the presentations conducted in TASK 4.1.4. Deliverable shall include the final formal professional report documenting the analyses and results of all tasks. CONTRACTOR shall provide five professionally bound hard copies and an electronic copy in both MS Word and PDF formats of the Final Report. CONTRACTOR shall submit deliverable for TASK 4.1.5 to the STATE for approval.

10 Appendix C: About the Project Team

10.1 London Economics International

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. The firm's roots stem from the initial round of privatization of electricity, gas, and water companies in the UK in the late 1980s. Since then, LEI has advised private sector clients, market institutions, and government on policy initiatives, market and tariff design, asset valuation, market power, and strategy in virtually all deregulated markets worldwide.

The following attributes make LEI unique:

- ***clear, readable deliverables*** grounded in substantial topical and quantitative evidence
- ***extensive experience in regulatory filings*** provides expertise to advise on network tariffs and design rates under PBR
- ***wealth of knowledge of energy and infrastructure regulation*** worldwide to provide expert testimony services on regulatory best practices and innovation
- ***balance of private sector and governmental clients*** enables us to advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions
- ***Boston-based firm*** with in-depth knowledge of energy policies and regional issues
- ***worldwide experience*** backed by multilingual and multicultural staff.

10.2 Meister Consultants Group, a Cadmus Company

Meister Consultants Group, a Cadmus Company ("MCG-Cadmus"), is an international sustainability consulting firm specializing in renewable energy policy and strategy development. The Cadmus Group is a full-service technical consultancy with a track record of delivering customized solutions to clients that address complex challenges in energy, sustainable transportation, climate, the natural and built environment, public health, homeland security and all-hazard preparedness, and international development. With over 600 employees, Cadmus serves government, commercial, and nongovernmental organizations around the world. Within Cadmus, MCG is a leader in clean energy policy, climate change planning, and stakeholder dialogue with a unique approach that is grounded in global best practices but tailored to local context. MCG-Cadmus is particularly recognized for its expertise in island sustainability and resilience, having worked with over 20 island jurisdictions, including Hawaii.

MCG-Cadmus has been on the forefront of local-level energy, climate, and transportation planning in the U.S. Our energy practice addresses all renewable technologies, including their integration with other sectors, such as transportation and the built environment. Our broader sustainability portfolio with government clients encompasses initiatives ranging from emissions inventory analysis, climate and resilience planning, stakeholder engagement, marketing and education campaigns, energy procurement, sustainability financing strategies, among many others.

10.3 Yamamoto Caliboso, a Limited Liability Law Company

Yamamoto Caliboso is a boutique law firm in Honolulu, Hawaii, which concentrates on helping clients with corporate, energy, financing, real estate, regulatory and public utility law.

Yamamoto Caliboso has one of Hawaii's largest law practices in the area of renewable energy, with industry-leading experience representing independent power producers. Clients include developers of wind, solar, hydro, biomass, and biofuel projects. Yamamoto Caliboso also works with buyers and sellers in the distributed generation industry.

Yamamoto Caliboso handles regulatory matters for clients in the energy, telecommunications, water, sewer, cable and transportation industries, with a particular focus on issues involving the Hawaii Public Utilities Commission. Yamamoto Caliboso serves as regulatory counsel for most of Hawaii's utility-scale independent power producers, as well as for key players in the telecommunications industry.

11 Appendix D: List of documents consulted

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