Technical Appendices

Alternative Fuel, Repowering, and Energy Transition Study

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Appendix A - Fuels Evaluation

Criteria and Basis of Evaluation

This Technical Documentation presents the basis of fuel evaluation for the Alternative Fuel and Energy Transition Study starting with the identification of the fuel, whether it is imported or sourced locally, and then providing an overall evaluation score as well as individual scores for technology readiness levels (TRLs), transportation logistics, fuel geographic availability, and scalability. Ratings are explained in this section with fuels and their evaluations presented individually.

Fuel Name – Fuel Pathway: Name of Fuel – Imported or Local

Definition: Description of the fuel using references from HSEO, Hawaiian Electric Company, Inc. (HECO), and other reports.

Evaluation Score: Total score based on 1 to 5 scoring adjusted to weighting percentages shown in the following table.

Criteria	Weighting
TRL	30%
Transportation	15%
Fuel Availability	20%
Scalability (production)	35%

TRL: Evaluation of the maturity of the technologies in the fuel supply chain. This criterion indicates a technology risk where the technology has not reached maturity. The higher the TRL the lower the technology risk. HDR assigned values of 1 to 5 where 5 is the most mature technology and 1 is the least mature technology further outlined in the table below.

Level	Description
1	Basic principles observed and reported
2	Proof of concept
3	Technology validated and early prototype demonstration.
4	Technology operational at limited commercial scale
5	Proven at a commercial scale, technology is widely available and operational.

Transportation Logistics: Evaluation of the maturity of the fuel transportation mechanisms. HDR assigned values of 1 to 5 where 5 is the most mature transportation mechanism and 1 is the least mature transportation mechanism further outlined in the table below.

Level	Description
1	Innovation and investment required to transport and distribute fuel
2	Transportation logistics concept proven
3	Transportation logistics validated and early stage of implementation planning.
4	Transportation logistics operational at prototype scale
5	Transportation logistics and infrastructure exist, are operational and proven.

Fuel Availability: Evaluation of the current availability of the requisite volumes of fuel. Evaluation is based on the supply and demand of the fuel. HDR assigned values of 1 to 5 where 5 is high volumes of fuel are commercially available and 1 is limited volumes commercially available as further outlined in the table below.

Level	Description
1	Limited volumes available commercially
2	Small volumes available commercially
3	Moderate volumes available commercially
4	Large volumes available commercially
5	Abundant volumes available commercially with little or no constraints

Scalability: Evaluation of fuel capacity to meet energy demands. HDR assigned values of 1 to 5 where 5 can scale to meet the upper thresholds of power demands and 1 indicates no capacity to scale to meet energy demands.

Level	Description
1	No capacity to scale up, current fuel is at maximum capacity and availability, ability to produce volumes is severely constrained
2	Limited capacity to scale, and produce limited volumes due to constraints (feedstock, space, etc.)
3	Moderate capacity to scale up
4	Capacity to scale up at large volumes with some risk
5	Capacity to scale up at large volumes with minimal constraints

References: Links to reference information used in the evaluation.

Fuel Details

This section identifies and describes evaluation results for the fuels identified and studied in the Fuel Matrix, including various forms of methane, diesel, hydrogen, methanol, and ammonia.

Methane – Imported Liquefied Natural Gas (LNG)

Definition: Methane is the largest component of natural gas, a fossil fuel energy source. Natural gas is stored and transported in its liquid state (LNG) to increase the volumetric density.

Evaluation Score: 5.00

TRL: 5. LNG has a fully developed supply chain with production, shipping, and consumption technology readily available. For over 60 years, LNG has been produced, stored, and transported all over the world. The key components of the proposed LNG supply chain are the LNG container ship, floating storage regasification unit (FSRU), subsea pipeline, onshore pipelines, bullet tanks, and International Organization for Standardization (ISO) containers. This equipment has been implemented internationally in a similar manner successfully. Similarly, other associated technologies has been widely studied, developed, and utilized in many similar applications to meet the growing energy demand. With the long history of LNG comes a high level of maturity in both technology and supply chain feasibility.[1]

An example of a similar solution currently in operation is Northeast Gateway Deepwater Port, a project by the company Excelerate. This project was commissioned in 2008 and consists of an FSRU moored about 13 miles off Massachusetts Bay equipped with a subsea pipeline.[2] As with any project, there are location-specific variables and environmental considerations that need to be addressed.

Transportation Logistics: 5. LNG can be shipped on ocean-going vessels that deliver LNG directly to shore or a moored FSRU. LNG is shipped at cryogenic temperatures, and LNG vessels are widely available. Little innovation is required to transport LNG. Several commercial avenues exist currently in the market for turnkey LNG sourcing. Providers such as Excelerate would source, ship, and provide the FSRU in a turn-key arrangement.

Storage volumes for LNG container ships and FSRU can be optimized to meet the demand for the location they serve. Additionally, the vaporization technology can provide a range of flow rates for the natural gas via the subsea pipeline. Again, the long history of LNG transportation and flexibility provides multiple examples of logistical solutions meeting demands and confirming resilient and firm energy generation.

Fuel Geographic Availability: 5. LNG is not currently produced in Hawai‘i, but could be sourced from Canada or Australia among other locations including the United States. Requisite volumes to meet the energy demand are available in both Canada and Australia with little constraints to volume production currently.

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[1] EIA. Natural gas explained. US EIA. https://www.eia.gov/energyexplained/natural-gas/liquefied-natural-gas.php

[2] Excelerate Energy. (2024). *Northeast Gateway Deepwater Port*. Retrieved from https://excelerateenergy.com/projects/northeast-gateway-deepwater-port/

If LNG is sourced from the United States, additional consideration to Jones Act compliance is necessary. As of today, there are no large-scale Jones Act-compliant LNG vessels currently in operation as the United States has not built a standard-size LNG ship in America since the early 1980s. Currently, there are only a few small-scale Jones Act-compliant LNG vessels that are used for LNG bunkering/refueling and are not large enough to deliver LNG cargo to Hawaiʻi.[3]

Scalability: 5. LNG can be purchased and shipped. Natural gas is not currently used in Hawaiʻi at large volumes; however, synthesis gas (syngas) is. Natural gas could replace syngas or other gaseous fuel sources on the islands. The Institute for Energy Economics and Financial Analysis expects global LNG supply capacity to rise to 666.5 million tons per annum by the end of 2028, which exceeds International Energy Agency demand scenarios through 2050; therefore, there is adequate LNG capacity to meet Hawaiʻi's power needs.[4]

Diesel – Local Biodiesel and Renewable Diesel

Definition: Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil. Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.

Evaluation Score: 2.85

TRL: 5. Biodiesel is currently produced in Hawaiʻi and the production capacity could be increased with increased feedstock. The production technology is proven and commercially available in Hawaiʻi.

Transportation Logistics: 5. Pure biodiesel has limited direct-use applications and supply logistics challenges because of its physical properties and characteristics. Biodiesel is a good solvent, which means it can degrade rubber in fuel lines and loosen or dissolve varnish and sediments in petroleum diesel fuel tanks, pipelines, and engine fuel systems, which can clog engine fuel filters. Biodiesel turns into a gel at higher temperatures than petroleum diesel, which creates problems for its use in cold temperatures. So, certain biodiesels cannot be stored or transported in regular petroleum liquid tanks and pipelines—they must be transported by rail, vessel, and barge, or truck.[5]

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[3] Facts Global Energy (2024) Economics of Accelerating Hawaiʻi's Energy Transition via LNG and other Alternative Fuels. Prepared for the Hawaiʻi State Energy Office.

[4] The Institute for Energy Economics and Financial Analysis. (2024, November 25). Global LNG Outlook 2024-2028. Global LNG Outlook 2024-2028 | IEEFA

[5] EIA. (2024, February 1). Biofuels explained: Biodiesel, renewable diesel, and other biofuels. https://www.eia.gov/energyexplained/biofuels/biodiesel-rd-other-use-supply.php

Fuel Geographic Availability: 1. Currently, there is one refinery in Hawaiʻi that produces biodiesel: Pacific Biodiesel. This refinery has a nameplate capacity of 5.5 million gallons (MMGAL) per year, and in 2023, it produced 6 MMGAL. Most of the feedstock comes from waste oils and fats with local production supplemented by imported oils and fats (tallow). The most frequently used oils in Pacific Biodiesel's production are used cooking oil, tallow, yellow grease, poultry grease, cottonseed oil, and soybean oil. [6]

Scalability: 1. There are already six power plants across the island that can run on biofuel[7], but changing to biodiesel for fuel at these plants would require additional production of biodiesel in large quantities.

Based on previous studies, one of the highest-yielding crops for biodiesel and renewable diesel production in Hawaiʻi is palm oil, which also has had initial production testing. In the 2013 HNEI Biofuels Development crop assessment report initial production testing in Hawaiʻi showed palm oil yields of 620 to 650 gallons per acre.[8] On average exhibits yields (gal/acre) estimated to be approximately six to ten (6-10) times higher than camelina, approximately six (6) times higher than sunflower, five (5) times higher than rapeseed/canola, thirteen (13) times higher than soy, and about three (3) times higher than that of Jatropha.[9],[10] Noting annual yield is influenced by the number of harvests per year that can be reasonably completed. Palm oil only served as the most optimistic baseline to estimate scalability, when considering other crops, land use intensity would increase, further decreasing the overall scalability score.

There are also tradeoffs between economic sectors to consider as Hawaiʻi looks to decarbonize the entire economy. Liquid biofuels can be used for electric generation, but they can also be used as a low-carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels since hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there will likely be competing demands for biofuel production from other sectors that may be more likely and willing to pay a premium for the fuel or feedstock. The 2022 Inflation Reduction Act (IRA) provides substantial tax credits to support the domestic production of clean transportation fuels, including sustainable aviation fuel (SAF). These incentives are aimed at enhancing the cost-competitiveness of biofuels in the transportation sector, potentially leading to favored use in transportation instead of electricity generation.

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[6] Pacific Biodiesel Frequently Asked Questions. (n.d) Retrieved from biodiesel.com/faq/

[7] Hawaiian Electric Companies. (2024, January 31). Fuels Master Plan. Page 9 of 60.

[8] Hawaiʻi Natural Energy Institute (2013) Hawaiʻi Energy and Environmental Technologies Initiative, Alternative Biofuels Development: Crop Assessment.

[9] Id

[10] Pacific Biodiesel Technologies (2017). *Biofuel Crop Fact Sheet.* Retrieved from https://biodiesel.com/wp-content/uploads/2020/01/Biofuel-Crop-Fact-Sheet-2-24-17-FINAL.pdf

While locally produced biofuels cannot be scaled to meet Hawaiʻi's energy demand, they are still important to pursue in a balanced manner as they can provide substantial co-benefits for agriculture, have strong potential to reduce emissions if grown regeneratively, and can offset some of the state's fuel demand.

General Notes: From HECO's Fuels Master Plan, the cost of biodiesel is typically two to three times more than LSFO.[11]

Imported Biodiesel and Renewable Diesel

Definition: Biodiesel and renewable diesel can both be used as a combustion energy source though there are distinct differences in these "renewable" fuels. Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil.

Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.

Further supply of biodiesel to meet renewable energy and climate goals would either have to come through new supply sources or imports. Several previous studies have looked at biofuel production in Hawaiʻi with the most relevant and complete studies being a Black and Veatch study in 2010, *The Potential for Biofuels Production in Hawaiʻi,* and a Hawaiʻi Agricultural Research Center (HARC) study from 2006, *Biodiesel Crop Implementation in Hawaiʻi*. These studies provide a good fundamental understanding of the potential for biodiesel production within the state of Hawaiʻi as well as potential limitations.

Evaluation Score: 3.00

TRL: 5. Biodiesel and renewable diesel production has been steadily increasing since 2007. Commercially viable production pathways exist off-island.

Transportation Logistics: 5. Biodiesel could be shipped similarly to petroleum diesel and LSFO that the island currently uses. Infrastructure on the island exists with LSFO pipelines and feeds to power plants. Additional pipelines might be required.

Fuel Geographic Availability: 2. Renewable and biodiesel demand can also be met with imported fuels and feedstocks. Biodiesel production sources are typically geared toward specific markets with the bulk of the United States' current biodiesel production coming from soybean oil, Europe utilizing rapeseed oil, and southeast Asia favoring palm oil.

[11] Hawaiian Electric Companies. (2024, January 31). Fuels Master Plan. Page 5 of 60.

Indonesia and Malaysia dominate palm oil production accounting for greater than 80% of global production. This production also supports renewable diesel production abroad with almost all renewable diesel imported to the United States currently coming from a Neste facility in Singapore. The United States also receives smaller supplies of biodiesel from Canada, Germany, Spain, and Italy. Import options for Hawaiʻi are likely to be Southeast Asian due to proximity and cost.

Scalability: 1. The United States is a current net importer of biofuels and its current biodiesel production capacity sits at about 2,000 MMGAL[12]; however, US production capacity has been steadily decreasing since its peak capacity of 2,600 MMGAL in July 2019.[13] For comparison, Hawaiʻi consumed a combined 497 MMGAL per year of LSFO, high sulfur fuel oil, diesel, and naphtha fuels.[14] HECO's latest request for proposal for biodiesel imports to Hawaiʻi was for 285,000 barrels per year or about 12 MMGAL per year.[15] To replace a meaningful percentage of 497 MMGAL per year of fossil-based fuel oil, Hawaiʻi will have to compete for biofuels with states like California that have financial incentives to consume biofuels and midwestern states like Iowa, where customers would benefit from shorter shipping distances. Based on these challenges, Hawaiʻi is likely to source imported biofuels from southeast Asia due to proximity and cost.

Diesel – Local E-Diesel or Synthetic Diesel

Definition: E-diesel is a synthetic diesel fuel that can be produced from carbon dioxide, water, and electricity. E-diesel can also be synthesized from carbon-containing feedstocks, such as natural gas or coal.[16]

Evaluation Score: 1.75

TRL: 2. The production of e-diesel through the Fisher-Tropsch process has been around for about 100 years but is still only used by a few companies and is not available on island.

Transportation Logistics: 4. Existing infrastructure exists on island to transport e-diesel to power generation facilities. Minor upgrades to pipelines would be required to transport the volumes required.

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[12] US Biodiesel Plant Production Capacity. EIA. (2024, August 15). https://www.eia.gov/biofuels/biodiesel/capacity/

[13] EIA. (2024, September 10). Petroleum & Other Liquids. US biodiesel production capacity (MMGAL). https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M

[14] Data from Hawaiian Electric. (January 31, 2024). Consolidated Annual Fuel Report, DKT 2022-0014, Page 10 of 60. HDR calculations using assumption that 1 barrel is equivalent to 42 US gallons.

[15] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

[16] Majewski, A. (2023, August 1). Synthetic Diesel Fuel. Synthetic diesel fuel. https://dieselnet.com/tech/fuel_synthetic.php

Fuel Geographic Availability: 1. Feedstocks (natural gas or coal) are not readily available on the island. E-diesel production requires significant electricity, which is a resource that is already in high demand.

Scalability: 1. E-diesel can be used as a drop-in fuel for existing diesel engines; however, the process is expensive and requires large amounts of electricity and potentially carbon-containing feedstocks.

Diesel – Imported E-Diesel or Synthetic Diesel

Definition: E-diesel is a synthetic diesel fuel refined from crude oil produced from carbon dioxide, water, and electricity. E-diesel can also be synthesized from carbon-containing feedstocks, such as natural gas or coal.[17]

Evaluation Score: 2.05

TRL: 4. The production of e-diesel has been around for about 100 years but is still only used by a few companies and is not available on island.

Transportation Logistics: 2. E-diesel could be shipped similarly to other diesel fuels; however, it is not shipped in mass today.

Fuel Geographic Availability: 1. In the current market, the volumes of e-diesel that would be needed are not available.

Scalability: 1. E-diesel can be used as a drop-in fuel for existing diesel engines; however, the process is expensive and requires large amounts of electricity and potentially carbon-containing feedstocks.

Methane – Local Biomethane or Local Renewable Natural Gas (RNG)

Definition: RNG can be generated from various sources, including biogas obtained from wastewater plants, landfills, organic waste, and lignocellulosic materials. RNG can be used where the gas is created (landfills or wastewater plants) or it can be injected into natural gas transmission or distribution pipelines.

Evaluation Score: 3.15

TRL: 5. The technology used to manage methane produced in a landfill is relatively simple; however, it is very costly, and often cost-prohibitive particularly for established landfills unless the capture system is in place.[18]

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[17] Majewski, A. (2023, August 1). Synthetic Diesel Fuel. Synthetic diesel fuel. https://dieselnet.com/tech/fuel_synthetic.php

[18] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 125.

Transportation Logistics: 5. If locally produced, RNG could be integrated into existing infrastructure.

Fuel Geographic Availability: 1. Hawaiʻi Gas currently blends RNG in its utility gas line and is working to further expand this practice.[19] Notably, one of the incentives for RNG suppliers is the state's Renewable Fuels Production Tax Credit. Pursuant to Hawaiʻi Revised Statute §269-45, Hawaiʻi Gas is required to report the percentage of feedstock comprised of petroleum feedstock and the percent comprised of non-petroleum feedstock. In 2023, around 1.5% (329,269 therms) of Hawaiʻi Gas' feedstock was from recovered biogas at the Honouliuli wastewater treatment plant.[20]

To date, there are no landfill gas (LFG) waste-to-energy systems in Hawaiʻi – methane is either flared from LFG collection systems in place or slowly released into the atmosphere at landfills without LFG capture systems in place. Hawaiʻi has seven operating landfills to date, only three of which have LFG capture systems in place.[21]

The Honolulu Program of Waste Energy Recovery (H-POWER), owned by the City and County of Honolulu, already utilizes 3,000 tons per day (TPD) of garbage on Oʻahu for steam rather than RNG.

Scalability: 1. Hawaiʻi could expand the use of RNG for power production to a figure of 673,888 MWh/year which would be approximately 6 percent of the state's non-renewable electrical consumption[22] and roughly 74% of that production comes from the thermal conversion of urban fiber wastes. Without that feedstock, the total electrical production potential is only 178,132 MWh/year and less than 2% of the total for the state. Considering land use and economic constraints, RNG may be put to higher use in harder-to-decarbonize sectors like transportation, heavy-duty equipment at ports, airports, and other areas.

Methane – Imported Biomethane or RNG

Definition: RNG can be generated from various sources, including biogas obtained from wastewater plants, landfills, organic waste, and lignocellulosic materials.

Evaluation Score: 2.90

TRL: 5. RNG technology is a reliable technology but expensive to implement.

Transportation Logistics: 2. RNG could be shipped; however, RNG is not currently shipped at scale.

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[19] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 98.

[20] The Gas Company, LLC. Hawaiʻi Revised Statutes (HRS) §269-45, Gas Utility Companies Renewable Energy Report. (April 1, 2024). Retrieved from https://puc.hawaii.gov/reports/energy-reports/renewable-energy-annual-report-gas/

[21] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 126.

[22] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Fuel Geographic Availability: 2. The United States currently produces RNG as a supplement to a large NG demand domestically, but exportation of RNG internationally is becoming attractive and driven by regulatory initiatives in Europe.

Scalability: 2. Considering land use and economic constraints, RNG may be put to higher use in harder to decarbonize sectors like transportation, heavy duty equipment at ports, airports, and other areas. RNG can be used as a direct replacement to natural gas. EIA estimates in 2022 about 216 billion cubic feet (Bcf) of LFG was collected at 334 US landfills. LFG was burned to generate about 8.5 billion kilowatt-hours (kWh) of electricity or about 0.2% of total US utility-scale electricity generation in 2022. EIA estimates in 2022, 23 dairies and livestock operations with anaerobic digesters in the United States produced about 0.1 billion (121 million) kWh of electricity from biogas. RNG is typically consumed near the sites of production , or blended into utility gas lines. Based on current production levels, scaling up US production to a level where large scale liquefaction and shipping would be feasible is unlikely.[23]

Methane – Local E-Methane or Synthetic Natural Gas (SNG)

Definition: E-methane and SNG is a manufactured product chemically similar in most respects to natural gas. SNG results from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas. SNG can be synthesized using renewable energy.[24]

Evaluation Score: 2.55

TRL: 4. Utility gas service is already serviced by SNG.[25] However, Hawai‘i would be looking at renewable SNG and that technology is under development.

Transportation Logistics: 4. Utility gas service is only on O‘ahu, primarily in the urban core.[26]

Fuel Geographic Availability: 2. Hawai‘i Gas produces SNG from naphtha supplied by the Par Hawai‘i refinery.[27]

Scalability: 1. Hawai‘i Gas is seeking lower carbon alternatives to SNG.[28]

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[23] Biomass explained. Biogas-Renewable natural gas - US EIA. https://www.eia.gov/energyexplained/biomass/landfill-gas-and-biogas.php

[24] Alverà, M. (2024, January 9). Your guide to e-NG: The green natural gas alternative that could revolutionize the green transition. World Economic Forum. https://www.weforum.org/stories/2024/01/eng-synthetic-natural-gas-decarbonize-shipping/

[25] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238.

[26] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 97.

[27] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 97.

[28] HSEO. (2023). Hawai‘i Pathways to Decarbonization, Act 238, Page 98.

Methane – Imported E-Methane or SNG

Definition: E-methane and SNG is a manufactured product chemically similar in most respects to natural gas. SNG results from the conversion or reforming of hydrocarbons that may easily be substituted for or interchanged with pipeline-quality natural gas. E-methane is a version of SNG that can be produced from hydrogen.[29]

Evaluation Score: 2.65

TRL: 5. Producing SNG from carbon feedstock is a vetted technology. Producing green SNG from hydrogen and carbon dioxide is still at an advanced research and development level.

Transportation Logistics 4. SNG can be liquified or compressed as a gas for transport.

Fuel Geographic Availability: 1. Renewable SNG is not currently available for purchase in large quantities.

Scalability: 1. Hawaiʻi Gas is seeking lower carbon alternatives to SNG.[30] The global SNG market demand was estimated at 230.05 million normal meter cubed per hour in 2023 and is expected to grow at a compound annual growth rate of 11.3% from 2024 to 2030.[31]

Hydrogen – Local Green Hydrogen

Definition: Green hydrogen is produced from the electrolysis of water with the electricity sourced from renewable energy.[32] It can also be produced via waste or biomass gasification or pyrolysis.[33]

Evaluation Score: 2.60

TRL: 3. Electrolysis at scale in Hawaiʻi is not yet cost efficient, but technology innovation is worth tracking over the next two decades.[34]

Transportation Logistics: 4. For on-island hydrogen production existing transport systems are operational at prototype scale. Interisland transport of hydrogen (e.g. production on Hawaiʻi Island, where land availability is less constrained, for consumption on Oʻahu) presents logistical challenges, including the need for specialized shipping infrastructure such as high-pressure storage tanks or cryogenic systems to safely transport liquefied hydrogen. Additionally, the costs

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[29] Alverà, M. (2024, January 9). Your guide to e-NG: The green natural gas alternative that could revolutionize the green transition. World Economic Forum. https://www.weforum.org/stories/2024/01/eng-synthetic-natural-gas-decarbonize-shipping/

[30] HSEO. (2023). Hawaiʻi Pathways to Decarbonization, Act 238, Page 98.

[31] Grand View Research. Syngas Market Size & Trends. Syngas Market Size, Share, Growth & Trends Report, 2030. https://www.grandviewresearch.com/industry-analysis/syngas-market-report

[32] Department of Energy. (n.d.-a). Hydrogen Production: Electrolysis. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

[33] HSEO. (2023). Hawaiʻi Pathways to Decarbonization, Act 238.

[34] Hawaiʻi State Energy Office. (2023). Hawaiʻi Pathways to Decarbonization, Act 238.

and energy requirements for compression or liquefaction, along with potential losses during transportation, add complexity to ensuring a reliable and efficient supply chain between islands.

Fuel Geographic Availability: 2. Feedstocks for hydrogen production would be electricity and water, two resources already in heavy demand. Hawaiʻi released a request for proposal for suppliers of renewable hydrogen.[35]

Scalability: 2.

Hydrogen would run on dedicated equipment and pipelines or be integrated into a natural gas blend. Scaling up green hydrogen in Hawaiʻi would also require a surplus of renewable energy to power electrolysis plants. Pipelines and equipment capable of accommodating 100% hydrogen are limited, as conventional infrastructure often lacks the materials needed to prevent hydrogen embrittlement and leakage, necessitating significant investments in upgrading or replacing existing systems to ensure safety and efficiency. These improvements and upgrades are anticipated to become more cost-effective in the near future.

Hydrogen – Using Ammonia as a carrier

Definition: Imported green hydrogen is produced from electrolysis powered by renewable energy. This hydrogen could be shipped as liquid hydrogen or liquid ammonia. Liquid ammonia would need catalytically cracked into hydrogen gas.

Evaluation Score: 3.15

TRL: 3. Green hydrogen is currently being studied with heavy federal investment. Ammonia technology has been identified as a hydrogen carrier with invested interest.[36]

Transportation Logistics: 3. There are no current vessels shipping liquid hydrogen at scale. There are vessels currently shipping ammonia. Shipping liquid hydrogen is challenging due to the extremely low boiling temperature and energy density.[37]

Fuel Geographic Availability: 2. There is investment in new-build hydrogen and ammonia facilities; however, green hydrogen and ammonia cracking facilities are relatively new.

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[35] Hawaiʻi Gas. (2023, September 30). 2023 Request for Proposals. Hawaiʻi Gas

[36] US Department of Energy. (2006, February 1). Potential Roles of Ammonia in a Hydrogen Economy. Potential Roles of Ammonia in a Hydrogen Economy

[37] Qianqian Song, Rodrigo Rivera Tinoco, Haiping Yang, Qing Yang, Hao Jiang, Yingquan Chen, Hanping Chen, A comparative study on energy efficiency of the maritime supply chains for liquefied hydrogen, ammonia, methanol and natural gas, Carbon Capture Science & Technology, Volume 4, 2022, (https://www.sciencedirect.com/science/article/pii/S2772656822000276)

Scalability: 4. With the increased investment in research and development for hydrogen as a fuel, there is optimism for hydrogen use as a fuel. If programs like the US Department of Energy Hydrogen Shot succeed, prices for hydrogen will drop significantly.[38] Further, hydrogen could be integrated into existing natural gas infrastructure including piping and turbines.

Methanol – Local E-Methanol

Definition: E-methanol or renewable methanol can be produced using renewable energy and renewable feedstocks via two routes. Bio-methanol is produced from biomass. Green e-methanol is obtained by using carbon dioxide captured from renewable sources (i.e., bioenergy with carbon capture and storage and direct air capture) and green hydrogen (i.e., hydrogen produced with renewable electricity).[39]

Evaluation Score: 1.90

TRL: 2. The cost of renewable methanol production is currently high, and production volumes are low. With the right policies, renewable methanol could be cost-competitive by 2050 or earlier.[40]

Transportation Logistics: 5. Locally produced.

Fuel Geographic Availability: 1. Potential feedstocks would be forestry and agricultural waste and by-products; biogas from landfill, sewage, and municipal solid waste; and black liquor from the pulp and paper industry.

Scalability: 1. Feedstocks for local E-methanol are limited.

Methanol – Imported E-Methanol

Definition: E-methanol or renewable methanol can be produced using renewable energy and renewable feedstocks via two routes. Bio-methanol is produced from biomass. Green e-methanol is obtained by using carbon dioxide captured from renewable sources (i.e., bioenergy with carbon capture and storage and direct air capture) and green hydrogen (i.e., hydrogen produced with renewable electricity).[41]

Evaluation Score: 1.60

TRL: 2. The cost of renewable methanol production is currently high, and production volumes are low. With the right policies, renewable methanol could be cost-competitive by 2050 or earlier.[42]

[38] Department of Energy. (n.d.). Hydrogen Shot. Hydrogen Shot | Department of Energy

[39] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - Renewable Methanol

[40] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[41] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[42] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

Transportation Logistics: 3. E-methanol is a liquid at atmospheric pressure and can be stored much like bunker fuel.[43]

Fuel Geographic Availability: 1. Less than 0.2 metric tons (Mt) of e-methanol is produced annually, mostly as bio-methanol. [44]

Scalability: 1. E-methanol is not currently produced at large scales.

Ammonia – Local E-Ammonia

Definition: E-Ammonia (Green or Renewable Ammonia) is produced from renewable hydrogen, which, in turn, is produced via water electrolysis using renewable electricity. This hydrogen is converted into ammonia using nitrogen that is separated from air.[45]

Evaluation Score: 1.30

TRL: 1. In the last decade, attempts to use ammonia in internal combustion engines and gas turbines have considerably increased. IHI, Mitsubishi, and GE have had successful field tests of liquid ammonia combustion turbines. Industrial production is shifting toward renewable ammonia. The annual manufacturing capacity of announced renewable ammonia plants is 15 Mt by 2030 (around 8% of the current ammonia market across 54 projects, notably in Australia; Mauritania, Africa; and Oman, West Asia). A pipeline of 71 Mt exists out to 2040, but investment decisions are still pending for most projects.[46]

Transportation Logistics: 3. Produced on island but would need hydrogen for production.

Fuel Geographic Availability: 1. Would be available depending on hydrogen sourcing. Hydrogen sourcing on island would be limited for use in creating e-ammonia.

Scalability: 1. Since e-ammonia relies on hydrogen as a feedstock and that hydrogen would need produced on-island from a renewable energy source. Local feedstock to scale up is not available.

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[43] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[44] IRENA. (2021). Innovation Outlook: Renewable methanol. IRENA - IRENA - Renewable Methanol

[45] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[46] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

Ammonia – Imported E-Ammonia

Definition: E-Ammonia (Green or Renewable Ammonia) is produced from renewable hydrogen, which, in turn, is produced via water electrolysis using renewable electricity. This hydrogen is converted into ammonia using nitrogen that is separated from air.[47]

Evaluation Score: 2.05

TRL: 1. In the last decade, the attempts to use ammonia in internal combustion engines and gas turbines have considerably increased. Industrial production is shifting toward e-ammonia.

Transportation Logistics: 3. Anhydrous ammonia is currently shipped in a similar method to LNG.

Fuel Geographic Availability: 3. Ammonia is produced mainly in Asia, which has more than half of the global ammonia production capacity.[48] There is some momentum to build new hydrogen-to-ammonia plants, especially in Australia.[49] However, it remains to be seen if these plants come to fruition and if they have any impact on e-ammonia fuel supply.

Scalability: 2. Ammonia for fuel consumption doesn't have the same funding and research and development compared to hydrogen. However, due to the transportation and storage challenges of hydrogen, e-ammonia may gain investment traction in the future.

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[47] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[48] International Renewable Energy Agency. (2022). Innovation Outlook Renewable Ammonia. Innovation Outlook - Renewable Ammonia

[49] Valentini, A. (2021). The market for Green Ammonia: Future potential and hurdles. Market for Green Ammonia

Appendix B - Power Plant Repowering & Replacement

Hawaiʻi currently relies on a mix of fuel sources for electricity generation. For firm capacity sources, the islands primarily rely on a combination of petroleum liquids including LSFO, Ultra Low Sulfur Diesel (ULSD), No. 2 Diesel Oil, and Industrial Fuel Oil (IFO) as well as biodiesel.

HDR performed a desktop review of the islands' power plants considering suitability of using natural gas as the primary fuel source. Key considerations for conversion were the age of the existing power plant, the existing rated capacity, the current fuel type, whether there are existing plans for upgrades to renewable fuel sources, and the location of the power plant pertaining to natural gas delivery.

A proposed option for receiving liquefied natural gas (LNG) to Hawaiʻi was to have a floating storage and regasification unit (FSRU) moored offshore at Barbers Point on the southwestern side of Oʻahu. A subsea pipeline would connect the FSRU and the new pipeline network on Oʻahu and deliver fuel to power plants via underground pipelines. See the LNG technical documentation and the Alternative Fuel, Repowering, and Energy Transition Study for more details.

Suitability of Existing Plants for Natural Gas Conversion

Oʻahu

Kahe

Kahe is the largest thermal generating station on the island of Oʻahu at a rated net capacity of 606 megawatts (MW) divided between six LSFO-fired boilers with steam turbine generators (STG). The plant is located along the coast, approximately three miles north of Barbers Point. The plant operates at a relatively high-capacity factor of near 0.5 compared to the other power plants on the island and has a net generation of approximate 2.5 million megawatts-hours (MWh)[50]. The boilers and steam turbines are between 48 and 61 years old and the heat rate of the existing units average around 10,300 British thermal units per kilowatt hour (Btu/kWh). According to Hawaiian Electric Company (HECO),[51] units 1 and 2 are planned for retirement in 2033 and units 3 and 4 in 2037. Units 5 and 6 are not planned for retirement until 2046.

According to available land parcel information and a review of previous studies for natural gas conversion[52], additional power generation equipment could be located on approximately 9 acres adjacent to the existing plant that would be above the tsunami evacuation zones according to

[50] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[51] Hawaiian Electric's Integrated Grid Plan 2023

[52] PUC Docket No. 2016-0137: Kahe Combined Generating Unit

publicly available geographic information system (GIS) data[53]. The ability to operate the existing Kahe boilers during construction of a new power plant would allow HECO to maintain reliability of the grid without shifting load to other plants.

Adding a new power plant at Kahe adjacent to the existing boilers is a potential option for natural gas replacement due to the available space for expansion, and the proximity to the LNG FSRU pipeline described in the introduction above.

Kalaeloa Partners (KPLP)

KPLP is a combined cycle and cogeneration plant with two combustion turbine generators (CTG) and one steam turbine generator (STG) that use heat recovery steam generators (HRSGs) to capture the heat from the CTG exhaust and generate steam for either the STG or for sending process steam to the fuel refinery nearby. The plant is located in the industrial section of Kapolei and there is limited space around the plant for expansion. The rated capacity of the plant is 208 MW and the heat rate is approximately 7,800 Btu/kWh. The plant operates at a relatively high-capacity factor of 0.5 compared to the other power plants on the island and has a net generation of approximately 1.2 million MWh.[54] The two CTGs are GE (formally ABB), model name 11NM each rated at 85 MW.

During discussions with plant staff, HDR determined converting the existing CTGs to run on natural gas using new dual fuel burners rather than replacing with new CTGs would be the preferred option, because the existing CTGs have had regular overhauls and are designed to operate with natural gas. To maintain plant power and steam output, a single CTG and HRSG could be taken offline and converted while the other continues operation during regular planned maintenance.

KPLP is a preferred potential option for natural gas conversion due to the plant having combustion turbine equipment that is capable of being converted with new burners. Additionally, the proximity to the LNG FSRU pipeline described in the introduction above would reduce costs for gas transmission.

Campbell Industrial Park (CIP)

CIP is a single, simple cycle CTG used for addressing the island’s peak loads, and it typically runs at approximately a 0.1 annual capacity factor.[55] The plant was brought online approximately 15 years ago, and its rated capacity is 129 MW with an average heat rate around 11,500 Btu/kWh. The plant is in the industrial section of Kapolei, and there is limited space around it for expansion. The

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[53] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

[54] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[55] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

CTG is a Siemens (formally Westinghouse) W501D5A designed to run on diesel and biodiesel. The W501D5A is likely able to be converted to run on natural gas with new combustors.

Due to the proximity of the decommissioned Barbers Point Coal Plant and KPLP, this unit is a preferred potential option for conversion; however, the total gas usage would not be significant if the plant remains a peaker.

Waiau

The Waiau power plant is a 474 MW power plant with six boilers with STGs and two CTGs. The boilers' ages range between 57 and 77 years old and the CTGs are 51 years old. The plant is located in Pearl City, which is approximately 13 miles east of Barbers Point. The average heat rate of the power plant is approximately 11,400 Btu/kWh, and the total generation of the plant is approximately 905,000 MWh annually.[56] Units 3 and 4 are expected to be retired in 2024, units 5 and 6 in 2029, and units 7 and 8 in 2031[57]. Units 9 and 10 are expected to remain in service throughout the analysis period.

An existing oil pipeline feeds Waiau from the Par Refinery, and a gas pipeline runs from the Par Refinery to neighboring towns and cities. The current gas pipeline is meant for home and business use, and the oil pipeline would need to be retained for backup fuel delivery in addition to not being designed for natural gas service. This existing gas pipeline may be able to supply partial capacity for the plant but would need to be further investigated. Adding another 13-mile pipeline adjacent to the existing pipelines could also be further investigated; however, this was not preferred and considered costly.

HECO's proposed Stage 3 repowering project includes dual fuel combustion turbines that could be used with natural gas, despite being purposed for biodiesel.

H-Power

H-Power is a 68.5 MW waste-to-energy plant that reduces landfill space by burning solid waste for electricity generation. This facility is not feasible for conversion due to its unique role in waste management.

Schofield Generating Station

Schofield Generating Station is a peaking plant located at the Schofield Army Barricks that consists of six reciprocating engines for a total capacity of 49 MW. This plant is approximately five years old and runs on biodiesel. This power plant is not recommended for conversion to natural gas due to the age of the plant, distance from the proposed LNG FSRU pipeline described in the introduction above, and use of biodiesel as a fuel, which meets RPS fuel requirements.

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[56] U.S. Environmental Protection Agency. (2024). Emissions & generation resource integrated database (eGRID) 2022 Dataset.

[57] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

Decommissioned Barbers Point power plant

The Barbers Point Coal Plant was decommissioned in 2022 and is currently being fully demolished. The facility sits on an 8.5-acre plot of land in the industrial section of Kapolei near KPLP and CIP. The property is large enough for a new combined cycle power plant. Its location close to the coast makes it suitable to receive gas from the LNG infrastructure (e.g., FSRU and pipelines) planned at Barbers Point, and existing rights-of-way may be suitable for delivery. Discussions with HECO determined transmission and substation upgrades would be required if a power plant more than approximately 60 MW was built at this location.

Firm Capacity Stage 3 Request for Proposal (RFP) Projects

In 2021, HECO conducted an “all source” procurement process for capacity based on the grid requirements for Oʻahu. HECO awarded the projects described below for the Stage 3 RFP for firm, renewable electricity generation. This study considers the complexities of altering the plant requirements given in the existing proposal, as the projects are already progressing through the RFP process.

Puʻuloa Energy – Ameresco, Inc

HECO selected the Puʻuloa Energy project to provide 99 MW using 11 reciprocating engines operating on biodiesel. This plant will be located on the Pearl Harbor military base, which is about 13 miles east of the proposed LNG FSRU pipeline described in the introduction above. The project is expected to be in service in late 2027. Adding a pipeline could be further investigated; however, this was not preferred and was thought too costly. Future studies could investigate other means of transporting natural gas to this site including utilization of the existing gas line.

Waiau Repower

HECO selected the Waiau Repowering project to provide 253 MW using six CTGs operating on biodiesel. Each CTG is planned to be a 42 MW GE LM6000. The first two units are expected to be in service in 2029 with the next four expected to be in service by 2033[58]. These units are dual fuel and capable of additionally operating on natural gas or hydrogen. As described above, an existing gas pipeline may be able to supply partial capacity for the plant but would need to be further investigated.

KPLP

HECO selected KPLP as a repowering project that will allow the use of biodiesel, which the facility has previously demonstrated to successfully operate on. The units are currently planned to be converted and put into operation in 2033. Based on analysis of biodiesel production and sourcing[59] and discussions with KPLP staff and HECO, HDR decided to consider this site for switching to

[58] Hawaiian Electric’s IGP: 2024 Action Plan Annual Update

[59] See Alternative Fuel, Repowering, and Energy Transition Study

natural gas as its primary fuel. See the above section on KPLP for more information on natural gas operation.

Par Hawaiʻi Renewable Combined Heat and Power

HECO selected Par Refinery in the Stage 3 RFP to provide a 30 MW cogeneration facility powered by biodiesel for commercial operation by 2028. Since Par is the biodiesel source, it is not feasible to have this facility converted to natural gas. Since selection, this project has withdrawn from the Stage 3 Award group citing timeline challenges and delay in supply of combustion turbines.[60]

Hawaiʻi Island

Hill and Kanoelehua

The Hill and Kanoelehua plants are located near each other near Hilo Bay. Hill consists of two boilers running on oil with a capacity of 34 MW. Kanoelehua has 20 MW total with a mix of ULSD-fired boilers and one 10.3 MW, No. 2 diesel-fired CTG. Hill is planned for decommissioning in 2028 and the Kanoelehua Combustion Turbine 1 in 2031[61]. However, the existing 10 MW of Kanoelehua diesels are also more than 45 years old, but not scheduled for decommissioning.

These plants are preferred potential options for natural gas replacement due to the planned decommissioning and proximity to a potential LNG onshore transmission terminal. Additionally, the plant is not in a tsunami inundation zone, so future upgrades can be considered.

Keāhole

The Keāhole plant consists of a 50 MW combined cycle and four peaking units totaling 21 MW run on no. 2 diesel and ULSD. The peaking units are between 35 and 40 years old, and the combined cycle is approximately 15 years old. The combustion turbine (CT2) peaking unit is scheduled to be decommissioned in 2031.

The peaking units at this plant are a preferred potential option for natural gas replacement by replacing the units with new ones due to their old age. Since the combined cycle is more efficient and the units are relatively new, the combined cycle is recommended to remain as oil-fired to keep fuel diversity on the island. The plant is not in a tsunami evacuation zones according to publicly available GIS data[62], so future upgrades can be considered.

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[60] Hawaiian Electric Submission to the Hawaiʻi Public Utilities Commission, November 18, 2024. Docket No. 2017-0352 – To Institute a Proceeding Relating to a Competitive Bidding Process to Acquire Dispatchable and Renewable Generation Par Hawaiʻi Refining LLC Notice of Withdrawal.

[61] Hawaiian Electric's IGP: 2024 Action Plan Annual Update

[62] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

Puna Generating Station

The Puna Generating Station, located south of Hilo, consists of a combustion turbine (CT3), which is a GE model LM2500, and a steam boiler totaling 35 MW. CT3 is 32 years old and the steam unit is 54 years old. The steam unit is expected to be placed in standby in 2025[63].

This plant is a preferred potential option for natural gas replacement due to the planned decommissioning and proximity to a potential LNG onshore transmission terminal. CT3 could have burners converted to dual fuel; however, additional discussions are required if this is preferred over procuring new turbines. The plant is not in a tsunami evacuation zones according to publicly available GIS data so future upgrades can be considered.

Waimea Generating Station

The Waimea plant consists of three ULSD-fired boilers totaling 7.5 MW that are more than 51 years old located further inland than the other plants. This plant is not preferred for conversion due to the plant proximity and the relatively small capacity.

Maui

Māʻalaea Power Plant

The Māʻalaea Power Plant consists of four combined cycle CTGs (GE LM2500s) that are 17 to 31 years old. These units are capable of combined cycle or simple cycle operation and are currently planned to remain operational through 2045. The total CTG capacity at the Mā’alaea Plant is approximately 80 MW with combined cycle output of about 112 MW.

Units 1 through 9 are diesel generators all over 45 years old, and decommissioning is planned for 2030.[64] Units 10 to 13 are diesel generators which total approximately 50 MW of capacity are planned for retirement in 2027 due to a lack of spare parts with the manufacturer. Additionally, there are two diesel generators that are not scheduled for retirement during the analysis period.

The power plant is currently in the tsunami evacuation zones according to publicly available GIS data meaning new technologies at this plant could run into regulatory and public roadblocks. Therefore, it was not preferred to convert this plant to natural gas.

Kahului Power Plant

The Kahului Power Plant consists of four boilers and steam turbines running on fuel oil. Units 1 through 4 have been scheduled for retirement by 2028 (32 MW), and units 3 and 4 will be converted to synchronous condensers (no power generation or fuel usage) to provide grid stability.[65]

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[63] Hawaiian Electric’s IGP: 2024 Action Plan Annual Update

[64] Hawaiian Electric’s IGP: 2024 Action Plan Annual Update

[65] Hawaiian Electric’s IGP: 2024 Action Plan Annual Update

The power plant is in the tsunami evacuation zones,[66] therefore new technologies at this plant are not feasible.

Scenario Selection for Potential Viable Pathway

The first iteration of the natural gas conversion analysis involved converting or replacing select power plants on Oʻahu, Maui, and Hawaiʻi Island to run on natural gas based on National Renewable Energy Lab (NREL) grid modeling. However, after an initial lifecycle cost analysis was completed by HDR, the results indicated that delivering gas to all of islands would not benefit the ratepayers, so the decision was made to have LNG delivered to the power plants on Oʻahu only.

A scenario with conversion of certain power plants on Oahu was developed including an estimate of LNG volumes needed. The capital and operating expenditures were modeled to develop the preliminary economics for LNG delivery to this island. As this is a preliminary analysis, future evaluations, including technical, environmental, regulatory, and detailed economics, would be needed to determine the configurations of these power plants.

The preliminary lifecycle cost analysis and cost of service analysis determined that maximizing the consumption of natural gas was economically advantageous, so the addition of new power plants in addition to conversions was preferred. HDR assumed that both the decommissioned Barbers Point Power Plant and Kahe Power Plant sites had sufficient space to build a new dual fuel combined cycle power plant. HDR chose the capacity of a new power plant on the Decommissioned Barbers Point Power Plant site by configuring CTG and steam turbine sizes to meet approximately 200 MW, which was close to the capacity of the previous coal power plant located at that site. For additional flexibility to help balance the increasing renewables planned for Oʻahu, a simple cycle CTG peaker plant was added to the former coal plant site in parallel to the combined cycle. This unit would only operate for peak loads and grid support through its fast-ramping capabilities.

HDR chose the new Kahe combined cycle power plant size to match the analysis included in the Kahe Combined Cycle PUC Application (HECO), which was approximately 350 MW[67]. This size aligned with the capacity to replace Kahe boilers 1 through 4 after those units are retired.

HDR developed a two-phase approach for natural gas conversions and new builds to allow for future analysis and design updates based on updated island energy demands, technological advancements, and actual renewable buildouts over the next decade.

All the proposed conversions consider that the power generation equipment will have dual-fuel burners capable of running on gas or oil with gas as the primary fuel and oil used as backup during longer gas outage durations. The new CTG technology will also be capable of operating on high

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[66] *Hawai'i Statewide Energy Projects Directory*. Retrieved from https://energy.hawaii.gov/information-center/project-development-center-tools/hawaii-statewide-energy-projects-directory/

[67] PUC Docket No. 2016-0137: Kahe Combined Generating Unit

percentages of hydrogen to help meet Hawaiʻi's RPS. Many CTG models are currently able to operate on high percentages of hydrogen with paths to 100% hydrogen in the next 5 to 10 years.

Below is the Phase 1 and 2 summaries along with the assumed capacity factors and total electricity generation for each conversion and new plant used in the economics evaluation. HDR used the capacity factors of 0.6 and 0.1 for base-loaded and peaking plants, respectively. A 0.6 capacity factor is slightly higher than historical operations at KPLP of 0.5 (see section on KPLP above), but from the economic analysis performed for this study, higher usage of LNG was preferred, so the capacity factor was increased to 0.6 which is reasonable for a combined cycle power plant.

Table 1. Phase 1 – In Service by 2030

Site	Capacity Factor	Modifications	Capacity	Electricity Generation
KPLP	0.6	Burner replacements with new gas infrastructure (compressor, gas skids, piping)	208 MW	0.6 x 208 MW = 1.1 TWh
Decommissioned Barbers Point Power Plant Site Combined Cycle (CC) and Simple Cycle (SC) Peaker	0.6 (CC) 0.1 (SC)	New 2 x 1 CC power plant with SC peaker - natural gas and fuel oil infrastructure	156 MW CC 60 MW SC	0.6 x 156 MW = 0.82 TWh 0.1 x 60 MW = 0.06 TWh
TOTAL			424 MW	1.98 TWh

Table 2. Phase 2 – In Service by 2035

Site	Capacity Factor	Modifications	Capacity	Electricity Generation
CIP	0.1	New burners on single CTG SC	129 MW	0.1 x 129 MW = 0.1 TWh
Kahe Combined Cycle	0.6	New 3 x 1 CC- natural gas and fuel oil infrastructure	358 MW	0.6 x 358 MW = 1.9 TWh
TOTAL			487 MW	2.0 TWh

Appendix C - Economic Analysis

Summary

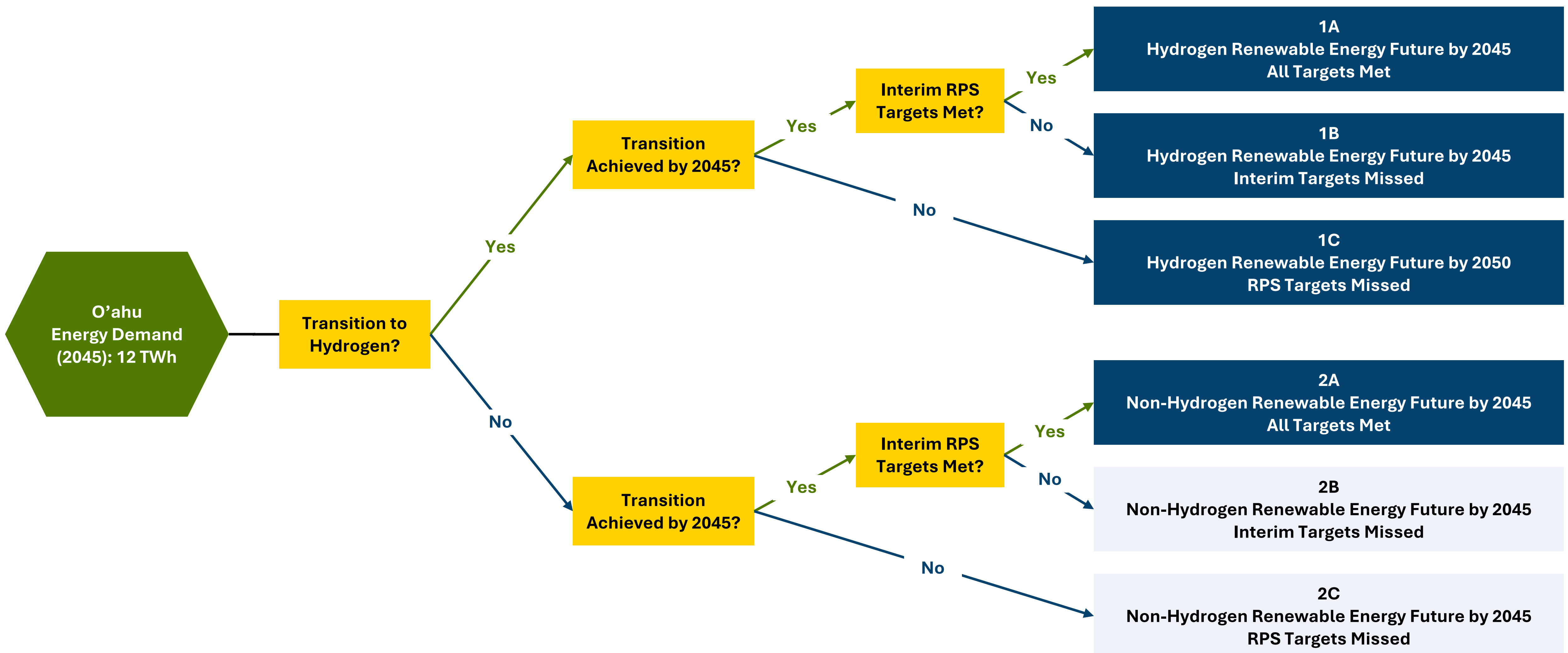
The goal of HDR's economic analysis involved determining the characteristics of a viable pathway that can yield cost savings for ratepayers by implementing a transition to HDR identified and evaluated potential solutions for importing LNG to the island of Oʻahu and implementing natural gas as a bridge fuel for Hawaiʻi's energy initiatives. HDR performed a lifecycle cost analysis to evaluate total costs including upfront capital costs, ongoing operating and maintenance costs, fuel costs, and interim RPS penalties, if applicable, for a base case and a potential build case.

By comparing the lifecycle cost of the base case to a build case, the analysis focuses on the incremental differences specifically attributable to the alternate fuel transition pathway. In cases where the build case results in lower costs than the base case, the results would indicate the cost savings relative to not transitioning to an alternate fuel.

The analysis performed involved an iterative process exploring the potential benefits of introducing LNG infrastructure and determining if the necessary infrastructure to achieve the generation required could be built at a cost less than the cost savings estimated. Based on the initial bookend analysis performed, a key underlying principle was that natural gas would not displace renewable energy. While a renewable energy evaluation was outside HDR's scope of work, the question arose as to whether the projected growth in renewable energy shown in NREL's modeling or Hawaiian Electric's Integrated Grid Plan (IGP), especially by 2030, was achievable. Given the heavy reliance on low sulfur fuel oil (LSFO) in the current grid mix, if there are delays in the construction of renewable energy, or if RPS targets are met just in time, it would be expected that there would be greater use of LSFO than initially projected. In a base case with greater use of LSFO to generate electricity, our analysis can allow for natural gas to displace more LSFO in a build case without impeding the growth of renewables.

HDR's analysis explores several variations in future renewable energy scenarios, each of which incorporates different implicit assumptions that may impact the results of an LNG transition. Under each of the future renewable energy scenarios, we define variations in the defined base case, which impacts how natural gas generation is assumed to operate. As shown in the diagram below, we evaluated two distinct alternative futures, with three sub-alternatives each that lead to a total of six potential solutions.

Figure 1: Future Possibilities Considered



Not depicted – Alternative 3: Alternative 3A generally follows Alternative 1A and Alternative 3B follows 1A. Alternative 3 updates the fuel mix displaced.

Description of Base Case

Across all evaluated alternatives, there are several key consistent assumptions used in the analysis:

- Estimated future energy demand on Oʻahu is 12.4 TWh by 2045[68], and the energy demand is interpolated to estimate demand in the interim years;
- Energy mix not attributed to LSFO is assumed to be generated by renewable sources;
- Weighted average heat rates based on current values, and where applicable, specifications assumed for newly constructed or converted plants, were used to convert fuel cost forecasts to a cost per MWh; and
- Fuel projections were based on forecasts provided by Facts Global Energy (FGE).

Possibilities included under Alternative 1 assume a transition to hydrogen as a firm source of renewable energy. Without any interim LNG infrastructure, significant capital costs to transition to hydrogen, including pipelines, plant conversions, and transmission upgrades, are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets).

Possibilities included in Alternative 2 assume a transition to an undefined non-hydrogen renewable fuel source. Significant capital costs to transition to this undefined renewable fuel source are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets).

Description of Build Case

Across all evaluated alternatives, there are several key consistent assumptions used in the analysis:

- Estimated future energy demand on Oʻahu is 12.4 TWh by 2045, and the energy demand is interpolated to estimate demand in the interim years;
- LNG infrastructure is introduced only on Oʻahu and only offsets generation from LSFO unless otherwise stated (e.g. Alternative 3);
- Weighted average heat rates based on current values, and where applicable, specifications assumed for newly constructed or converted plants, were used to convert fuel cost forecasts to a cost per MWh;
- Fuel projections were based on forecasts provided by FGE; and
- Significant portions of LNG infrastructure can be re-used for hydrogen applications, minimizing stranded assets and preparing Hawaiʻi for a conversion to 100 percent renewable energy for 2045.

[68] Based on Hawaiian Electric Pathways Conservative Load Forecast.

All scenarios rely on a consistent staggered deployment of LNG infrastructure contained in the LNG Import Study Technical Documentation. By 2030, 424 MW of capacity of natural gas is installed that can generate up to 2 TWh of electricity. By 2035, an additional 487 MW of capacity has been converted to natural gas, which can be used to generate another 2 TWh of electricity. It is assumed that LNG remains economically viable to be dispatched for a maximum of 4 TWh, unless constrained by RPS targets.

Possibilities included under Alternative 1 assumes a transition to hydrogen as a firm source of renewable energy. With a future transition to hydrogen, significant portions of the initial capital investment in LNG infrastructure can be re-used for hydrogen when it becomes part of the energy mix. The capital costs incurred in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets) are minimal relative to the base case.

Possibilities included in Alternative 2 explore a transition to an undefined non-hydrogen renewable fuel source, which does not allow for the re-use of LNG infrastructure. Significant capital costs to transition to this undefined renewable fuel source are primarily spent in the 5 years leading up to the transition to a fully renewable electric grid (2040-2045 based on RPS targets), identical to the base case.

Overview of Evaluated Alternatives

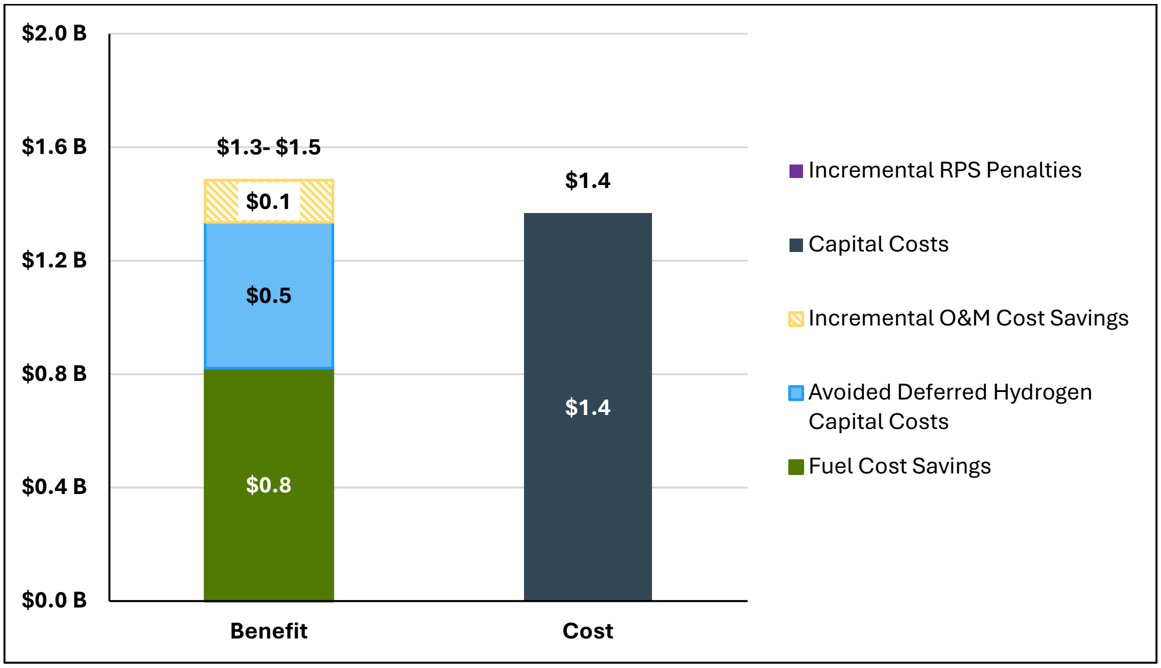
Alternative 1A: Transition to Hydrogen by 2045, All RPS Targets Met

In Alternative 1A, it is assumed that by 2045, Oʻahu has met all interim RPS targets and is utilizing hydrogen as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2040, LSFO generation is curtailed below 4 TWh due to increasingly stringent RPS targets, before being phased out in 2045.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2040, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2040, LNG is curtailed to comply with RPS standards, before being phased out in 2045. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2040 and 2045 are significantly reduced.

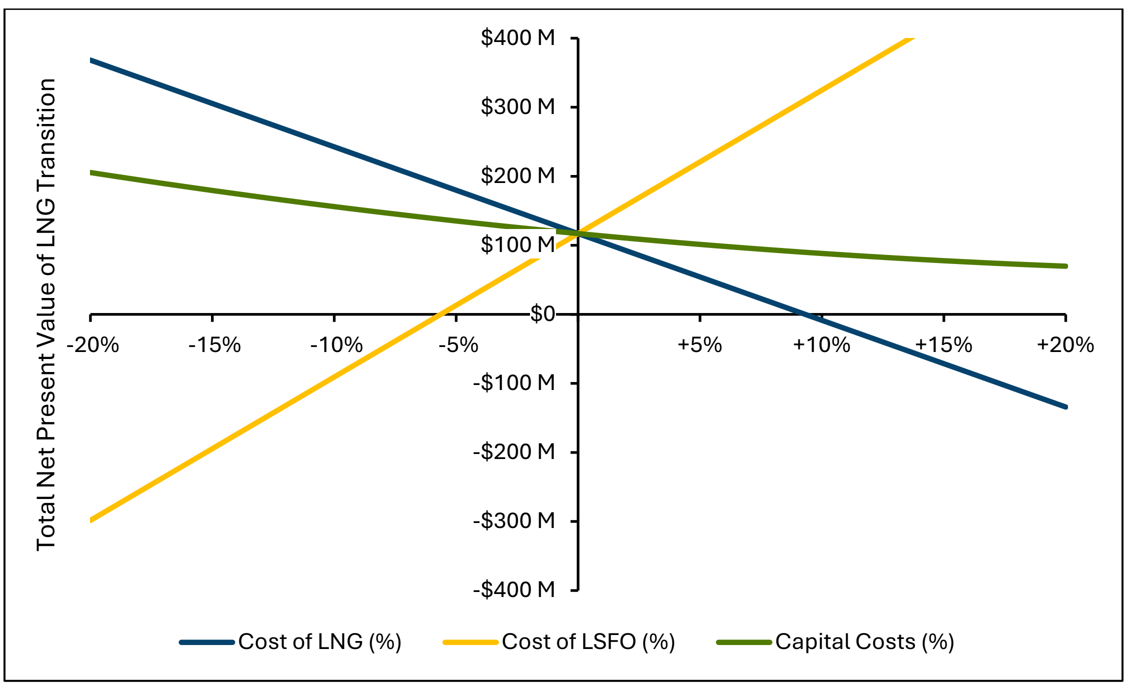
The benefits of an interim transition to natural gas exceed the costs, with a net present value of about $150 million, as shown in Figure 2. The levelized cost savings from an LNG transition are $10.2/MWh, which equates to residential energy cost savings of about 2.6 percent (approximately $61 in savings per year). With the most stringent version of Alternative 1, an LNG transition is shown to generate benefits more than its costs, which can provide cost savings to ratepayers, relative to a base case where no LNG infrastructure is constructed.

Figure 2: Net Present Value of LNG Transition Under Alternative 1A



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 10%, LSFO prices do not decrease by more than 5%, or capital costs do not increase by more than 20%. As can be seen in Figure 3, there is potential to see cost savings well more than the initial $150 million.

Figure 3: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1A



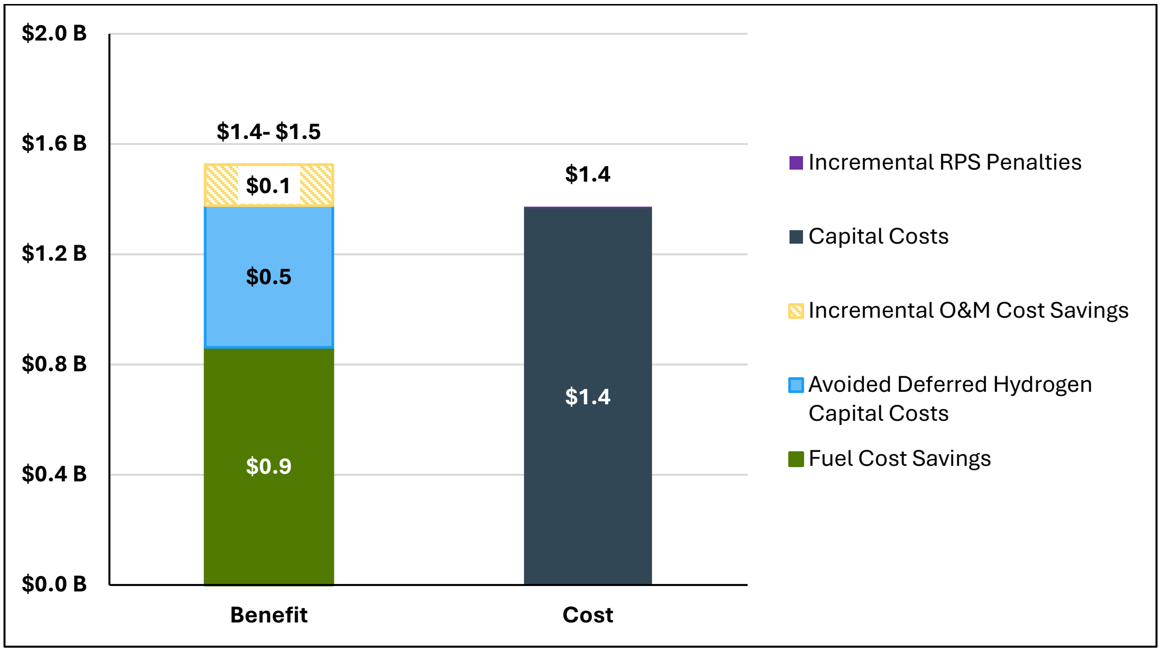
Alternative 1B: Transition to Hydrogen by 2045, Some RPS Targets Met

In Alternative 1B, it is assumed that by 2045, Oʻahu has met most interim RPS targets and is utilizing hydrogen as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2040, LSFO generation continues to account for 4 TWh due to either the delayed implementation of renewable generation, maintaining grid stability, or minimizing costs to ratepayers before being phased out in 2045. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2045, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2045, LNG is phased out in place of hydrogen. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2040 and 2045 are significantly reduced.

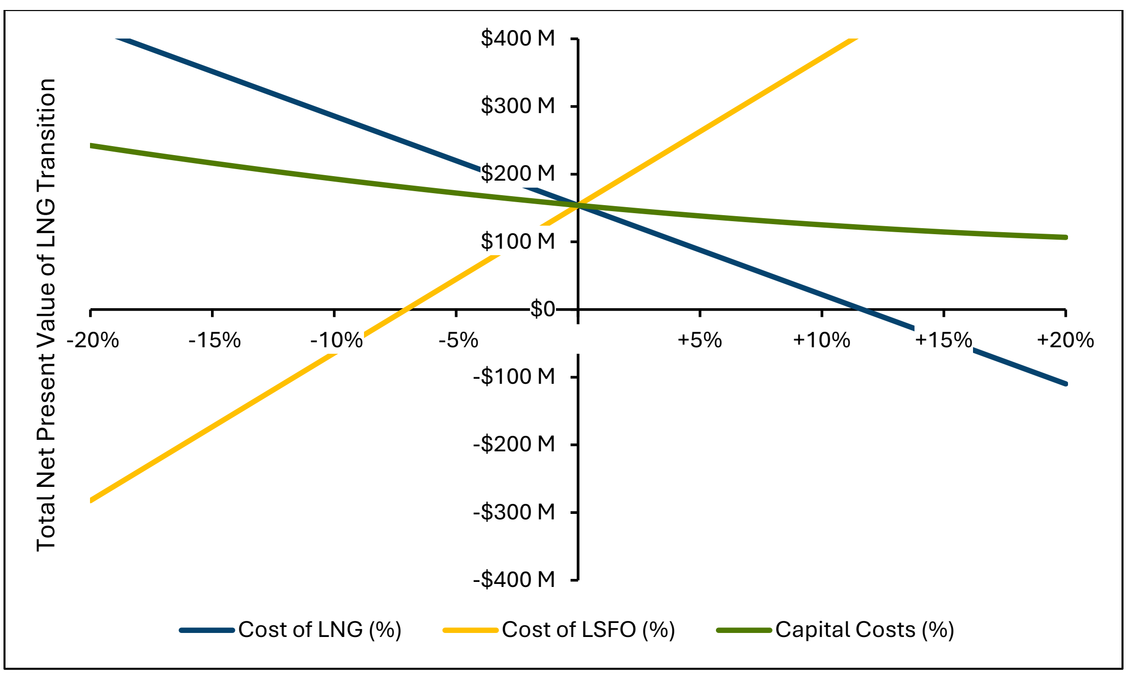
The additional fuel cost savings from increased non-renewable generation between 2040 and 2045 result in the net present value increasing to about $187 million, as shown in Figure 4. The levelized cost savings from an LNG transition are $12.2/MWh, which equates to residential energy cost savings of about 3.2 percent (approximately $73 in savings per year). If more non-renewable generation is required than allowed for under the RPS targets, a transition to natural gas generation will save ratepayers more than if LFSO were consumed instead.

Figure 4: Net Present Value of LNG Transition Under Alternative 1B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 12%, LSFO prices do not decrease by more than 7%, or capital costs do not increase by more than well over 20%. As can be seen in Figure 5, there is potential to see cost savings well over the initial $187 million.

Figure 5: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1B



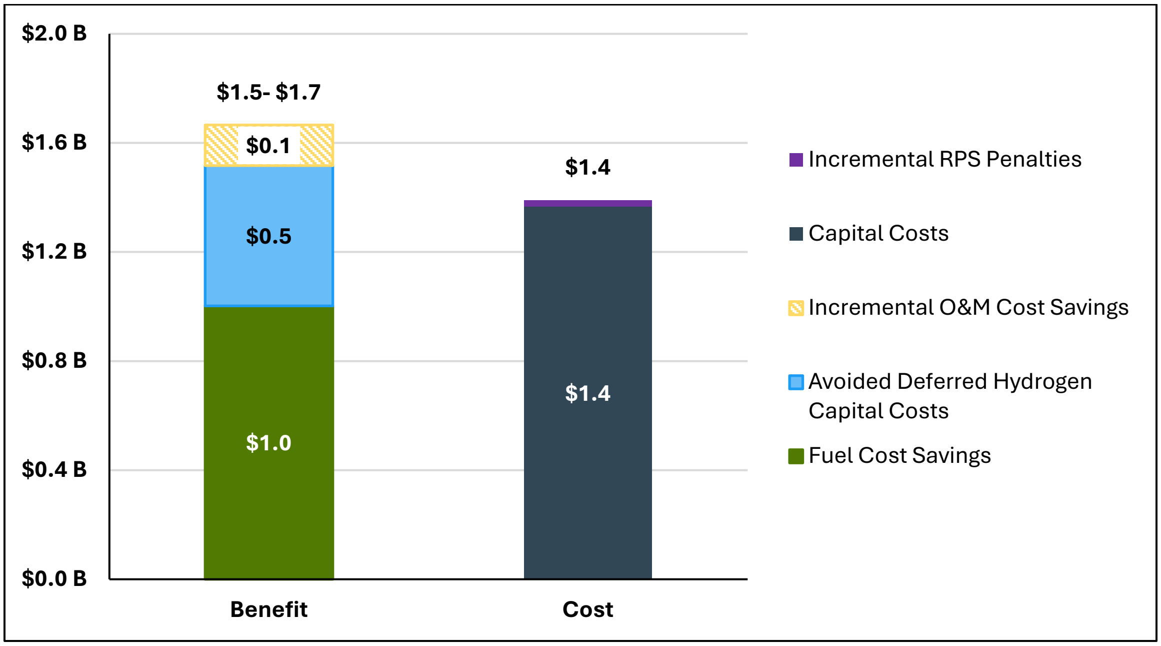
Alternative 1C: Transition to Hydrogen by 2050

In Alternative 1C, it is assumed that the transition to a 100% renewable electric grid has been delayed by 5 years. While interim RPS targets beyond 2040 are assumed to not be met, by 2050, hydrogen is utilized as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2045 and 2050 to build necessary upgrades including pipelines, transmission lines, and plant conversions to prepare for the implementation of hydrogen. Beyond 2046, LSFO generation steps down to 2 TWh to account for the first phase of hydrogen generation being deployed, before being fully phased out in 2050. It is acknowledged that this scenario results in the RPS target in 2040 and 2045 not being met, and penalties are calculated accordingly. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2046, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2046, LNG is curtailed to 2 TWh to account for the first phase of hydrogen generation, before phased out entirely by 2050. Due to the initial investment in natural gas infrastructure that can be re-used, capital costs to prepare for hydrogen between 2045 and 2050 are significantly reduced.

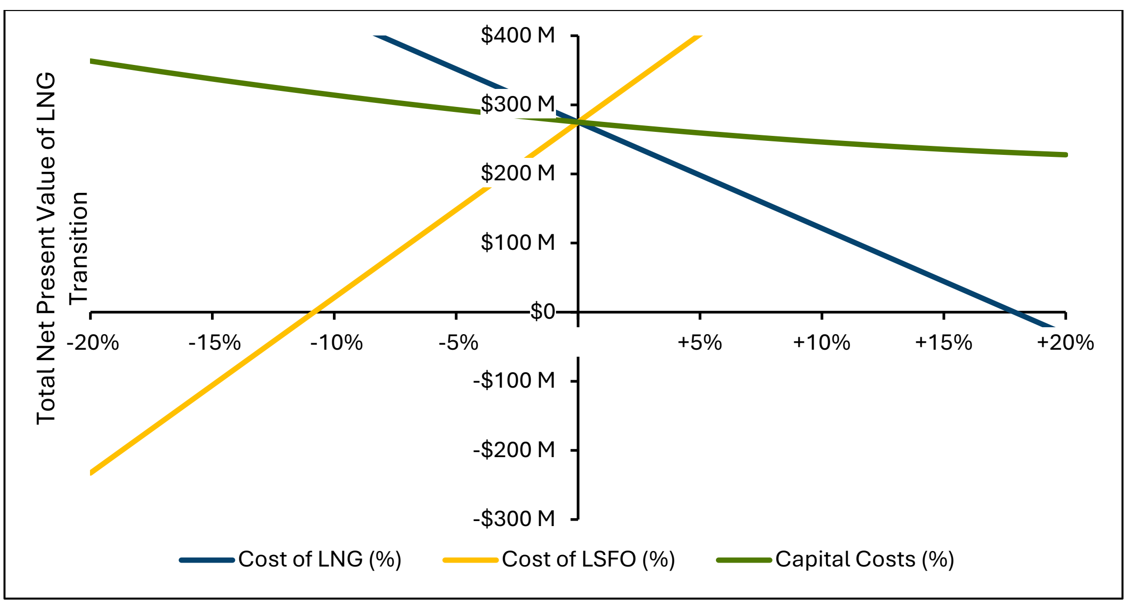
The additional fuel cost savings from increased non-renewable generation between 2040 and 2049 result in the net present value increasing to about $308 million (Figure 6). The levelized cost savings from an LNG transition are $17.8/MWh, which equates to residential energy cost savings of about 4.6 percent (approximately $107 in savings per year). If the implementation of a fully renewable energy grid is delayed, a transition to natural gas generation will save ratepayers more than if LFSO were burned instead.

Figure 6: Net Present Value of LNG Transition Under Alternative 1C



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices do not increase by more than 18%, LSFO prices do not decrease by more than 11%, or capital costs do not increase by more than well over 20%. As can be seen in Figure 7, there is potential to see cost savings well over the initial $308 million.

Figure 7: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 1C



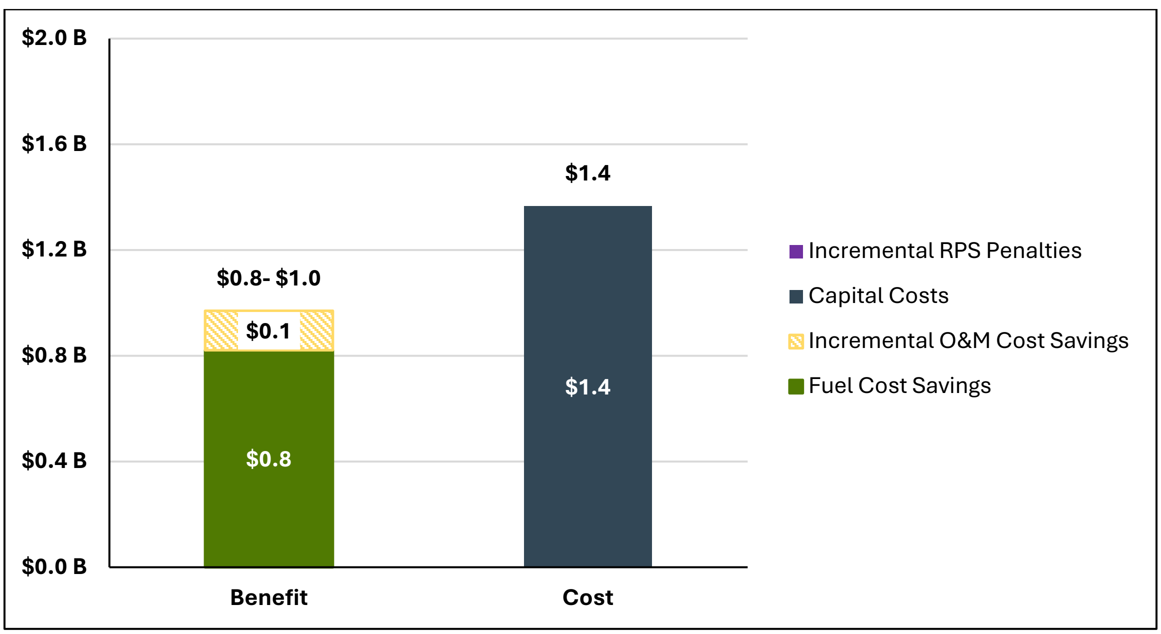
Alternative 2A: Transition to Non-Hydrogen Fuel by 2045, All RPS Targets Met

In Alternative 2A, it is assumed that by 2045, Oʻahu has met all interim RPS targets and is utilizing an undefined renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, capital costs are spent primarily between 2040 and 2045 to build necessary upgrades to prepare for the implementation of a new renewable fuel. Beyond 2040, LSFO generation is curtailed below 4 TWh due to increasingly stringent RPS targets, before being phased out in 2045.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2040, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2040, LNG is curtailed to comply with RPS standards, before being phased out in 2045. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2040 and 2045.

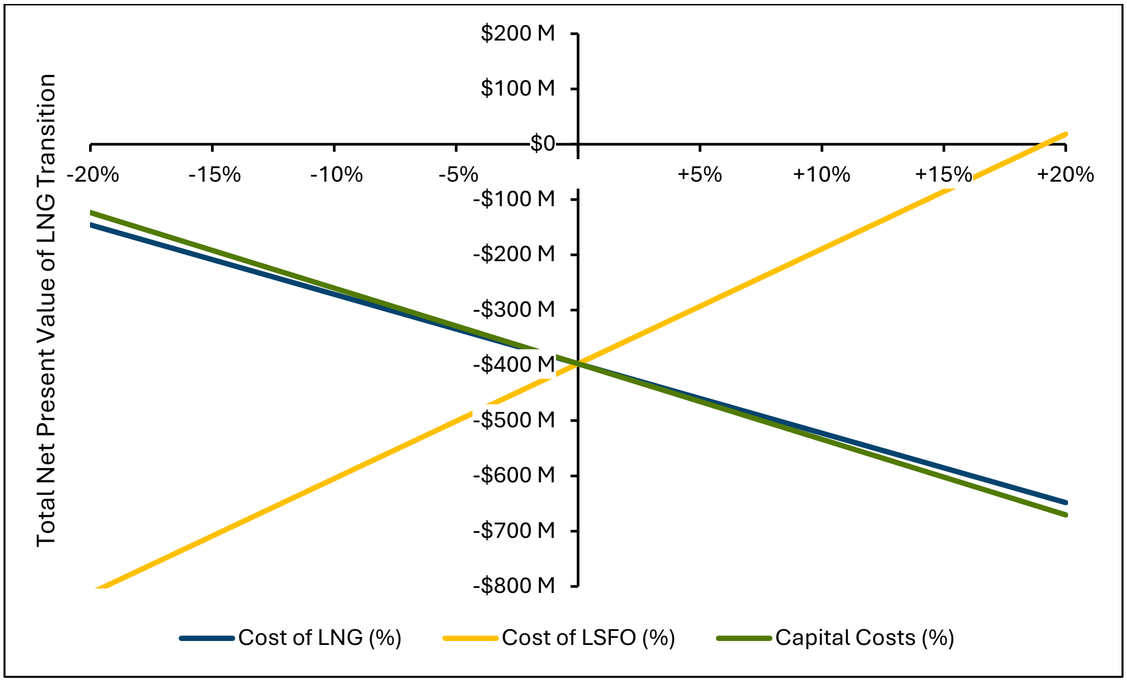
Without the benefit of re-using the LNG infrastructure, the benefits of an interim transition to natural gas do not exceed the costs, with a net present value of about -$364 million (Figure 8). The levelized cost increase from an LNG transition is $24.6/MWh, which equates to a residential energy cost increase of about 6.4 percent (approximately $148 in additional electricity costs per year). With the most stringent version of Alternative 2, an LNG transition is shown to generate costs above its benefits, which can result in negative impacts to ratepayers, relative to a base case where no LNG infrastructure is constructed.

Figure 8: Net Present Value of LNG Transition Under Alternative 2A



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. Significant changes to the base assumptions would be required in order for an LNG transition to generate cost savings without re-using the infrastructure for future renewable energy needs, as can be seen in Figure 9.

Figure 9: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2A



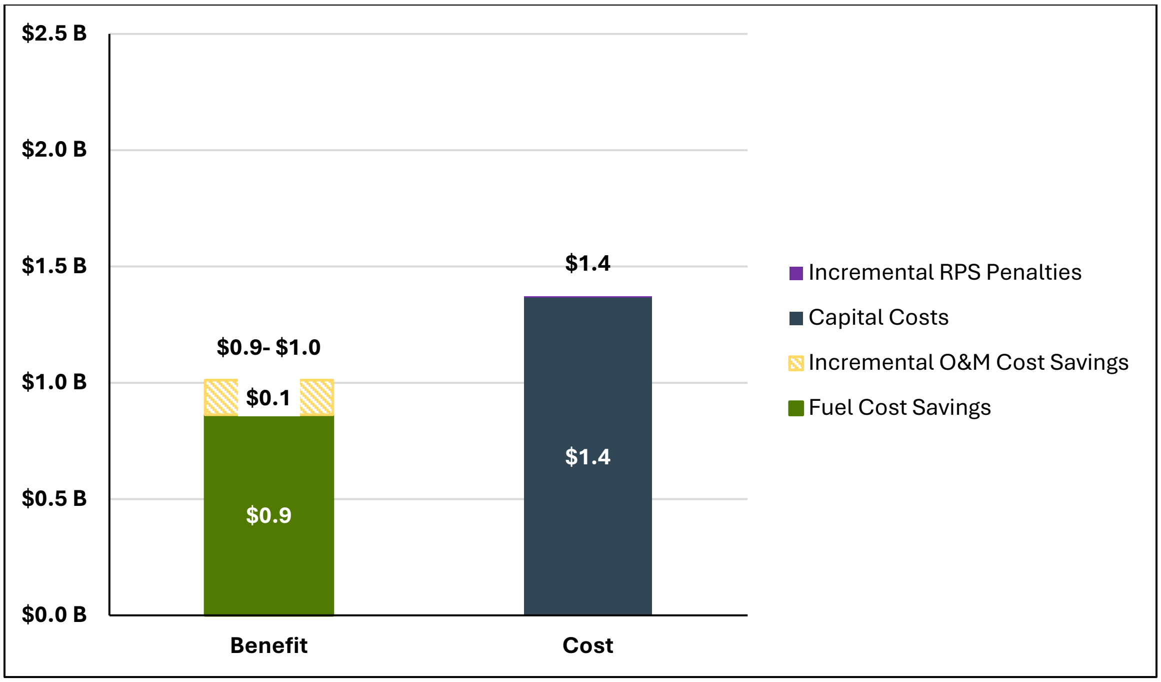
Alternative 2B: Transition to Non-Hydrogen by 2045, Some RPS Targets Met

In Alternative 2B, it is assumed that by 2045, Oʻahu has met most interim RPS targets and is utilizing an undefined renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2040 and 2045 to prepare for the implementation of a new renewable fuel. Beyond 2040, LSFO generation continues to account for 4 TWh due to either the delayed implementation of renewable generation, assisting to maintain grid stability, to minimize costs to ratepayers before being phased out in 2045. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2045, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2045, LNG is phased out in place of an undefined renewable firm fuel source. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2040 and 2045.

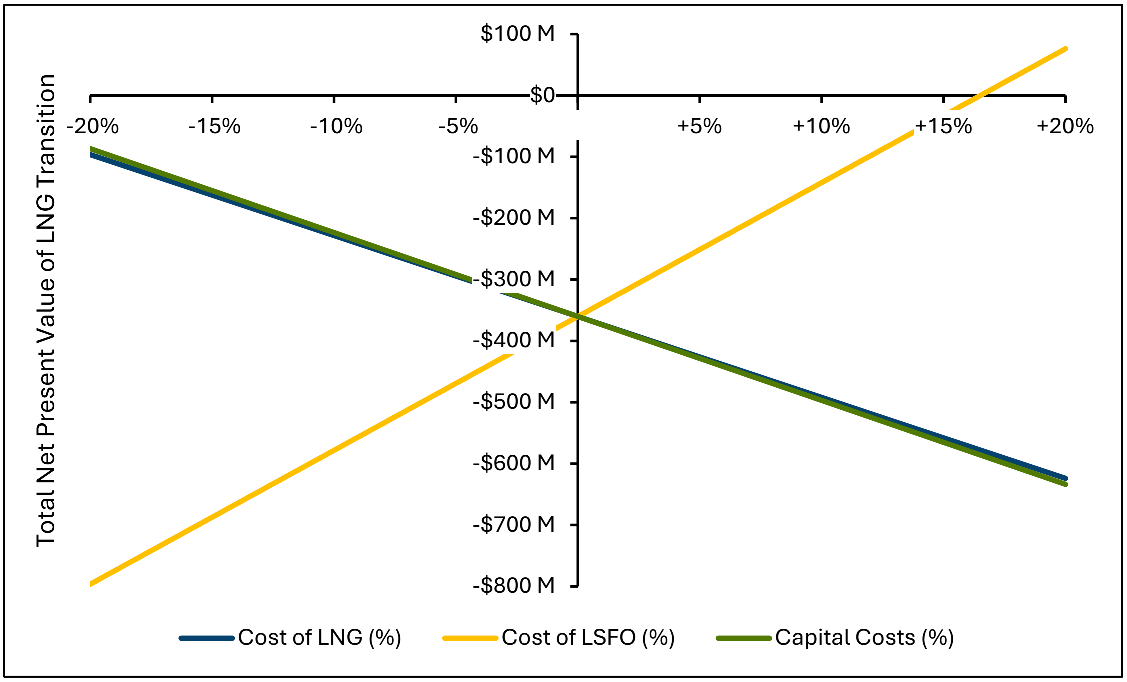
The additional fuel cost savings from increased non-renewable generation between 2040 and 2045 result in the net present value increasing, though still falling approximately $327 million short of covering the infrastructure costs, as shown in Figure 10. The levelized cost increase from an LNG transition is $21.2/MWh, which equates to an estimated residential energy cost increase of about 5.5 percent (approximately $127 in additional electricity costs per year).

Figure 10: Net Present Value of LNG Transition Under Alternative 2B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices or capital costs decrease by more than 20%, or LSFO prices increase by more than 17%. There are significant hurdles to show a transition being cost-effective if the LNG infrastructure cannot be re-used as part of a fully renewable energy solution (Figure 11).

Figure 11: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2B



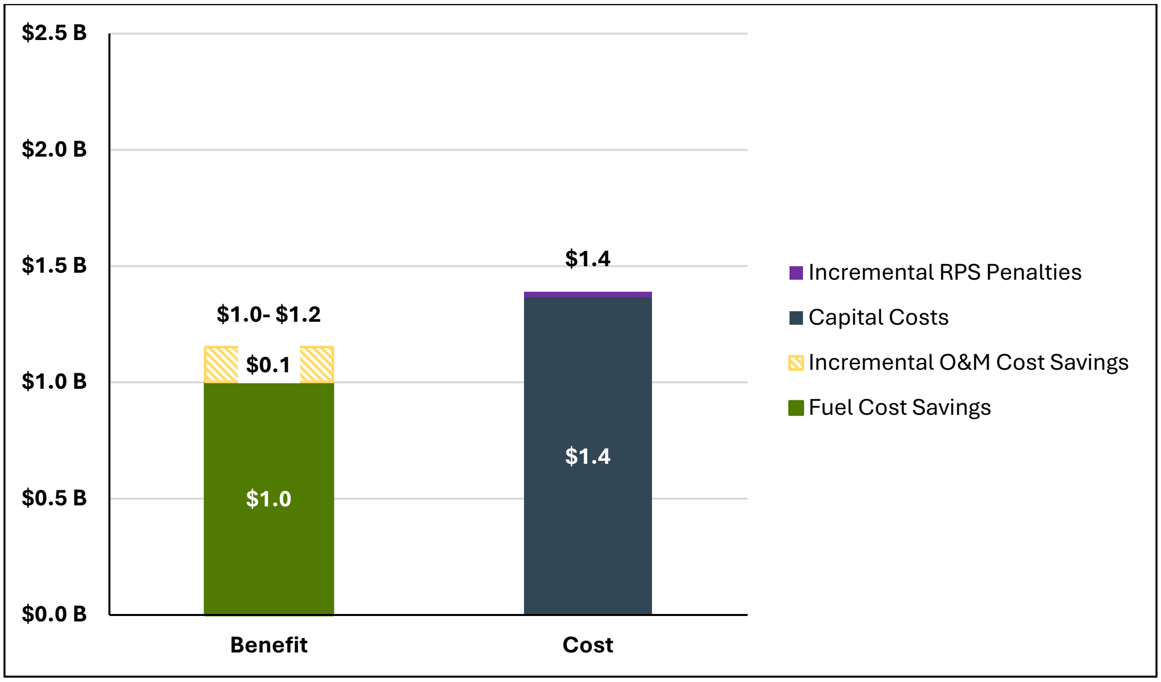
Alternative 2C: Transition to Non-Hydrogen by 2050

In Alternative 2C, it is assumed that the transition to a 100% renewable electric grid has been delayed by 5 years. While interim RPS targets beyond 2040 are assumed to not be met, by 2050, an undefined firm fuel source is utilized as a renewable firm fuel source to meet the mandated 100% renewable energy transition. In the base case, without any interim LNG infrastructure, capital costs are spent primarily between 2045 and 2050 to prepare for the implementation of a new renewable fuel. Beyond 2046, LSFO generation steps down to 2 TWh to account for the first phase of a non-hydrogen renewable fuel generation being deployed, before LSFO is fully phased out in 2050. It is acknowledged that this scenario results in the RPS target in 2040 not being met, and penalties are calculated. While the penalties would apply to both the base case and the build case, we conservatively show the penalties only applied to the build case.

In the build case, LNG infrastructure is constructed in two phases, with the first phase operational by 2030, providing 2 TWh of natural gas generation. The second phase is assumed to be completed by 2035, providing another 2 TWh of natural gas generation. Between 2035 and 2046, the full 4 TWh of natural gas generation is used to offset LSFO generation. Beyond 2046, LNG is curtailed to 2 TWh to account for the first phase of an undefined renewable firm fuel source. Assuming the renewable fuel is unable to re-use the natural gas infrastructure, the initial investment in natural gas infrastructure will not significantly reduce the capital costs to prepare for the renewable fuel between 2045 and 2050.

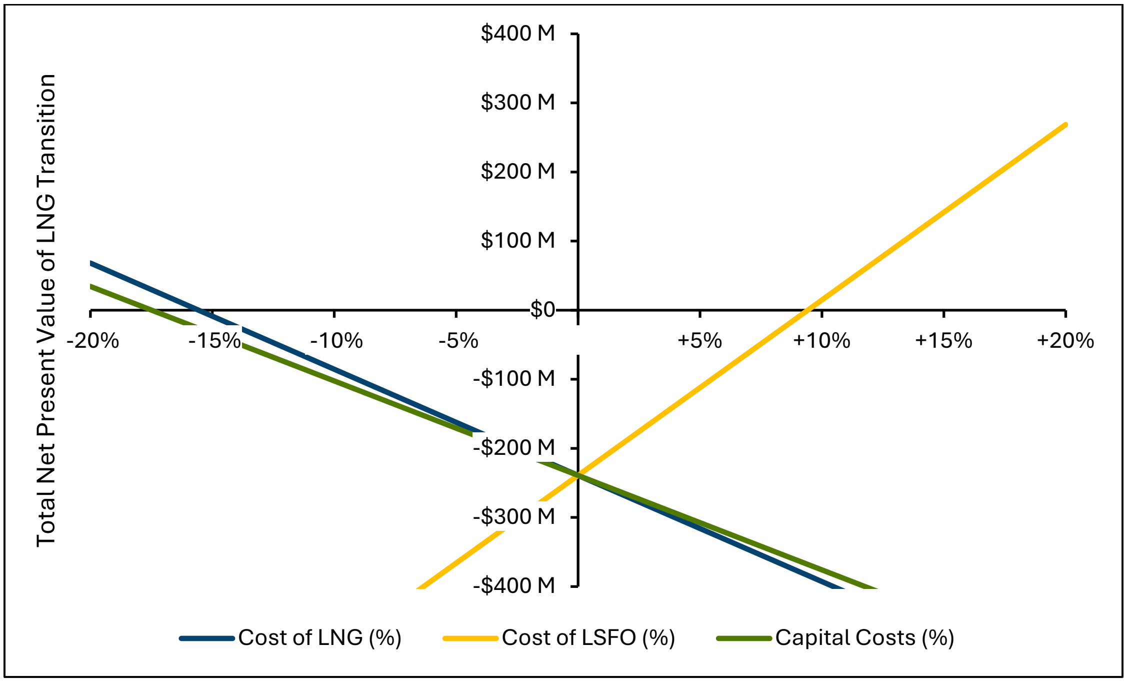
The additional fuel cost savings from increased non-renewable generation between 2040 and 2049 result in the net present value increasing, though still falling approximately $206 million short of covering the infrastructure costs, as shown in Figure 12. The levelized cost increase from an LNG transition is $11.9/MWh, which equates to a residential energy cost increase of about 3.1 percent (approximately $71 in additional electricity costs per year).

Figure 12: Net Present Value of LNG Transition Under Alternative 2C



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if LNG prices decrease by more than 16%, capital costs decrease by more than 17%, or LSFO prices increase by more than 9%. Delays in implementing a fully renewable electric grid still is not enough to make LNG infrastructure cost-effective if the infrastructure cannot be re-used as part of a fully renewable energy solution (Figure 13).

Figure 13: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 2C



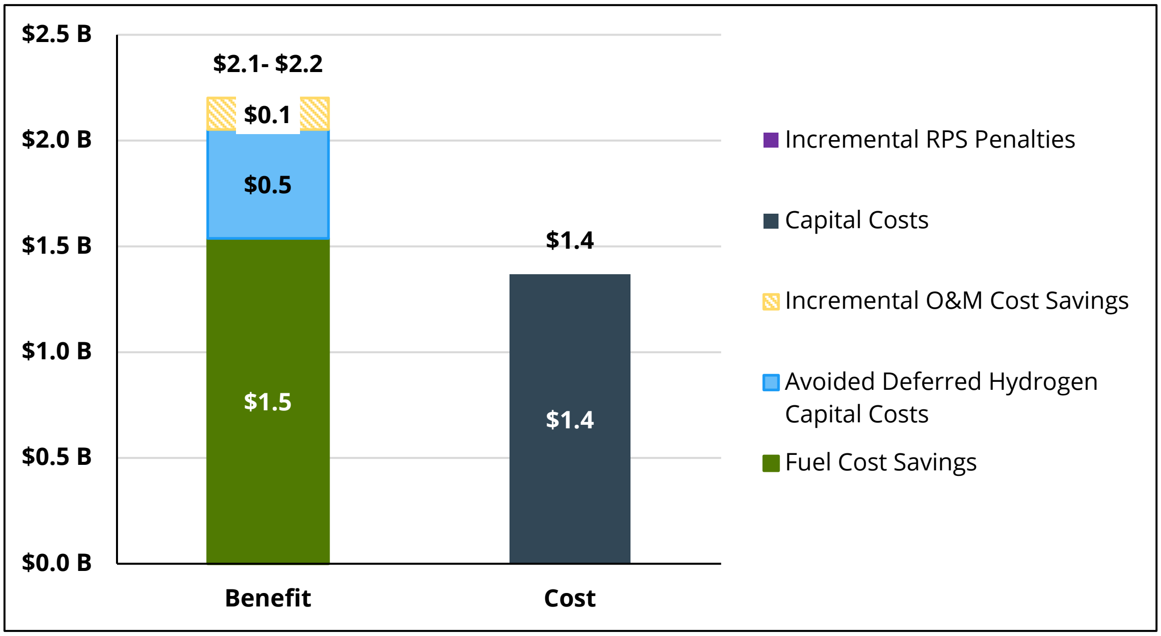
Alternative 3A: Transition to Hydrogen Fuel by 2045, All RPS Targets Met, Adjusted Displaced Fuels

In Alternative 3A, a more optimistic future scenario where a transition to hydrogen results in the re-use of LNG infrastructure, similar to Alternative 1A is explored. Unlike Alternative 1A, where LNG displaces LSFO, PLEXOS energy modeling runs with and without LNG. The data indicated that with the introduction of LNG, the major fuels displaced included a mix of LSFO, utility-scale solar, and biodiesel. The weighted average fuel costs of this mix are substantially higher than the average fuel costs of just LSFO, resulting in significantly higher fuel cost savings when measuring against a transition to LNG. Additionally, there would likely be some avoided generation capacity costs as some of these newly constructed solar arrays or biodiesel plants could be avoided altogether, though this has been excluded from HDR's analysis.

Assuming in this solution that the RPS targets are met, LNG is fully phased out by 2045, and significant portions of LNG infrastructure are repurposed for hydrogen, this adjustment to the energy mix offset by LNG significantly increases the fuel cost savings, and when combined with avoided deferred hydrogen capital costs, approximately doubling the benefit.

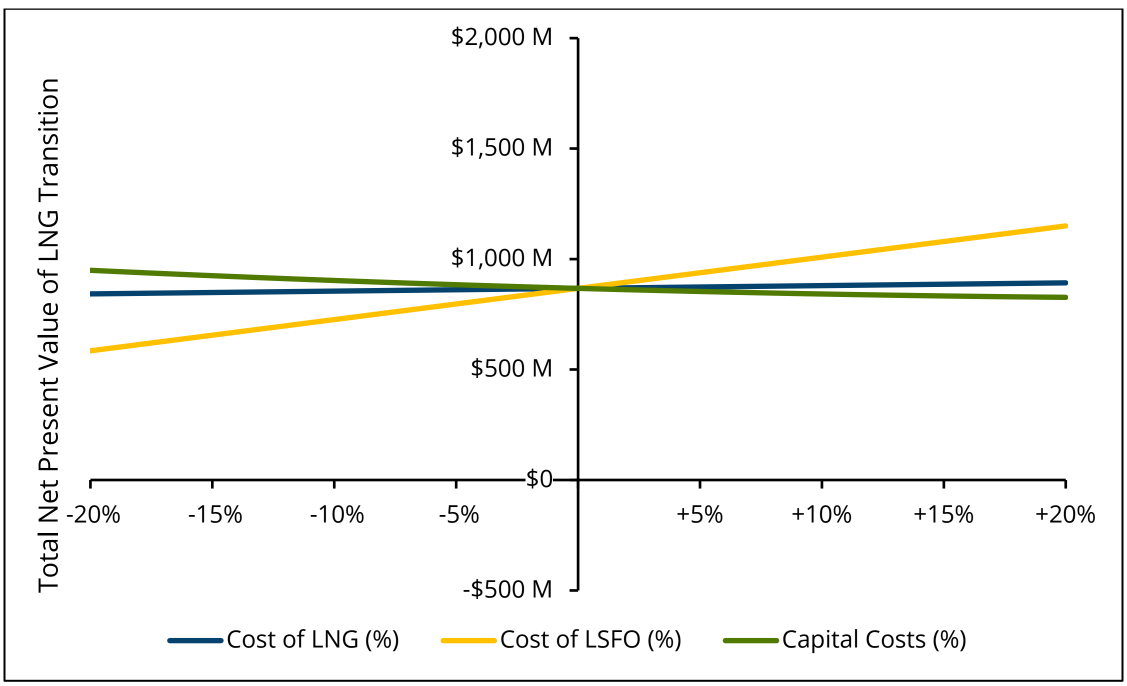
With the adjusted fuel mix displaced by natural gas, the benefits of an interim transition to natural gas exceed the costs, with a net present value of about $867 million. The levelized cost savings from an LNG transition are $59/MWh, which equates to residential energy cost savings of about 15.2 percent (approximately $352 in cost savings per year) (Figure 14).

Figure 14 Net Present Value of LNG Transition Under Alternative 3A



Under a sensitivity analysis conducted, there is potential to see cost savings more than the initial $867 million. With relaxing the RPS standards or assuming a potential 5-year delay in the transition to renewable energy (mirroring Alternatives 1B or 1C), the benefits of transitioning would be even greater than the results shown, and greater savings could be passed on to ratepayers (Figure 15).

Figure 15 Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3A



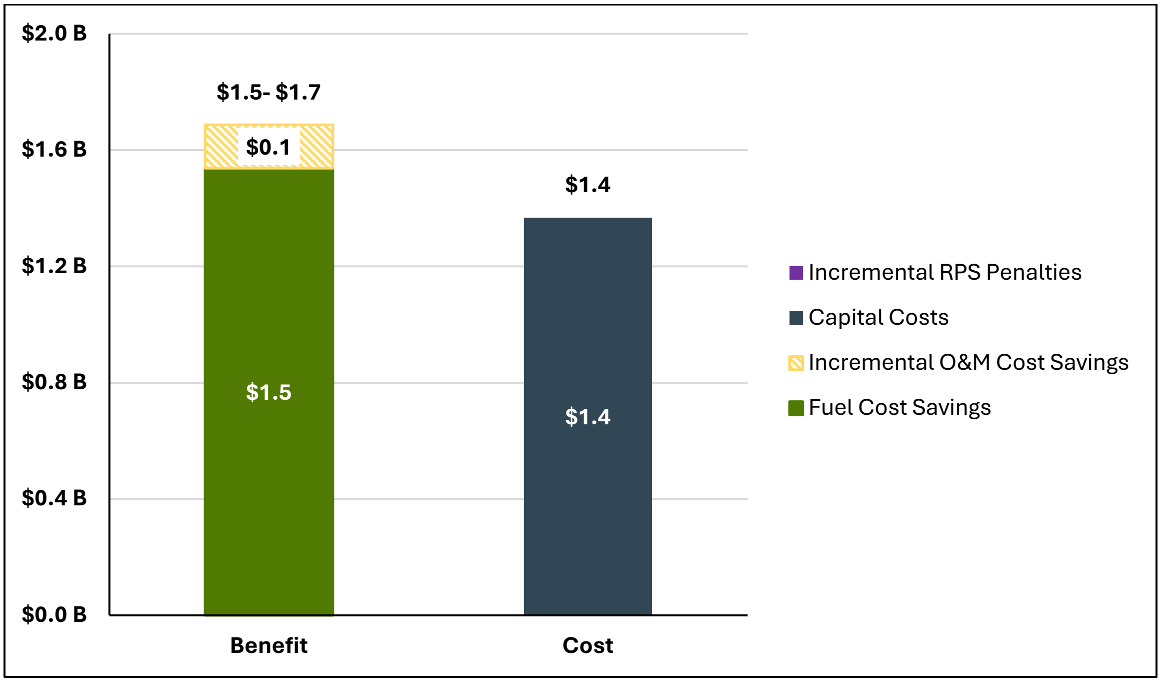
Alternative 3B: Transition to Non-Hydrogen Fuel by 2045, All RPS Targets Met, Adjusted Displaced Fuels

Alternative 2 established the need for infrastructure to be re-used to generate benefits for ratepayers because the fuel savings and operational efficiencies from displacing LSFO are not enough to cover the capital costs for the necessary LNG infrastructure. However, in Alternative 3A, we take Alternative 2A and make one key change to explore the impacts if the fuel mix displaced changes. Instead of assuming LNG displaces LSFO, we rely on PLEXOS energy modeling runs with and without LNG. The data indicated that with the introduction of LNG, the major fuels displaced included a mix of LSFO, utility-scale solar, and biodiesel. The weighted average fuel costs of this mix is substantially higher than the average fuel costs of just LSFO, resulting in significantly higher fuel cost savings when measuring against a transition to LNG. Additionally, there would likely be some avoided generation capacity costs as some of these newly constructed solar arrays or biodiesel plants could be avoided altogether, though this has been excluded from HDR's analysis.

Assuming in this solution that the RPS targets are met, LNG is fully phased out by 2045, and significant portions of LNG infrastructure cannot be repurposed for a non-hydrogen fuel, this adjustment to the energy mix offset by LNG still significantly increases the fuel cost savings, approximately doubling the benefit, and indicating a positive net present value, unlike Alternative 2A.

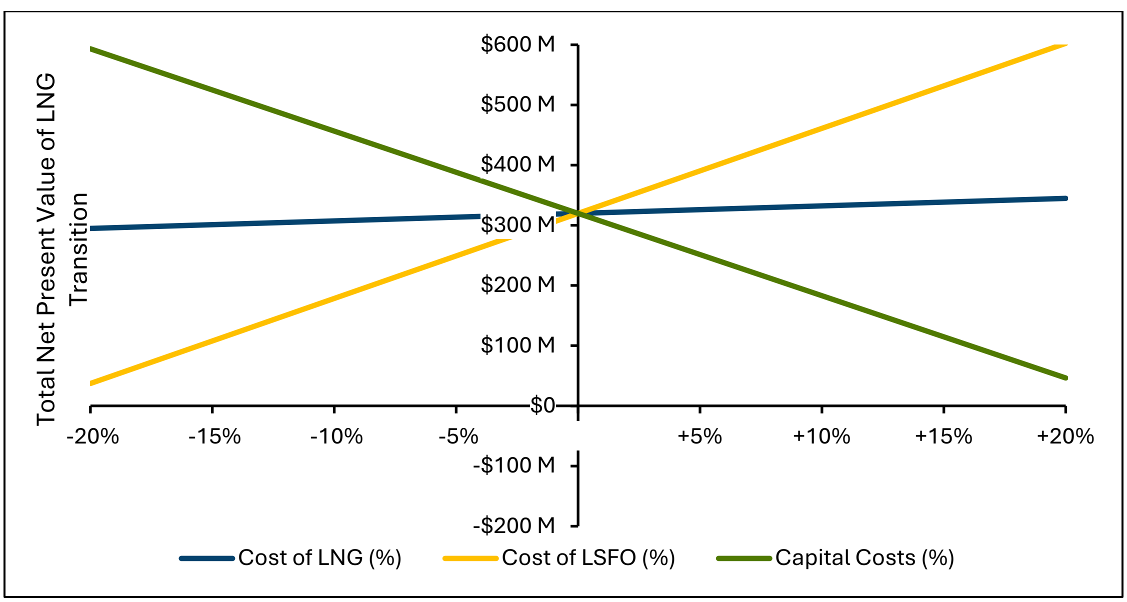
With the adjusted fuel mix displaced by natural gas, the benefits of an interim transition to natural gas exceed the costs, with a net present value of about $353 million (Figure 16). The levelized cost savings from an LNG transition are $23.9/MWh, which equates to residential energy cost savings of about 6.2 percent (approximately $143 in cost savings per year). If displacing more expensive fuels than LSFO, even without the re-use of LNG infrastructure as part of a future firm renewable generation source, the transition cost can yield cost savings to ratepayers.

Figure 16: Net Present Value of LNG Transition Under Alternative 3B



Under a sensitivity analysis conducted, results are most sensitive to a change in LSFO prices. An LNG transition can generate cost savings if variables do not change more than 20% from the initial base values (Figure 17), there is potential to see cost savings well above the initial $353 million. By relaxing the RPS standards or assuming a potential 5-year delay in the transition to renewable energy (mirroring Alternatives 2B or 2C), the benefits of transitioning would be even greater than the results shown, and greater savings could be passed on to ratepayers.

Figure 17: Sensitivity Analysis of Net Present Value of LNG Transition, Alternative 3B



Economic Analysis - Conclusions

From the scenarios evaluated, key conclusions can be drawn. Viable pathways exist that allow for the staggered implementation of LNG that can result in cost savings to ratepayers while still adhering to RPS targets. Planned re-use of constructed infrastructure will both maximize cost savings and help prepare for a final transition to a fully renewable firm fuel. Another important consideration is the fuel that natural gas is assumed to be displacing. While displacing LSFO will reduce reliance on one volatile fuel source, some other renewable fuels, like biodiesel, are projected to be more costly than LSFO. The fuel mix displaced by natural gas drives cost savings, and as seen between Alternative 1A and 3A, can yield significant differences in cost savings. With the planned re-use of LNG infrastructure for a hydrogen transition in 2045, the incremental levelized cost of energy will be reduced by between 2.1 percent (Alternative 1A) and 14.6 percent (Alternative 3) under the baseline assumptions.

LNG can also act as a potential hedge to mitigate risk. In the event of increased reliance on firm generation, or if the transition to a fully renewable grid takes longer than expected, natural gas yields greater benefits to ratepayers while also reducing emissions prior to getting to a fully renewable grid. The new infrastructure built would offer network resiliency and increased generation capacity, along with reduced volatility of fuel prices, which are important benefits of an LNG transition to consider that are not monetized in the economic analysis itself.

Appendix D - LNG Import Evaluation

Summary

Included in this Technical Documentation is an overview of relevant LNG storage, transportation, and regasification technologies, which provides necessary background for this study. Additionally, HDR incorporated a summary of the engineering analysis that took place during this project to provide context into key decisions. This Technical Documentation culminates with a description of the proposed solution including LNG infrastructure, demand requirements, potential sourcing options, capital expenses, and other details relevant to establishing LNG as a fuel source on Oʻahu.

HDR identified and evaluated potential solutions for importing LNG to the island of Oʻahu and implementing natural gas as a bridge fuel for Hawaiʻi's energy initiatives. We assessed the technical feasibility of various LNG supply chain options and developed a phased approach for implementing LNG and natural gas infrastructure that can reduce emissions when compared to Oʻahu's current energy ecosystem and initiate Hawaiʻi's path to meeting its net-zero goal in 2045.

At a high level, the solution proposes a floating storage and regasification unit (FSRU) moored off Barbers Point, Oʻahu; a subsea pipeline connecting the FSRU and Oʻahu and developing and converting new and existing power generation facilities to consume natural gas. HDR split the approach into two phases to provide a grace period between specific development milestones. This added flexibility allows Hawaiʻi to adapt in the future and confirm renewable portfolio standard (RPS) targets are met based on shifts in energy demand, technological advancements, and performance of intermittent fuel sources compared to today's projections. Additionally, this approach nearly eliminates stranded assets without compromising consumer energy costs, grid reliability, or resiliency. Table 1 below summarizes the proposed LNG approach.

Table 1. Phase Approach Summary

Title	Construction Period	Key LNG Infrastructure
Phase 1	2027 to 2030	FSRU and Buoy System Subsea Pipeline Onshore Pipeline to Barbers Point Combined Cycle and Kalaeloa Partners LP (KPLP) Locations
Phase 2	2031 to 2035	Onshore Pipeline to Kahe Power Plant (Kahe) and Campbell Industrial Park (CIP) Locations

Summary of LNG Infrastructure

Subsea Pipeline

- A pipeline that is laid on the seabed or below it inside a trench.

- FSRU comes equipped with Submerged Turret Loading (or similar technology) for gas transfer to a subsea pipeline.

International Organization for Standardization (ISO) Containers

- Vacuum-insulated, cryogenic tanks encased in a standard, container-type box frame and approved for truck transport and shipping by container vessel.
- Shipped like cargo from the mainland and transported from the port to an onshore storage location via trucks.
- ISO containers typically hold up to 10,000 gallons of LNG.

Onshore Storage Vessels

- Storage tank engineered to keep LNG below its vaporization temperature.
- Storage volumes and configurations can vary widely depending on need.

Overview of LNG Technologies

FSRU

An FSRU has the capacity to act similarly to a land-based terminal with the added benefit of minimizing the footprint on land. These units can receive, store, and vaporize LNG and distribute natural gas to facilities and pipelines on shore[69]. They are highly customizable to meet a variety of parameters including flow rate, storage volume, mooring, etc. Table 2 provides examples of FSRU vessels put into service. Storage capacity of FSRUs ranges from 125,000 m^3 to 170,000 m^3.

Table 2. FSRU Examples

Ship Name	Excelsior	Excellence	Excelerate	Explorer
Year Built	January 2005	May 2005	October 2006	March 2008
Cargo Capacity (100%)	138,000 cubic meters (m^3)	138,000 m^3	138,000 m^3	150,900 m^3
Length (meters)	277.00	277.00	277.00	291.00
Beam (meters)	43.4	43.4	43.4	43.4
Draft (meters)	12.32	12.32	12.32	12.4
Deadweight Tonnage (metric ton [mt])	77,288	77,288	77,288	82,000
Gross Tonnage (mt)	93,719	93,719	93,719	108,000
Service Speed (knots)	19.1	19.1	19.1	19.1

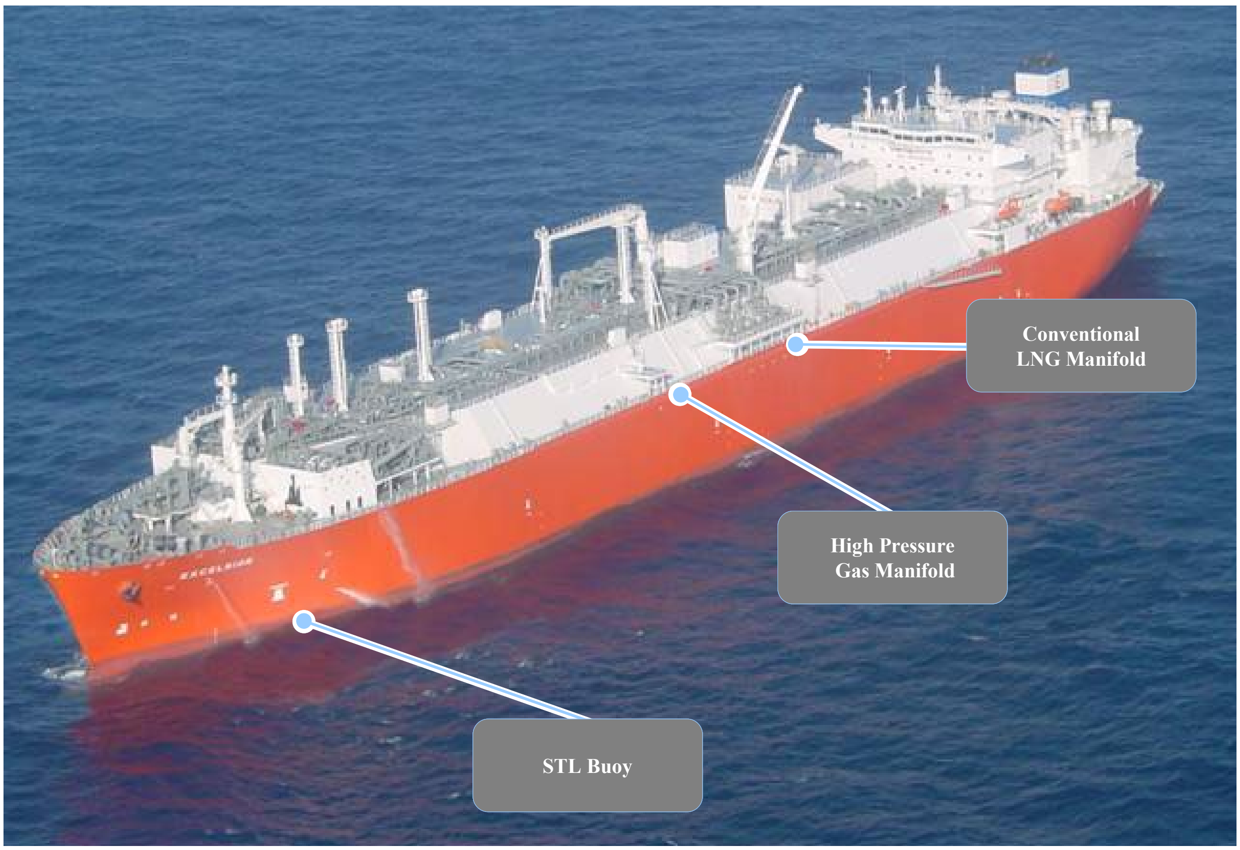
[69] FSRU - Excelerate Energy

A typical FSRU stores about 138,000 m^3 of LNG, which converts to approximately 2.8 billion cubic feet of natural gas. Discharge pressure is up to 1,000 pounds per square inch gauge (psig) at a temperature of 40 degrees Fahrenheit (°F).

Figure 18 depicts the "Excelsior" LNG FSRU showing:

- The compartment for the submerged turret loading (STL) buoy for gas transfer to onshore via a subsea pipeline.
- The high-pressure manifold for transfer of gas on a dockside application.
- A conventional LNG manifold for LNG ship-to-ship transfer via flexible hoses.

Figure 18. Overview of Gas Transfer Connections



LNG Transfer

Since 2006, composite hoses have been used for the transfer of LNG from ship to ship in benign environments for small and medium-scale LNG services.

Figure 19. Ship-to-Ship Transfer via Flexible Hoses

Loading and unloading of LNG carrier (LNGC) vessels in an offshore location is challenging and includes several risks. Due to dynamic motion inherently associated with the LNGC and FSRU while connecting, disconnecting, and transferring LNG, accidents can happen through a marine transfer hose during any of the operational phases. Operational issues related to the high-dynamic motions involved in offshore LNG transfer are an important safety concern, which should be investigated in detail. It is critical to review the terminal site's weather data and historical events thoroughly to assess the effects of waves, wind, and tide and identify the required design features for the selected marine transfer system.

LNGC Vessels

An LNGC vessel, otherwise known as an LNG tanker, carrier, or ship, is designed to transport LNG from one location to another. They vary from typical cargo ships in many ways owing to the necessary equipment to load and unload, store, and handle a cryogenic fluid. These vessels maintain an incredible safety record. Over the more than 50-year history of delivering LNG across the world via ship, vessels have traveled over 150 million miles without major incident[70]. Pictured in Figure 20 is an example of an LNGC.

Figure 20. LNGC – "Marvel Pelican"[71]

Summary of Work

This section summarizes the work that ultimately led to the final solution proposed in the following Final Supply Chain Summary section of this report, providing a greater context into the various considerations throughout the evaluation.

The initial driver for the required LNG infrastructure was the natural gas demand for the State. This included multiple factors such as onshore storage volume and technique, pipeline size, FSRU size, etc. HDR was provided with previously compiled reference documentation to begin the analysis. After noting discrepancies in the documentation, the team endeavored to establish its own natural gas demand estimations for the state to create "bookends" to design toward. These bookends were the foundation for the scenario design moving forward.

The team began with Oʻahu. It was apparent an FSRU would be ideally suited to serve the island's natural gas storage needs. Excelerate Energy, experts in floating storage and regasification, were consulted to aid in cost estimation, proper sizing, and applications of the FSRU.

Initially, the teams plan for Oʻahu included:

[70] 2015, 06-30 LNG Safety

[71] MARVEL PELICAN, LNG Tanker – Details and current position – IMO 9759252 – VesselFinder

- An FSRU moored off Barbers Point, including a subsea pipeline to connect the FSRU to the island.
- An onshore LNG import terminal with a field-erected storage tank and vaporization equipment at Pier 9 in Barbers Point Harbor.
- New and repowered natural gas power generation facilities on Oʻahu.
- New onshore underground natural gas pipelines creating a network between the subsea line, the import terminal, and natural gas power generation facilities.

Concerns regarding a single point of failure at any one power generation facility and the increased permitting and community challenges associated with a large onshore storage tank were discussed. This, along with further analysis of neighboring islands and other variables resulted in an amended approach. This phased design incorporated the following.

Phase 1 – Oʻahu:

- An FSRU moored off Barbers Point, including a subsea pipeline to connect the FSRU to the island.
- A new natural gas power generation facility.
- New onshore underground pipeline connecting the subsea line to the natural gas power generation facility.

Phase 2A – Oʻahu:

- An articulated tug barge (ATB) route from the FSRU to a new ATB/LNG import terminal.
    - ATB would transfer LNG to ISO containers for transport
- New natural gas power generation facility
- New onshore underground pipeline connecting the new power generation facility to the natural gas supply pipeline network.

Following feedback from HSEO, the neighboring islands were removed from consideration and the final phased approach outlined in the following Final Supply Chain Summary section was developed. Many additional items were removed from consideration to avoid over buildout of infrastructure and to save capital costs.

Final Supply Chain Summary

The final supply chain process described below is the result of an iterative process described earlier in the Summary of Work section. The final solution was split into two phases, Phase 1 is scheduled to be in-service in 2030 with Phase 2 following in 2035. HDR developed the phased approach to allow for additional flexibility for updated energy demands, technological advancements, and other driving information as it becomes available over the next decade. The effectiveness of the solution is heavily reliant on the island’s cumulative natural gas demand. Below Table 3 and Table 5 show the estimated natural gas demand for the facilities to be introduced to Oʻahu during each phase. HDR calculated these values based on proposed facilities generation capacity, expected facility efficiency, heat rate values, facility capacity factors, etc.

Existing fuel oil storage will be left in place and utilized for fuel backup needs and new engines would all be dual fuel engines able to switch between gas and diesel or biodiesel if necessary for backup. Keeping in mind the overarching goal set in the RPS, natural gas turbines and other infrastructure will be compatible with hydrogen service for a future conversion to hydrogen-based power generation. Pipelines may be

Phase 1

Phase 1 introduces natural gas on a large scale to the island of Oʻahu. An FSRU with a storage volume of about 180,000 m^3 will be moored about two miles off Barbers Point. An advanced buoy system will be installed to verify safe operation. In detailed design, HDR will further analyze the waters in which the FSRU will be moored. This vessel will be the island's main source of natural gas for power generation purposes. Detailed specifications of the FSRU will be determined during detailed design. The FSRU will be filled via LNGC at regular intervals to maintain the stored volume. The product will be sourced most likely from Canada or Mexico due to Jones Act requirements. A subsea pipeline will be built to connect the FSRU to the existing and new pipeline network on Oʻahu, and this pipeline will be sized to accommodate the design send-out flow rate from the FSRU. Based on preliminary calculations shown below in Table 3 and Table 5 the pipeline will have a diameter of 16 inches, and these calculations will need refined and confirmed during detailed design.

During Phase 1, natural gas power plants will be modified and developed at two locations: the KPLP and Barbers Point Combined Cycle site (De-commissioned Coal Plant). KPLP currently operates a 208 megawatt (MW), combined-cycle co-generation plant that combusts low sulfur fuel oil (LSFO)[72]. The facility will be modified with natural gas-burning infrastructure including burners, compressors, gas skids, piping, etc. The De-commissioned coal plant was previously a medium-sized, coal-fired electrical power station but was closed in September of 2022[73]. A 2 x 1 combined-cycle natural gas power plant with a simple cycle peaking unit will be built at this location. Table 3 provides power generation and gas demands for both proposed power plants.

[72] What We Do | Kalaeloa Partners Lp

[73] AES Marks the Retirement of Hawaiʻi Power Plant While Expanding with Renewable Energy Projects Statewide | AES Hawaiʻi

Table 3. Phase 1 Power Plant Data

Location	Total Capacity (MW)	Required Flow Rate (million standard cubic feet per day [MMscfd])	LNG Volume (million gallons per year [MMgpy])	Total Generation (terawatt hours [TWh])
KPLP	208	22.2	97.6	1.1
Barbers Point Combined Cycle	156 60	13.6 1.2	59.9 5.3	0.82 0.06
Total	**424**	**37**	**162.8**	**1.98**

A new pipeline will be installed to connect both KPLP and the Barbers Point Combined Cycle locations to the existing natural gas transmission network, connecting both sites to the natural gas supply from the FSRU.

A summary of the capital expense (CAPEX) for Phase 1 is shown in Table 4. These numbers are considered preliminary and will need further refining during detailed design and engineering.

Table 4. Phase 1 LNG Assets Capital Costs, undiscounted present value.

Description	CAPEX
FSRU, Buoy System, Subsea Pipeline	$412,000,000
Onshore pipeline connection to KPLP	$2,000,000
Onshore pipeline connection to Barbers Point Combined Cycle	$10,000,000
Transmission system upgrades	$20,000,000
KPLP Power Plant Conversion - Burner replacements with new gas infrastructure (compressor, gas skids, piping)	$20,000,000
Barbers Point Combined Cycle Power Plant	$570,000,000
Additional storage and additional contingency	$12,000,000
Phase 1 Total	**$1,046,000,000**

Phase 2

The second phase will supplement the new natural gas infrastructure introduced to Oʻahu during Phase 1. The FSRU and associated subsea pipeline installed during Phase 1 will be sized with the capacity to serve the demands of both phases. So, it will remain in place from its introduction in Phase 1 through the lifecycle of natural gas usage on Oʻahu.

Phase 2 will introduce natural gas power generation to both the CIP and Kahe facilities. The CIP location will be modified to house new burners for a single-cycle gas turbine. The Kahe facility will incorporate a new 3 x 1 combined cycle natural gas power generation system. Table 5 provides additional information on the updated power plant. A pipeline will be built to connect the CIP and Kahe facilities to the existing natural gas pipeline network and the FSRU's gas supply. A summary of the capital expense for Phase 2 is shown in Table 6. These numbers are considered preliminary and will need further refined during detailed design

Table 5. Phase 2 Power Plant Data

Location	Total Capacity (MW)	Required Flow Rate (MMscfd)	LNG Volume (MMgpy)	Total Generation (TWh)
CIP	129	3.4	15.1	0.1
Kahe	358	34.2	150.6	1.9
Total	**487**	**37.6**	**165.7**	**2.0**

Table 6. Phase 2 LNG Assets Capital Costs, Undiscounted Present Value

Description	CAPEX
Onshore pipeline connection to CIP	$2,000,000
Onshore pipeline connection to Kahe	$20,000,000
Campbell Industrial Park Power Plant Conversion - Burner replacement with new gas infrastructure (compressor, gas skid, piping)	$10,000,000
Kahe Combined Cycle Power Plant	$945,000,000
Transmission system upgrades	$44,000,000
Additional storage and additional contingency	$18,000,000
Phase 2 Total	$1,039,000,000

Conclusion

The phased approach outlined in the Final Supply Chain Summary section provides a conservative, viable path forward for the implementation of a lower cost and carbon power generation alternative to residual fuel powered generation on Oʻahu. Natural gas is the only viable bridge fuel to replaced low sulfur fuel oil as Hawaiʻi stives towards its RPS targets. By removing oil price volatility, this approach lessens the overall burden on the ratepayer, provides a resilient and reliable source of energy, while reducing greenhouse gas emissions when compared to current power generation techniques. It also provides the necessary and prudent fuel flexibility required when planning an energy future for a state over an extended period. Table 7 provides the cumulative natural gas demands, LNG volumes, CAPEX, etc. for both phases outlined in the Final Supply Chain Summary section.

Table 7. Cumulative Phase 1 and 2 Information

Description	CAPEX
Total Capacity (MW)	911
Total Required Flow Rate from FSRU (MMscfd)	74.6
Total LNG Volume Demand (MMgpy [million tons per annum {MPTA}])	328.5 [0.53]
Total Power Generation (TWh)	3.98
Total CAPEX ($)	**$500,000,000**

Appendix E - Biodiesel and Renewable Diesel

Summary

This Technical Documentation introduces biodiesel and renewable diesel as fuels that could be used for electric generation in Hawaiʻi. Currently, Pacific Biodiesel produces 5.5 to 6 million gallons per year (MMGAL/YR) of biodiesel in Hawaiʻi from both local and imported feedstock. In a 2024 request for proposal, Hawaiian Electric (HECO) is looking to increase biodiesel consumption to 12 MMGAL/YR for use at plants statewide.[74] However, these figures are relatively small compared to the 497 MMGAL/YR of total fossil fuel oil consumption for electric generation statewide.

As part of examining future options for low-carbon electricity, HDR looked at potential biodiesel feedstocks and land availability for local production. About half of the current designated agriculture land is not currently being utilized for crops or pasture and could theoretically be utilized for biofuel feedstock production. For calculating relative land use intensity, palm oil was chosen as a high-yield proxy for feedstock production, and a tabletop calculation showed 420-megawatt hours (MWh) of energy generation could be attained with 67 acres of palm oil or 1 acre of photovoltaic (PV) solar. Other feedstocks could theoretically be used in Hawaiʻi but likely with smaller energy yields per acre of land.

The import market to Hawaiʻi was also considered. The United States is currently a net importer of biodiesel, which is driven by regulatory initiatives like California's low carbon fuel standard. Hawaiʻi will need to look for additional supply options, which could include import options from Asia. Pricing of oil feedstocks and biodiesel tends to be linked to petroleum markets due to substitutability.

Considering land use and economic constraints, biodiesel (and other biofuels) may be put to higher use in harder-to-decarbonize sectors like heavy-duty ground transportation, heavy-duty equipment at ports, and aviation.

Introduction

Biodiesel and renewable diesel can both be used as a combustion energy source, though there are distinct differences in these "renewable" fuels. Biodiesel is produced by transesterification of vegetable oils and animal fats, including used cooking oil. A variety of vegetable oils can be used including soybean, rapeseed, sunflower, and palm oil.

The US Energy Information Administration, explains further, "Pure biodiesel has limited direct-use applications and has supply logistics challenges because of its physical properties and characteristics. Biodiesel is a good solvent, which means it can degrade rubber in fuel lines and

[74] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

loosen or dissolve varnish and sediments in petroleum diesel fuel tanks, pipelines, and in engine fuel systems (which can clog engine fuel filters). Biodiesel turns into a gel at higher temperatures than petroleum diesel, which creates problems for its use in cold temperatures. So, biodiesel cannot be stored or transported in regular petroleum liquids tanks and pipelines—it must be transported by rail, vessel and barge, or truck."[75]

Renewable diesel can be produced through more diverse sources than biodiesel including virtually any biomass feedstock containing carbon. The production process uses hydrogenation to result in a product chemically similar to petroleum diesel. This process does require a hydrogen source for processing, although it has the advantage of being able to convert existing petroleum refineries to do it.[76]

Demand for biodiesel and renewable diesel continues to grow globally largely as a function of public policy support for replacing petroleum products in the transport sector driven by both climate change mitigation and energy independence goals. Policy support can come either from subsidies for fuel production or mandates governing the carbon content of fuels or specific fuel sources. Ethanol, renewable diesel, and biodiesel are the three main options for drop-in blending or fueling of the transport sector, which is a large source of biodiesel demand.[77]

As biofuel consumption is largely driven by transportation demand, the supply and pricing of biodiesel and renewable diesel are driven as a function of both petroleum pricing and policies that support the use of renewable or low-carbon fuels. As such, biofuel use and consumption tend to be mostly focused on domestic or local markets, but other factors, such as fuel policies that produce demand exceeding local supply, also support a growing export market for biofuels.

Hawaiʻi and Biodiesel

Currently, there is one refinery in Hawaiʻi that produces biodiesel: Pacific Biodiesel. This refinery has a nameplate capacity of 5.5 MMGAL/YR. In 2023, Pacific Biodiesel produced 6 MMGAL. Most of the feedstock comes from waste oils and fats, with domestic production supplemented by imported oils and fats.[78] Therefore, further supply of biodiesel to meet renewable energy and/or climate goals would either have to come through new on-island biofuel feedstocks or imports of biofuel feedstock and/or biodiesel.

Several previous studies have looked at biofuel production in Hawaiʻi with the most relevant and complete studies including a Black and Veatch study in 2010, *The Potential for Biofuels Production in Hawaiʻi* and a Hawaiʻi Agricultural Research Center (HARC) study from 2006, *Biodiesel Crop*

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[75] Biofuels explained - use and supply - U.S. Energy Information Administration (EIA)

[76] Biofuels explained - Biodiesel, renewable diesel, and other biofuels - U.S. Energy Information Administration (EIA)

[77] Transport biofuels – Renewables 2023 – Analysis - IEA

[78] Pacific Biodiesel

Implementation in Hawaiʻi. These studies provide a good fundamental understanding of the potential for biodiesel production within the state of Hawaiʻi and potential limitations.[79,80]

Hawaiʻi Agriculture and Land Use

As biodiesel production is typically rooted in agricultural activity for feedstock crops, it is important to discuss future biodiesel opportunities in the context of current agricultural practices. Hawaiʻi's agricultural industry supports both local markets and export markets. Traditional food crops and pasture lands are used to meet local dietary needs and offset the need for costly imports, which represent 90% of current consumption. The main agricultural exports include pineapple, macadamia nuts, and coffee.

As of December 2022, there were 1,931,378 acres (781,934 hectares) of land classified as "agricultural" by the State Land Use Commission.[81] However, in practice, much less of that land is used for actual agricultural practices due to topological, soil, climate, geographic, and economic constraints.

According to the *2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline,* the current amount of land used for agriculture is 886,211 acres with 120,632 acres in crop land and the remaining 765,579 acres used for pasture.[82]

Production of new energy crops for biodiesel would typically be viewed as most applicable to lands suited for crop production due to topological, soil, and water requirements.

Energy Production Capability

Based on previous studies, one of the highest-yielding crops for biodiesel and renewable diesel production is likely palm oil. Other biodiesel feedstocks are discussed later in this document. It is important to note that the production of palm oil is a controversial pathway to produce biofuels and can have extremely negative environmental impacts due to deforestation and land-use changes associated with its cultivation; however, given high-yield it was used for the basis of the analysis. Emissions from palm oil-based biodiesel are higher if forests or peatlands are cleared for plantations, releasing significant amounts of stored carbon into the atmosphere, a particular concern for imported palm oil. However, some of the environmental concerns surrounding palm oil could be alleviated by utilizing palm oil on lands previously used for agriculture.

For desktop calculation purposes, palm oil was selected because it is the most optimistic and high oil-yielding means of biofuel feedstock per unit of land area with production of approximately 600

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79 Microsoft Word - Hawaii_DBEDT_--_Final_HI_biofuels_Report_rev7.doc

80 Microsoft Word - biodiesel report.doc (hawaii.gov)

81 section06.pdf (hawaii.gov)

82 2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline (hawaii.gov)

gallons per acre/per year. This is supported by initial production testing in Hawaiʻi showing rates of 620 to 650 gallons per acre.[83] Palm oil would require several years for oil production to ramp up.

Converting palm oil to biodiesel via esterification results in a yield of approximately 87% by volume. The biodiesel energy content is 119,550 British thermal units per gallon (btu/gal) for biodiesel and 123,710 btu/gal for renewable diesel.[84] Therefore, assuming the conversion factors above, converting palm oil to biodiesel via esterification would equate to 62.4 metric million Btu per acre (MMBtu/acre) per year of energy. Assuming the biodiesel was used in a power plant with a heat rate of 10 MMBtu/MWh, one acre of palm oil crop would produce 6.24 MWh or 67 times more land for the same 420 MWh of electricity generation.

Palm oil on average exhibits yields (gal/acre) estimated to be approximately ten (10) times higher than camelina, five (5) times higher than rapeseed/canola, thirteen (13) times higher than soy, and about three (3) times higher than that of Jatropha.[85] Utilizing these crops would increase the land use requirements for growth.

Converting palm oil to biodiesel via esterification results in a yield of approximately 87% by volume. The biodiesel energy content is 119,550 British thermal units per gallon (btu/gal) for biodiesel and 123,710 btu/gal for renewable diesel.[86] Therefore, assuming the conversion factors above converting palm oil to biodiesel via esterification would equate to 62.4 metric million Btu per acre (MMBtu/acre) per year of energy.

$$600\ \left[\frac{gal-oil}{year}\right]\cdot 0.87\ \cdot 119{,}550\ \left[\frac{Btu}{gal}\right]\cdot\frac{1}{1{,}000{,}000}\ \left[\frac{MMBtu}{Btu}\right] = \mathbf{62.4}\ \left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre-year}}\right] \quad (1)$$

Assuming the biodiesel was used in a power plant with a heat rate of 10 MMBtu/MWh, 1 acre of palm oil crop would produce 6.24 MWh.

$$62.4\ \left[\frac{MMBtu}{acre-year}\right]\cdot\frac{1}{10}\ \left[\frac{Btu}{MMBtu}\right] = \mathbf{6.24}\ \left[\frac{\boldsymbol{MWh}}{\boldsymbol{year}}\right] \quad (2)$$

[83] About Us (hawaiioilseedproducers.com)

[84] Alternative Fuels Data Center: Fuel Properties Comparison (energy.gov)

[85] Hawaii Natural Energy Institute. (2013). *Biofuels crop assessment*. University of Hawaiʻi Hawaiʻi Energy and Environmental Technologies Initiative. Retrieved from https://www.hnei.hawaii.edu/wp-content/uploads/Biofuels-Crop-Assessment.pdf

[86] Alternative Fuels Data Center: Fuel Properties Comparison (energy.gov)

6.24 MWh roughly equates to the annual electric use of one residential customer per acre of palm oil production.

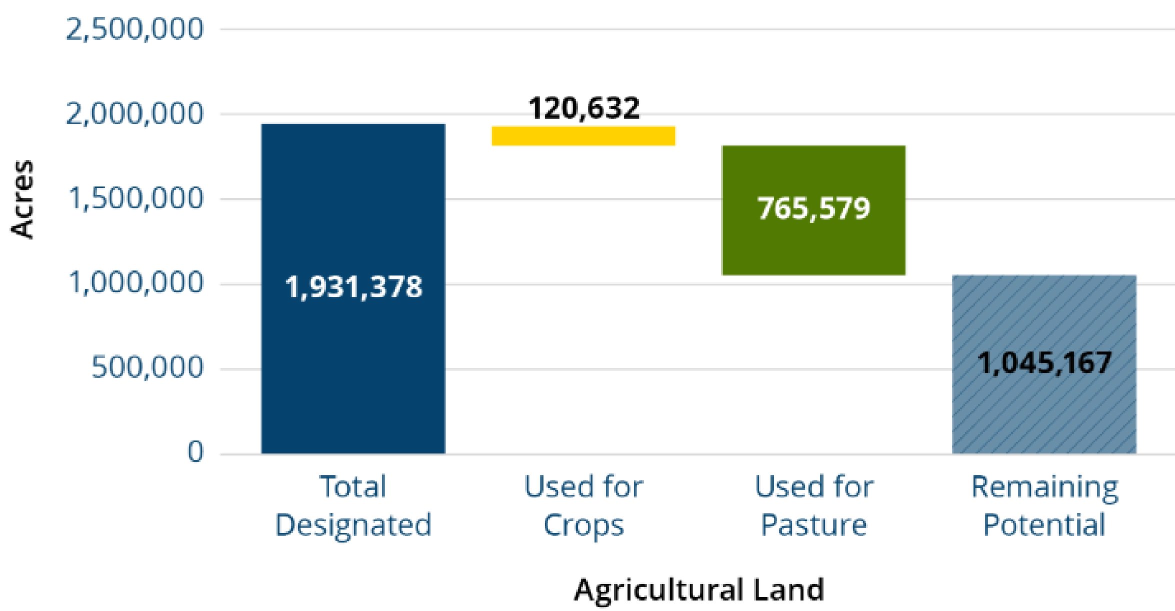
To contrast with respect to total Hawaiʻi electricity consumption and land use, Hawaiʻi consumes 10,819 gigawatt hours (GWh) of gross electricity per year.[87]

Therefore, to replace just 5% of total energy consumption with biodiesel would require 86,691 acres of new crop land.

$$0.05 \cdot 10{,}819\,[GWh] \cdot 1{,}000 \left[\frac{MWh}{GWh}\right] \cdot \frac{1}{6.24} \left[\frac{acre - year}{MWh}\right] = \mathbf{86,691}\ [\boldsymbol{acres}] \tag{3}$$

Hawaiʻi currently has 120,632 acres in farmland, see Figure 1.

Figure 1. Land capacity use statewide



The new acreage required solely for bioenergy through palm oil production would result in a 72% increase in crop land.

$$\frac{86{,}691\,[acres]}{120{,}632[acres]} = \boldsymbol{72\%\ increase\ in\ crop\ land} \tag{4}$$

[87] ElectricityTrendsReport2023.pdf (hawaii.gov)

Increasing biofuel production in Hawaiʻi would require substantial public policy, regulatory, and economic decisions to incentivize demand. However, this demand would also place economic pressure on the existing agriculture industry as land prices would increase in response to a new demand for crop production. This would result in shifts in the agriculture output, which would likely result in higher prices for non-biofuel agricultural products.

There are also additional tradeoffs to consider as Hawaiʻi looks to decarbonize the entire economy. Liquid biofuels can be used for electric generation, but they can also be used as a low carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels since hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there might be competing demands for biofuel production from other sectors that would be willing to pay a premium for the fuel or feedstock as they attempt to decarbonize.

Solar Comparison to Biodiesel

Since land use in Hawaiʻi is subject to competing interests in balancing urban development, industry, agriculture, tourism, recreation, biologic preservation, and agriculture, it can be useful to compare land requirements between substitute activities. In the case of biofuel production for electricity, PV solar energy is a competing energy source.

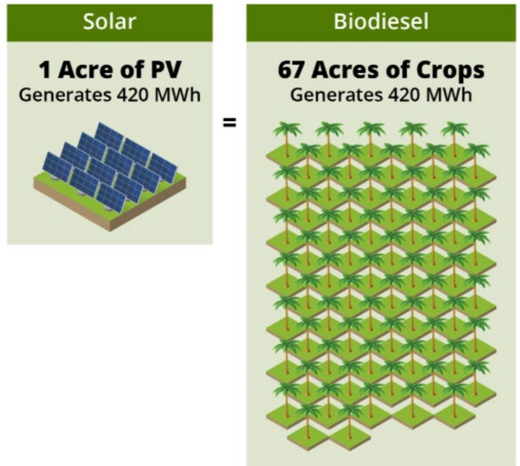
Assuming a solar PV capacity factor of 24% and a power density of 0.2 megawatt alternating current (MWac) per acre, one acre of a PV installation can produce 420 MWh per year.

$$0.2\ \left[\frac{MWh}{acre}\right] \cdot 0.24 \cdot 8{,}760\ \left[\frac{hours}{year}\right] = \mathbf{420}\ \left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre - year}}\right] \tag{5}$$

This means the equivalent electrical output from the same amount of land is approximately 67 times greater for solar PV than from biofuel production.

$$\frac{420\ \left[\frac{MMBtu}{acre - year}\right]}{6.24 \left[\frac{MMBtu}{acre - year}\right]} = \mathbf{67} \tag{6}$$

Figure 2. Land comparison, solar versus biodiesel



Other Biodiesel Feedstocks

For evaluating potential land use impacts of domestic biofuel production, palm oil was chosen due to its wide-spread cultivation in climates similar to Hawaiʻi, high relative productivity per acre, and prevalent commercial use as a biofuel feedstock. Past work by Black & Veatch and the University of Hawaiʻi[88] as well as HARC[89] have previously examined other potential sources of biofuel feedstock for production in Hawaiʻi.

Many different feedstocks are used for biodiesel production worldwide with soybean, rapeseed, and corn oils as major bio-oil-based feedstocks (other than palm oil) used in global biodiesel production.[90] However, these crops are typically produced in more temperate climates than Hawaiʻi and typically have smaller oil yields than what has been demonstrated with palm oil. As with any biofuel feedstock or biofuel, import could be an option, though market conditions will dictate pricing, and as a petroleum substitute, biofuel pricing is linked to crude oil pricing.

Small pilot projects with other alternative biofuel feedstocks have begun to emerge in recent years in Hawaiʻi to further investigate the viability of local commercial production. One such feedstock is from the beans of the Pongamia tree, which is native to southeast Asia, Australia, and western pacific islands. The Terviva company is looking to develop these trees as a biofuel feedstock and is currently growing Pongamia trees on former pineapple and sugar plantations in Hawaiʻi.[91] While research is ongoing, it is hopeful the oil yields could approach those of palm oil with these trees growing in less productive soils.[92]

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[88] https://energy.hawaii.gov/wp-content/uploads/2011/10/Hawaii-Biofuels-Assessment-Report.pdf

[89] https://hdoa.hawaii.gov/wp-content/uploads/2013/01/biodieselreportrevised.pdf

[90] Total biofuel production by feedstock, main case, 2021-2027 – Charts – Data & Statistics - IEA

[91] https://terviva.com/

[92] https://www.fastcompany.com/90871132/these-supertrees-grow-a-climate-friendly-alternative-to-palm-oil

Another biofuel feedstock emerging for potential use in Hawaiʻi is camelina, or false flax, which is an annual plant producing oil-rich seeds. Pono Pacific and Par Hawaiʻi are currently exploring development of camelina in local production of sustainable aviation fuel. The hope is to use camelina as a rotational cover crop to complement existing agricultural activities.[93] Based on research by HARC on similar crops, camelina yields on Hawaiʻi would likely be significantly less than could be provided by palm oil; hence, its investigation as a rotational crop to supplement other crops.

Additional research and plantings will need to demonstrate the commercial viability of dedicated energy crops within Hawaiʻi (palm, Pongamia, camelina, or otherwise). Each biofuel feedstock will have certain characteristics that govern its productivity, cost, and utilization. As such, commercial production may utilize several different oil sources.

Renewable and Biodiesel Imports

Renewable and biodiesel demand can also be met with imported fuels and feedstocks. Biodiesel production sources are typically geared toward specific markets with the bulk of the United States' current biodiesel production coming from soybean oil, Europe utilizing rapeseed oil, and southeast Asia favoring palm oil.

Indonesia and Malaysia dominate palm oil production accounting for greater than 80% of global production. This production also supports renewable diesel production abroad with almost all renewable diesel imported to the United States currently coming from a Neste facility in Singapore. The United States also receives smaller supplies of biodiesel from Canada, Germany, Spain, and Italy.

The United States is a current net importer of biofuels, and its current biodiesel production capacity sits at about 2,000 MMGAL[94]; however, US production capacity has been steadily decreasing since its peak capacity of 2,600 MMGAL in July 2019.[95]

For comparison, Hawaiʻi consumed a combined 497 MMGAL/YR of low sulfur fuel oil (LSFO), high sulfur fuel oil (HSFO), diesel, and naphtha fuels.[96] HECO's latest request for proposal for biodiesel

[93] https://www.khon2.com/local-news/a-new-initiative-in-hawai%CA%BBi-could-change-our-carbon-footprint/

[94] US Biodiesel Plant Production Capacity. EIA. (2024, August 15). https://www.eia.gov/biofuels/biodiesel/capacity/

[95] EIA. (2024, September 10). Petroleum & Other Liquids. US biodiesel production capacity (million gallons). https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M

[96] Data from Hawaiian Electric. (January 31, 2024). Consolidated Annual Fuel Report, DKT 2022-0014, Page 10 of 60. HDR calculations using assumption that 1 barrel is equivalent to 42 US gallons.

imports to Hawaiʻi was for 285,000 barrels per year or about 12 MMGAL/YR.[97] Table 8 and Table 9 below summarize these figures.

Table 8 Fuel use for energy generation on the five islands served by HECO[22]

Fuel	2023 Consumption (barrels)	2023 Consumption (gallons)
LSFO	8,562,045	359,605,890
HSFO	630,292	26,472,264
Diesel	2,289,303	96,150,726
Naphtha	348,872	14,652,624
FOSSIL FUEL TOTAL	11,830,512	496,881,504

Table 9 Biodiesel use for energy generation on the five islands served by HECO versus HECO's 2024 RFP[21,22]

Fuel	Consumption (barrels)	Consumption (gallons)
2023 Biodiesel Consumption	133,978	5,627,076
HECO's 2024 RFP for Biodiesel	285,000	11,970,000

To replace a meaningful percentage of 497 MMGAL/YR of fossil-based fuel oil, Hawaiʻi will have to significantly increase its import quantities requested in its current proposals. This increase would come at a significant cost because of competition from states like California that have financial incentives to consume biofuels and midwestern states like Iowa, where customers would benefit from shorter shipping distances.

[97] Request for proposals - fuels supply. Hawaiian Electric. (2024, August 23). https://www.hawaiianelectric.com/clean-energy-hawaii/request-for-proposals---fuels-supply

Appendix F - Biogas and RNG

Summary

This Technical Documentation summarizes biogas and renewable natural gas (RNG) as fuels that could be used for electric power generation in Hawaiʻi. Currently, Hawaiʻi produces wastewater biogas, landfill gas, and syngas that supplement imported fossil natural gas (NG). However, Hawaiʻi's use of natural gas is very small and makes up less than 2% of its overall energy portfolio.[98]

The Honouliuli Wastewater Treatment Plant located on Oʻahu produces 800,000 therms of RNG from municipal biosolids. Hawaiʻi is striving to become net zero by 2045 and looking to increase RNG production for use at power plants as well as supplement other energy uses statewide. The current RNG production figures are relatively small compared to the 497 million gallons per year (MMGAL/YR) of total fossil fuel oil consumption for electric generation statewide.

As part of examining future options for low-carbon electricity, HDR looked at potential RNG production from various feedstocks and land availability for local production. About half of the current designated agriculture land is not currently being utilized for crops or pasture and could theoretically be utilized for energy crop feedstock production. For calculating relative land use intensity, HDR chose Bana grass, or cane grass, as a high-yield proxy for feedstock production. A tabletop calculation showed 420 megawatt hours (MWh) of energy generation could be attained with 24 acres of Bana grass or 1 acre of photovoltaic (PV) solar. Other feedstocks could theoretically be used in Hawaiʻi but likely with smaller energy yields per acre of land.

HDR also considered the import market to Hawaiʻi. The United States currently produces RNG as a supplement to a large NG demand domestically, but the exportation of RNG internationally is becoming attractive and driven by regulatory initiatives in Europe.

Considering land use and economic constraints, RNG may be put to higher use in harder-to-decarbonize sectors like transportation, heavy-duty equipment at ports, airports, and other areas.

Hawaiʻi and RNG

Currently, there is one facility in Hawaiʻi that produces RNG: the Honouliuli Wastewater Treatment Plant (WWTP) on Oʻahu. This facility treats an average daily wastewater flow of 26 MMGAL per day and can produce 800,000 therms per year of RNG. In its first full year of operation (2020), the Honouliuli WWTP produced 382,000 therms of RNG, which was injected into a Hawaiʻi Gas Pipeline. The feedstock for the RNG production comes from the anaerobic digestion of biosolids produced during treatment.

[98] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Several previous studies have looked at RNG production in Hawaiʻi with the most relevant and complete study being a Hawaiʻi Natural Energy Institute of the University of Hawaiʻi 2021, *Resources for Renewable Natural Gas Production in Hawaiʻi*. This study provides a good fundamental understanding of the potential for RNG production within the state of Hawaiʻi and potential limitations.[99]

RNG Production from Wastes

RNG is composed primarily of methane produced from either biological or elal conversion of organic feedstocks. RNG has lower life cycle greenhouse gas (GHG) emissions than fossil NG and has become an attractive method of reducing the carbon emissions of communities globally. RNG from biological or thermal conversion can both be used as a combustion energy source as a NG replacement for heating or vehicle fuel or to produce electrical power with internal combustion engines or turbines. The end use of RNG will dictate the quality required and the levels of contaminant removal. Many RNG production facilities recycle the gas for on-site power generation and heat recovery.

For on-site electrical production, a low British thermal unit (Btu) (500 to 650 Btu per cubic feet [cu ft]) RNG can be utilized with minimal gas conditioning for removal of hydrogen sulfide, moisture, and siloxane removal. End uses requiring transportation via trucks or a pipeline for NG replacement or vehicle fuels will require additional gas conditioning to remove the CO2 and other contaminants and produce a high Btu (900 to 1,010 Btu/cu ft) RNG of NG quality.

For the US mainland, high-Btu RNG has unlimited direct-use applications and minimal supply logistic challenges because of its nearly identical physical properties and characteristics to fossil NG. In Hawaiʻi, RNG direct-use applications may be limited by the overall lower NG volumes used in comparison to other energy sources like wind, solar, and non-NG, petroleum-based fuels.

Demand for RNG continues to grow globally largely as a function of public policy support for replacing petroleum products in the transport sector driven by both climate change mitigation and energy independence goals. Policy support can come either from subsidies for fuel production or from mandates governing the carbon content of fuels or specific fuel sources.

As RNG consumption is largely driven by transportation demand, the supply and pricing of RNG is driven as a function of both petroleum pricing and policies that support the use of renewable or low carbon fuels. As such, RNG use and consumption tend to be mostly focused on domestic or local markets, but other factors, such as fuel policies that produce demand exceeding local supply, also support a growing export market for RNG.

The potential additional RNG production in Hawaiʻi for this study is based on the availability of organic feedstocks already produced within the state or those that could be produced with a

[99] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

change in land use. HDR assumes it would not be financially feasible, or practical, to import feedstocks to produce RNG locally. Importing RNG as LNG or NG from the mainland or other sources is covered in other HDR Technical Memorandums. To estimate the additional RNG production potential in Hawaiʻi, HDR evaluated the available quantities of the various feedstocks for either biological or thermal conversion to RNG. Feedstocks for biological conversion include livestock manure, municipal biosolids from WWTPs, food wastes diverted from municipal solid waste, and municipal solid waste that produces landfill gas. Feedstocks evaluated for the thermal conversion to RNG include urban fiber sources, agricultural residues, and energy crops. The Hawaiʻi Natural Energy Institute study on potential RNG production was a key reference for most of these feedstocks with information supplemented from other publicly available sources.

Livestock Manure

In areas with large numbers of confined animal feeding operations (CAFOs), livestock manure can be a valuable feedstock for RNG production. The mainland United States has seen dramatic increases in RNG production from dairies and hog farms in the last five years.[100] However, the Hawaiʻi Natural Energy Institute study reviewed the livestock populations in Hawaiʻi for cattle, chickens, and hogs and determined Hawaiʻi has insufficient number and size of animal feeding operations to justify biogas generation and RNG.

WWTPs

The State of Hawaiʻi has 12 WWTPs treating an average daily flow greater than 1.0 MMGAL per day (MGD).[101] Eight of these facilities already produce biogas through the anaerobic digestion of biosolids. Table 10 summarizes the biogas production potential from wastewater treatment regardless of the use of anaerobic digestion as it could be added to the facilities that don't currently have that capability.

Table 10. Biogas Production Potential of Wastewater Treatment

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Sand Island	Honolulu	Yes	76.00	194,186	886,693	616
Honouliuli	Honolulu	Yes	25.70	65,674	299,879	208
Kailua	Honolulu	Yes	16.30	41,645	190,160	132
Waianae	Honolulu	Yes	3.80	9,719	44,381	31
East Honolulu	Honolulu	Yes	4.41	11,272	51,470	36

[100] https://www.epa.gov/agstar/agstar-data-and-trends

[101] EPA 2022 Clean Water Needs Survey Report to Congress, 2022

Facility Name	County	Has Anaerobic Digestion	Average Flow (MGD)	Biogas Potential (MMBtu/year)	Biogas Standard Cubic Feet (SCF)/day	Biogas SCF/ Minute
Schofield	Honolulu	Yes	2.40	6,142	28,046	19
Lāhainā	Maui	No	4.20	10,732	49,004	34
Wailuku-Kahului	Maui	No	3.91	9,989	45,614	32
Kihei	Maui	No	3.59	9,179	41,915	29
Hilo	Hawaiʻi	Yes	4.20	10,732	49,004	34
Kealakehe	Hawaiʻi	No	1.69	4,320	19,725	14
Līhuʻe	Kauaʻi	Yes	1.11	2,835	12,944	9
TOTAL			**147**	**376,425**	**1,718,835**	**1,194**

Food Waste

Food waste includes kitchen trimmings, plate waste, and uneaten prepared food from restaurants, cafeterias, and households as well as unsold and spoiled food from stores and distribution centers and loss and residues from food and beverage production and processing facilities (USEPA, 2020). The City and County of Honolulu defines food waste as "all animal, vegetable, and beverage waste which attends or results from the storage, preparation, cooking, handling, selling or serving of food. The term shall not mean commercial cooking oil waste or commercial fats, oils and grease (FOG) waste."[102]

Food waste currently landfilled in Hawaiʻi could be converted to RNG with anaerobic digestion. Based on the assumptions listed below, currently disposed of food waste totals could support the production of about 326,000 MMBtu per year of methane production via anaerobic digestion (Table 11).

Table 11. Potential RNG Production from Food Waste via Anaerobic Digestion[103]

Description	Units	Value
Municipal Solid Waste Landfilled	tons/year	617,408
Food Waste Landfilled	tons/year	92,893
Percent Recovery	%	50
Food Waste Diverted to Anaerobic Digestion	tons/year	46,447
Biogas Production	million cu ft/year	592

[102] City and County of Honolulu – Food Waste Tip Sheet, 2021

[103] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

Description	Units	Value
RNG Production	MMBtu/year	325,710

Landfill Gas

The State of Hawaiʻi has 15 municipal solid waste landfills, seven of which are closed and not receiving additional waste.[104] For effective landfill gas collection and RNG production, HDR assumed candidate landfills have over 1.0 million tons of waste in place and have not been closed for more than 12 years. Table 12 summarizes the RNG production potential from landfill gas.

Table 12. RNG Production Potential from Landfill Gas

Landfill Name	Landfill Owner Organization(s)	Waste in Place (tons)	LFG Collection System in Place?	Current Project Status	Landfill Gas Produced (SCF/day)	Landfill Gas Produced (MMBtu/year)
Central Maui Landfill	Maui County, HI	6,564,409	Yes	Planned	1,356,000	247,470
Kapaʻa and Kalaheo Sanitary Landfills	City and County of Honolulu, HI	5,838,786	Yes	Shutdown	348,312	63,567
Kekaha Landfill/Phases I & II	County of Kauai, HI	3,113,967	Yes	Candidate	642,000	117,165
Palailai Landfill	Grace Pacific Company	2,845,215	Yes	Low Potential	70,000	12,775
South Hilo Sanitary Landfill (SHSL)	Hawaiʻi County, HI	3,193,059	No	Candidate	640,000	116,800
Waimānalo Gulch Landfill & Ash Monofill	City and County of Honolulu, HI	13,141,443	Yes	Candidate	1,121,000	204,583
West Hawaiʻi Landfill/Puʻuanahulu	Hawaiʻi County, HI	3,404,076	Yes	Candidate	304,000	55,480
Total					**4,481,312**	**817,840**

Urban Fiber Sources

Urban waste fiber resources for RNG production include the fibrous and/or combustible portion of materials disposed of as municipal solid waste (MSW) and construction and demolition waste

[104] EPA Landfill Methane Outreach Program (LMOP), 2024

(CDW). These include the drier, non-food biomass components of the waste stream (paper, cardboard, woody material, and green waste), textiles, and some plastics.

Based on the same data for solid waste composition and disposal amounts used in the food waste discussion earlier, disposal and RNG potential from the fibrous/combustible portion of the MSW stream is shown for the State in Table 4. RNG potential from this resource is approximately 4,230,000 MMBTU per year.

Table 13. Potential RNG Production from Urban Fiber Waste via Thermal Conversion[105]

Description	Units	Value
Municipal Solid Waste Landfilled	tons/year	617,408
Urban Fiber Wastes (Non-Food and Plastics	tons/year	385,766
Percent Recovery	%	90
Thermal Conversion Efficiency	%	60
RNG Production	MMBtu/year	4,230,000

Total RNG and Electrical Production Potential from Wastes

Table 5 below presents a summary of the potential RNG production potential from waste feedstocks produced within the State and the corresponding potential electrical power production. The electrical production shown assumes a generation efficiency of 40 percent. The 673,888 MWh/year of potential would be approximately 6 percent of the state's non-renewable electrical consumption[106] and roughly 74% of that production comes from the thermal conversion of urban fiber wastes. Without that feedstock, the total electrical production potential is only 178,132 MWh/year and less than 2% of the total for the state.

Table 14. Total RNG and Electrical Production from Waste

Feedstock	RNG Potential	
	MMBTU/year	MWh/year
Livestock Manure	NA	NA
WWTP	376,400	44,114
Food Waste	325,700	38,172

[105] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

[106] https://energy.hawaii.gov/what-we-do/energy-landscape/non-renewable-energy-sources/

Landfill Gas	817,800	95,846
Urban Fiber Waste	4,230,000	495,756
Total	**5,749,900**	**673,888**

RNG Production from Energy Crops

Hawaiʻi Agriculture and Land Use

As RNG production is typically rooted in the conversion of wastes, thermal conversion of dedicated energy feedstock crops also has potential and it is important to discuss future RNG opportunities in the context of current agricultural practices. Hawaiʻi's agricultural industry supports both local markets and export markets. Traditional food crops and pasture lands are used to meet local dietary needs and offset the need for costly imports which represent 90% of current consumption. The main agricultural exports include pineapple, macadamia nuts, and coffee.

As of December 2022, there were 1,931,378 acres (781,934 hectares) of land classified as 'Agricultural' by the State Land Use Commission.[107] However, in practice, much less of that land is used for actual agricultural practices due to topological, soil, climate, geographic, and economic constraints.

According to the *2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline,* the current amount of land currently used for agriculture is 886,211 acres, with 120,632 acres in cropland and the remainder, 765,579 acres used for pasture.[108]

Production of new energy crops for RNG would typically be viewed as the most applicable lands suited for crop production due to topological, soil, and water requirements.

Energy Production Capability

Based on previous studies, one of the promising crops for RNG production on island is likely sugar cane, cane grass, or Bana grass due to favorable yields in Hawaiʻi's climate. The market indicates that Bana grass could be a productive means of RNG feedstock per unit of land area, as a recent request for proposals for new RNG production led to Eurus Energy being selected to develop an RNG production facility that will utilize Bana grass as a feedstock.[109]

[107] section06.pdf (hawaii.gov)

[108] 2020 Update to the Hawaiʻi Statewide Agricultural Land Use Baseline (hawaii.gov)

[109] https://www.hawaiigas.com/posts/eurus-energy-america-and-bana-pacific-for-hydrogen-and-renewable-natural-gas-projects

Therefore, assuming 1,500 therms/acre/year for converting Bana grass to RNG via thermal gasification would equate to 150 MMBtu/acre per year of energy.[110]

Assuming that the RNG was used in a power plant with an electrical efficiency of 40 percent, 1 acre of Bana grass crop would produce 17.6 MWh.

$$15\ \left[\frac{MMBtu}{acre-year}\right]\cdot 0.293\left[\frac{MWh}{MMBtu}\right]\cdot 0.4=\mathbf{17.6}\left[\frac{\boldsymbol{MWh}}{\boldsymbol{year}}\right] \tag{1}$$

17.6 MWh roughly equates to the annual electric use of 3 residential customer per acre of Bana grass production.

In contrast with respect to total Hawaiʻi electricity consumption and land use, Hawaiʻi consumes 10,819 GWh of gross electricity per year.[111]

Therefore, replacing just 5% of total energy consumption with RNG would require 30,736 acres of new cropland.

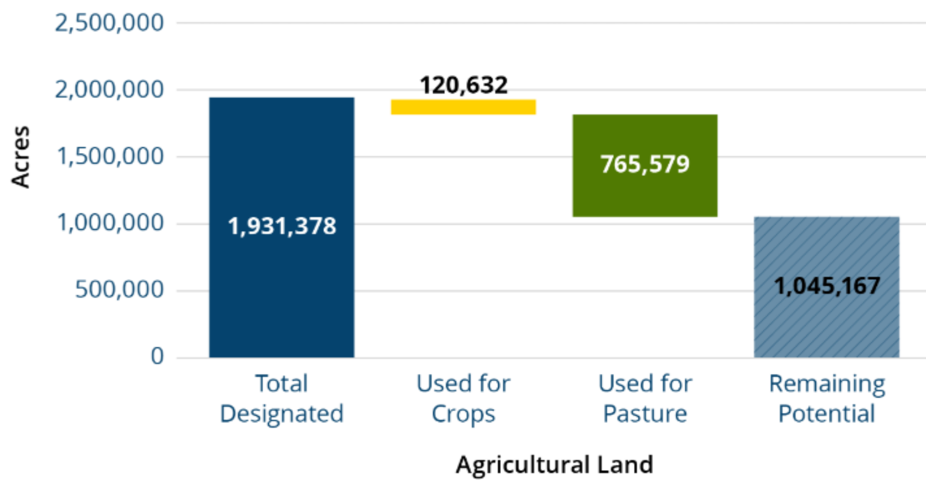
$$0.5\cdot 10{,}819\ [GWh]\cdot 1{,}000\left[\frac{MWh}{GWh}\right]\cdot\frac{1}{17.6}\left[\frac{acre-year}{MWh}\right]=\mathbf{30,736}[\boldsymbol{acres}] \tag{2}$$

As Hawaiʻi currently has 120,632 acres of farmland, see Figure 1.

Figure 1. Land Capacity Use on Hawaiʻi.

[110] Resources for renewable natural gas production in Hawaiʻi, Hawaiʻi Natural Energy Institute, May 2021

[111] ElectricityTrendsReport2023.pdf (hawaii.gov)



The new acreage required solely for bioenergy through palm oil production would result in a 25% increase in crop land.

$$\frac{30{,}736\ [acres]}{120{,}632[acres]} = \mathbf{25\%}\ \boldsymbol{increase\ in\ crop\ land} \tag{3}$$

Increasing biofuel production in Hawaiʻi would require substantial public policy, regulatory and economic decisions to incentivize demand. However, this demand would also place economic pressure on the existing agriculture industry as land prices would increase in response to a new demand for crop production. This would result in shifts in the agriculture output which would likely result in higher prices for non-biofuel agricultural products.

There are also additional tradeoffs to consider as Hawaiʻi looks to decarbonize the entire economy, while liquid biofuels can be used for electric generation, they can also be used as a low-carbon fuel in other sectors of the economy such as transport and aviation. Portions of these sectors, particularly aviation, will be hard to decarbonize with alternative fuels as hydrogen or stored electricity cannot currently provide the same energy density as liquid fuels. As such, there might be competing demands for biofuel production from other sectors that would be willing to pay a premium for the fuel or feedstock as they attempt to decarbonize.

Solar Comparison to RNG:

As land use in Hawaiʻi is subject to competing interests in balancing urban development, industry, agriculture, tourism, recreation, biologic preservation, and agriculture, it can be useful to compare land requirements between substitute activities. In the case of RNG production for electricity, PV solar energy is a competing energy source.

Assuming a solar PV capacity factor of 24% and a power density of 0.2 MWac/acre, one acre of a PV installation can produce 420 MWh/yr.

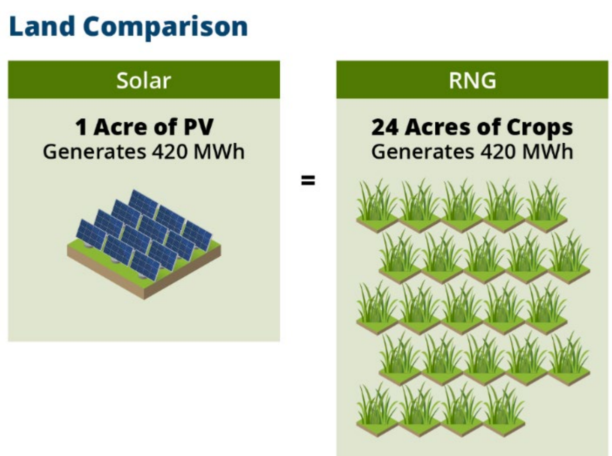
** 0.2 MWac/acre *24% * 8760 hr./yr = 420 MWh

$$0.02\left[\frac{MWh}{acre}\right]\cdot 0.24\cdot 8{,}760\left[\frac{hours}{year}\right] = \mathbf{420}\left[\frac{\boldsymbol{MMBtu}}{\boldsymbol{acre-year}}\right] \tag{4}$$

This means that the equivalent electrical output from the same amount of land is approximately 23.9 greater for solar PV than for RNG production.

$$\frac{420\left[\frac{MMBtu}{acre-year}\right]}{17.6\left[\frac{MMBtu}{acre-year}\right]} = \mathbf{23.9} \tag{5}$$

Figure 2. Land Comparison, solar versus RNG.



RNG Imports

RNG demand can also be met with imported RNG and feedstocks. RNG production sources are typically focused on specific markets with the bulk of the United States' current RNG production coming from landfill gas and biogas from anaerobic digestion.

Appendix G – Hydrogen & Ammonia Concept Summary

Liquified Natural Gas to Ammonia and Hydrogen

As the Hawaiʻi State Energy Office looks to make a transition plan from low-sulfur fuel oil to 100% renewable energy, the state currently faces significant challenges. To decrease the dependence on low-sulfur fuel oil and reduce greenhouse gas emissions, HDR has recommended adopting liquefied natural gas (LNG) into Hawaiʻi's current energy portfolio and converting natural gas (NG) assets to clean ammonia (NH3) and/or hydrogen (H2) in the future.

Fuel Needs for Expected Loads

For Hawaiʻi to achieve its Renewable Portfolio Standards[112], the use of NG must be phased out before 2045 in favor of low-carbon alternative fuels. H2 is one fuel that may be an appropriate replacement for NG, especially in power generation applications. There are substantial efforts to increase the H2 production capacity in the United States through programs like the Department of Energy's Hydrogen Shot, which seeks to reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade.[113] If these programs are successful, the amount of H2 available on the US mainland is expected to greatly increase.

Before utilizing an expanded US and international H2 production market, Hawaiʻi needs to act to ensure grid stability while reducing greenhouse gas emissions. In HDR's proposed final path, the following capacity and generation are either built or converted to NG assets over Phases 1 and 2, see Table 1.

Table 1. Expected Electricity Needs on Oʻahu

Phase	Year	Total Capacity Converted (megawatt [MW])	Total Generation Estimate (terawatt [TWh])
1	2030	424	1.98
2	2035	487	2
	Total	911	3.98

[112] Public Utilities Commission | Hawaii's Renewable Energy and Energy Efficiency Policies

[113] Hydrogen Shot | Department of Energy

Generating the approximately 4,000,000 megawatt-hours (MWh) of electrical energy, as outlined in Table 1 above, using H2 fuel, would require approximately 265,000 metric tons of H2 per year.

For reference, the current US production of H2 is approximately 10 million metric tons per year and the Department of Energy Clean H2 Strategy indicates a potential for this to grow to 50 million metric tons by 2050.[114]

Hydrogen Delivery Pathways

Considering the main intent of H2 use in Hawai'i would be for power generation, on-island production of H2 is likely not feasible. A typical onsite production scenario would include H2 generation from electrolysis, onsite storage of H2 in tanks, and combustion of the H2 for power generation. The typical round-trip efficiency of this process is less than 30%, meaning 3 kilowatt-hours (kWh) of electrical energy input to H2 production is required to produce 1 kWh from combusted H2. Successful deployment of this type of system requires extensive build-out of renewable electricity generation assets like wind and solar. Installation of renewable assets at this scale would likely exceed land availability constraints on the islands.

To meet H2 demands of over 265,000 metric tons per year, Hawai'i will likely need to consider fuel delivery via bulk tanker in a similar configuration to LNG deliveries. The tables below provide comparisons of two developing methods for delivering H2 molecules for fueling purposes. These are compared to LNG delivery to demonstrate the scale associated with each pathway. In general, the two pathways are:

1. **Liquid Hydrogen –** Gaseous H2 fuel is cryogenically cooled below its boiling point. Liquefying the gas increases the volumetric energy density, which makes transporting the fuel more economical. Upon receipt, the liquid H2 must be re-gasified for use with power generation equipment.
2. **Anhydrous Ammonia –** Gaseous H2 is generated via conventional processes. A Haber-Bosch process is then employed to combine H2 with nitrogen molecules from atmospheric air to synthesize NH3 molecules. NH3 can then be transported in a liquid form with high density. Upon receipt, NH3 must be thermally cracked to release combustion-ready H2.[115]

There are many design differences for infrastructure in terms of LNG, NG, NH3, and H2. Table 2 below shows the property difference between the fuels.

Table 2. Fuel Properties

[114] U.S. National Clean Hydrogen Strategy and Roadmap

[115] Note, there are R&D efforts by major turbine manufacturers to directly combust liquid NH3, which would remove the need for cracking.

Fuel	State	Gross Heating Value (Btu/lb)	Net Heating Value (Btu/lb)	Density (lb./ft^3)	Energy Density HHV (Btu/ft^3)	Energy Density LHV (Btu/ft^3)	Boiling Point at 1 atm (°F)	Heat of Vaporization (Btu/lb)
NG (US market)	Gas	22,453	20,267	0.0485	1,089	983	-259 (methane)	N/A
LNG	Liquid	23,734	20,908	26.73	634,496	558,943	-259 (methane)	239
Anhydrous NH3	Liquid	9,551	8,001	42.57	406,586	340,302	-28	593
H2	Gas	61,127	51,682	0.00562	343	290	-423	N/A
H2	Liquid	60,964	51,621	4.42	269,447	228,155	-423	192

A few key takeaways from this comparison of chemical properties shown in Table 2 above include:

- LNG has the highest energy density as a fuel for transportation. NH3 contains roughly 60% of the energy per volume compared to LNG while liquid H2 contains only 40%.
- Current technology for liquefying H2 below the boiling temperature of -423°F is highly energy intensive and the potential for boil-off loss is increased during transit due to the lower storage temperature.
- Anhydrous NH3 has a high boiling temperature compared to LNG and liquid H2, which makes liquefaction more economical. However, the process of converting H2 to NH3 and NH3 back into H2 requires additional energy input (cracking) and reduces the overall efficiency of the fuel transportation.

As shown in Table 3 below, receiving bulk liquid H2 deliveries via ship at the scale needed to provide the expected power generation demands would result in a large increase in the number of deliveries required. Since shipments from the mainland to Hawaiʻi may take weeks, this method of H2 delivery also incurs significant losses from boil-off gas, which is significantly increased by the low storage temperature of the cryogenic liquid H2.

Table 3. Delivery Pathway Summary

Description	Units	LNG	LH2	NH3
Energy Delivered	Million British Thermal Unit (MMBTU) per year	28,238,900	28,238,900	28,239,900
Gallons Required	Gallons per year	328,500,000	925,357,000	721,794,000

Tankers Required	Ships per year[116]	4-6	12-14	9-11
Transport Temp	Fahrenheit [°F]	-259	-423	-28
Boil-off Loss	% per day	0.1%-0.25%[117]	2%-2.5%[118]	0.015% to 0.03%[119]

Additionally, the commercial availability of liquid H2 transport via ship is relatively underdeveloped in the current market; whereas NH3 is commonly transported in support of the fertilizer industry.

For these reasons, HDR considered anhydrous NH3 to be a more appropriate pathway for transporting H2 molecules to Hawaiʻi to meet the proposed renewable power generation requirements.

Proposed Ammonia Concept

In general, delivery of NH3 for conversion to gaseous H2 fuel will involve a significantly different set of processes as compared to the receipt of LNG. The diagram below loosely demonstrates the process needed.

Figure 1. Process for Ammonia Use as an Energy Carrier

Receive NH3 Shipment → **Unload and Store** → **Thermally Crack NH3 to H2** → **Store Gaseous H2** → **Transport to End Use**

To date, the concept of receiving bulk NH3 delivery as an energy carrier for the import of green H2 has not been implemented. However, this concept has been proposed and evaluated by multiple entities throughout the world. Below are a few examples of proposed projects that intend to use this method for green H2 energy import:

- Germany floating NH3 import terminal[120].
- Port of Rotterdam NH3 terminal[121].

[116] Approximately 70,000 [GAL] per ship

[117] ON THE BOIL OFF RATE OF LIQUEFIED CARGO OF GAS CARRIER DURING A PARTIALLY LOADED VOYAGE (trb.org)

[118] A comparative study on energy efficiency of the maritime supply chains for liquefied hydrogen, ammonia, methanol and natural gas - ScienceDirect

[119] Ammonia as fuel for ships | Bureau Veritas

[120] First Floating Import Terminal with a Hydrogen Cracker Planned for Germany

[121] Large-scale ammonia cracker to enable 1 million tonnes of hydrogen imports via port of Rotterdam | Port of Rotterdam

- Daeson, South Korea NH3 import[122].

While the full NH3-H2 supply chain described above has not yet been implemented, the key processes required to transport NH3 and to decompose it into H2 are commercially available and implemented in other industries. Anhydrous NH3 is frequently shipped as feedstock to the fertilizer industry. Both land and sea-based infrastructure exists and is available.

Multiple vendors exist with commercial offerings for thermal NH3 cracking plants. A few of these include KBR, Topsoe, Thyssenkrupp, Johnson Matthey, Duiker, Casale, and H2Site.

Additionally, large-scale NH3 cracking facilities like the size needed to meet the expected H2 demands are currently in operation. One example of this is a facility provided by Topsoe in Arroyito, Argentina. While not specifically aimed at the production of H2 fuel, this facility does demonstrate a capability to process and crack 4,800 metric tons of NH3 per day, which is comparable to the approximately 3,900 metric tons per day expected to meet Hawaiʻi's energy demands.

Figure 2. Image of Ammonia Processing Facility[123]

Since the use of NH3 as energy carrier is rapidly evolving, potential configuration created at this stage should be considered as a conceptual-level arrangement only.

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[122] KBR to provide cracking tech for new South Korean project - Ammonia Energy Association

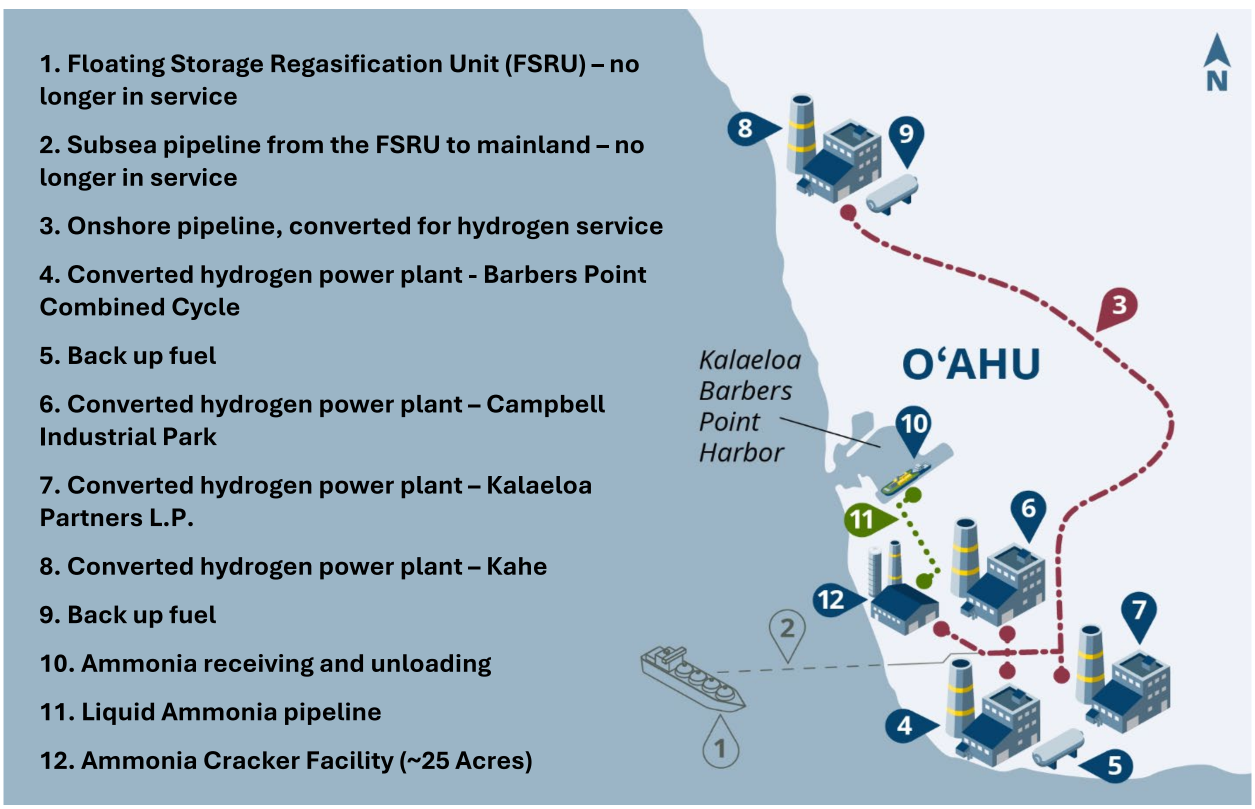
[123] Argentina recupera la Planta Industrial de Agua Pesada de Arroyito

If NH3 were employed as an energy carrier for transporting green H2 to Hawaiʻi at some time in the future, the state of technology at that time would need to be re-evaluated to confirm newly developed best practices are incorporated.[124]

In developing this concept, HDR considered proposed configurations of announced NH3 projects as well as the potential footprint of the NH3 cracking facilities described above. In general, the large throughput of NH3 processing expected to be required seems to favor a land-based NH3 cracking facility. While floating NH3 cracking facilities have been proposed, the throughput of these facilities does not seem to be large enough to accommodate the H2 needs forecasted for Hawaiʻi.

The concept shown in Figure 3 below for the island of Oʻahu would mirror operation of the existing oil refinery. NH3 could be received at the Barber's Point Harber and then transported via pipeline to new NH3 processing equipment. H2 produced by the NH3 cracking could then be transported via pipeline to the adjacent power plants.

Figure 3. Ammonia Energy Concept for Oʻahu



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[124] As of 2024, turbine manufactures GE Vernova, Mitsubishi, and IHI have successfully conducted field tests of combusting liquid NH3 in their turbines. As these turbines improve and if further tests are validated, Hawaiʻi may choose to implement a system that combusts NH3 rather than H2. This would remove the need for the energy intensive cracking process.

LNG Infrastructure Reuse

As described elsewhere, HDR proposes Hawaiʻi adopt LNG as a near-term energy source to bridge the gap between current oil-based power generation and the goal of fully carbon neutral energy use on Oʻahu. The proposed LNG infrastructure is fully described in other HDR Technical Documentation. Since LNG is being considered as an intermediate fueling solution with the long-term goal of utilizing carbon neutral H2, consideration is needed regarding the ability to convert LNG and NG-based infrastructure to the proposed NH3-H2 delivery concept outlined in this document.

In general, the majority of the fuel receiving and processing equipment is not expected to be interchangeable between the two fuels. The proposed LNG receiving method makes use of a floating storage regasification unit (FSRU) for unloading and regasification of LNG. Converting NH3 to H2 for use as a fuel to meet the expected electricity needs will require significant NH3 storage and cracking infrastructure beyond what can be accommodated by a floating vessel. NH3 will need to be received and processed with new land-based infrastructure specifically dedicated to processing this NH3.

While the fuel infrastructure may not be interchangeable, much of the power generation equipment proposed to be fueled by NG supplied as LNG could be installed to provide the capability to operate on H2 in the future. Many of the prominent gas turbine suppliers have published clear plans to transition their generation equipment to operation on H2 as a fuel. Some turbines can be supplied today with full H2 capability but, in general, the market for H2-capable gas turbines is expected to fully develop in the next 10 years.

Converting a natural gas power plant to H2 would require modification of the fuel system to accommodate the large volumetric flows associated with H2, however, most of the steam and power systems within the plant could continue to operate as designed regardless of the fuel used.

Additionally, pipelines installed on the island for the transportation of NG could be converted for the transport of gaseous H2 fuel.

Ammonia Supply

An additional consideration for implementing the proposed NH3-H2-based fueling system outlined in this document is the ability to source bulk low-carbon NH3. Based on US Geological Survey data, the United States produced close to 14 million metric tons of NH3 in 2023[125]. 88% of this NH3 was used for agriculture purposes with the remainder serving other chemical and industrial processes. The majority of this was used within the United States with only 1 million metric tons being exported. This NH3 was produced from 36 different plants throughout the country operating at approximately 90% of rated capacity.

[125] Nitrogen Statistics and Information | U.S. Geological Survey

The current US NH3 production is spoken for and would not be available as fuel supply to Hawai‘i. Additionally, the level of electrical generation proposed is expected to require 1.5 million metric tons of NH3 per year, which is 11% of the 2023 nationwide production. NH3 production in the United States would need to be significantly increased to meet this demand.

Recently, multiple announcements have been made indicating the potential expansion of the US NH3 generation capabilities. Most of these projects are aimed at providing low-carbon NH3 as a fuel source. A few of these are noted below. Development of these projects and other low-carbon NH3 production facilities should be carefully evaluated before committing to an NH3-H2 energy supply strategy for Hawai‘i.

- Ascension Clean Energy - Louisiana[126]
- CF Industries Blue Point Complex - Louisiana[127]
- SIP St Charles Project - Louisiana[128]
- Adams Fork Clean Energy – West Virginia[129]
- Gulf Coast Ammonia - Texas[130]
- Nutrien - Louisiana[131]

Outside of the United States, NH3 for fuel markets in Australia and Southeast Asia should also be considered as Hawai‘i looks to make the fuel transition.

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126 The Ace Project

127 CF Industries and JERA Announce JDA to Develop Greenfield Low-Carbon Ammonia Production Capacity in U.S. | CF Industries

128 St. Charles

129 AdamsForkEnergy

130 Gulf Coast Ammonia – Meeting domestic & global demands for agricultural fertilizers

131 Nutrien Announces Intention to Build World’s Largest Clean Ammonia Production Facility | Nutrien

Appendix H - Anticipated Permits and Approvals

The tables below include the anticipated permits that may be applicable.

- Table 15 includes the Federal permits and approvals
- Table 16 includes the State permits and approvals
- Table 17 includes the Oʻahu permits and approvals

Table 15. Federal Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
National Historic Preservation Act (NHPA) Section 106 Review and Compliance	Advisory Council on Historic Preservation / State Historic Preservation Division	D	Will the project require federal assistance, including federal funding, permits, or approvals, and have the potential to affect historic properties?
National Environmental Policy Act (NEPA)	Council on Environmental Quality, Lead Agency Depends on Federal Action	D	Will the project require a federal action (including federal funding, permits, or approvals) or be located on federal land triggering the National Environmental Policy Act (NEPA)?
Department of Defense Consultation	Department of Defense	D	Will the project have potential to affect Department of Defense (DOD) installations or training activities in Hawaiʻi?
Marine Mammal Protection Act (MMPA) Incidental Harassment Authorization or Letter of Authorization	National Oceanic and Atmospheric Administration, National Marine Fisheries Service	D	Will the project have potential to affect marine mammals protected by the Marine Mammal Protection Act (MMPA)?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Essential Fish Habitat Consultation, Magnuson-Stevens Fishery Conservation and Management Act (MSA)	National Oceanic and Atmospheric Administration, National Marine Fisheries Service	D	Will the project require federal funds, permit, or activities that may adversely affect essential fish habitats (EFH) under the Magnuson-Stevens Fishery Conservation and Management Act (MSA)?
Endangered Species Act (ESA) Section 7 Consultation and Compliance (National Oceanic and Atmospheric Administration [NOAA], U.S. Fish and Wildlife Service [USFWS]) Incidental Take Permit, Section 10 (NOAA, USFWS)	National Oceanic and Atmospheric Administration, National Marine Fisheries Service, US Fish and Wildlife Service, Pacific Islands Fish and Wildlife Field Office	D	Will the project have potential to incidentally or unintentionally harm threatened or endangered species or designated critical habitats listed under the Endangered Species Act (ESA)?
Clean Water Act (CWA) Section 404 Permit (Department of Army Permit, Individual or Nationwide Permit)	US Army Corps of Engineers (USACE), Regulatory Branch	D	Will the project require any work in, under, or over Waters of the United States or the discharge (e.g., dump, place, deposit) of dredged or fill material in Waters of the United States (including navigable waters and wetlands)?
Marine and Harbor Activities Notice	US Coast Guard, Department of Homeland Security	M	Will the project require activities within navigable Waters of the United States that may affect marine vessel or harbor activities?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Spill Prevention, Control, and Countermeasure (SPCC) Plan	US Environmental Protection Agency	M	Will the project include bulk above ground storage tanks with a total oil capacity of over 1,320 gallons in containers of 55 gallons or larger or total buried storage capacity over 42,000 gallons?
Deepwater Ports	Maritime Administration	D	A licensing system for ownership, construction, operation, and decommissioning of deepwater port structures located beyond the U.S. territorial sea for the import and export of oil and natural gas
Authorization for Liquefied Natural Gas Terminal Facilities, Onshore or in State Waters	FERC	D	Application for the siting, construction, expansion, or operation of an LNG terminal filed pursuant to section 3 of the Natural Gas Act
Section 10 of the Rivers and Harbors Act of 1899	USACE	D	Placement of structures affecting course, location, condition, or capacity of navigable waters of U.S. (includes offshore wind within 3 miles of coast); exemptions exist)
USCG Letter of Recommendation for Marine Operations	USCG	D	An owner or operator seeking approval from FERC to build and operate or expand an LNG facility, as defined in 33 CFR Part 127

* Permit Type is defined as 1) D = Discretionary or 2) M = Ministerial

Table 16. State Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Hawaiʻi State Environmental Policy Act (HEPA)	Office of Planning and Sustainable Development, Environmental Review Program	D	Will the project require a state action (including federal funding, permits, or approvals) or be located on federal land triggering the National Environmental Policy Act (NEPA)?
Lease, Easement, or Right-of-Entry	Department of Hawaiian Home Lands, Hawaiian Homes Commission	M	Will the project use lands owned, managed, or controlled by the Department of Hawaiian Home Lands (DHHL)?
Air Pollution Control Permit, Covered Source Permit or Noncovered Source Permit	Department of Health, Clean Air Branch	M	Will the project construct, reconstruct, modify, or operate a stationary air pollution source?
National Pollutant Discharge Elimination System Permit (Individual and General Construction Activities)	Department of Health, Clean Water Branch	M	Will the project disturb one or more acres of land?
National Pollutant Discharge Elimination System Permit (Dewatering Permit)	Department of Health, Clean Water Branch	M	Will project's construction require the removal or temporary relocation of groundwater or surface water from the site?
National Pollutant Discharge Elimination System Permit (Individual and General Industrial Activities)	Department of Health, Clean Water Branch	M	Will the project be considered an industrial facility that is regulated under HAR Section 11-55, Appendix B?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Section 401 Water Quality Certification	Department of Health, Clean Water Branch	M	Is there potential for the project to discharge pollutants into waters of the State and/or require a Section 404 Individual Permit?
Community Noise Permit / Noise Variance	Department of Health, Indoor and Radiological Health Branch	M	Will the project conduct any construction activity or install stationary equipment that will exceed the maximum allowable noise limits set by HAR Section 11-46-3?
Comprehensive Environmental Response, Compensation, and Liability Act Compliance	Department of Health, Office of Hazard Evaluation and Emergency Response (delegated by US Environmental Protection Agency	M	Does the project site contain confirmed or potential soil contaminated by hazardous waste or materials?
Hazardous Waste Treatment, Storage, and Disposal Permit Hazardous Materials Permit (FHAZ)	Department of Health, Solid and Hazardous Waste Branch	M	Will the project require the storage, disposal, or treatment of any hazardous waste that meets the definition of hazardous waste under HAR Section 11-261.1?
Elevator and Kindred Equipment Permit	Department of Labor and Industrial Relations, Hawaiʻi Occupational Safety and Health	M	Will the project install or alter elevators, dumbwaiters, escalators, moving walks, stage lifts, personnel hoists, or other mechanized equipment to convey people in place?
Incidental Take License and Habitat Conservation Plan	Department of Land and Natural Resources, Division of Forestry and Wildlife, Wildlife Section	D	Will the project "take" a Hawaiʻi-listed threatened or endangered species?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Submerged Land Lease	Department of Land and Natural Resources, Land Division	D	Will the project require a lease for an area within the state marine waters or submerged lands?
Lease, Easement, or Right-of-Entry	Department of Land and Natural Resources, Land Division	D	Will the project require one or more of the following: access, use, or other easements to public lands; the purchase of remnant public lands; direct land lease; and/or a land license?
Historic Preservation Review and Compliance (HRS 6E)	Department of Land and Natural Resources, State Historic Preservation Division	D	Will the project affect cultural, archeological, or historic resources or sites or require state approvals or funding?
Ocean Waters of the State Work Permit	Department of Transportation, Harbors Division	M	Will the project perform any dredging, filling, installation of buoys, or erection of any construction within commercial harbors or entrance channels belonging to or controlled by the state?
Permit for the Occupancy and Use of State Highway Right-of-Way	Department of Transportation, Highways Division	M	Will the project require equipment or infrastructure located within the state highway right-of-way?
Coastal Zone Management Federal Consistency Certification	Office of Planning and Sustainable Development	M	Will the project involve a federal agency action (such as needing to obtain a federal permit, receive federal funding, or be constructed on federal land) and affect any coastal use or resource?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Certificate of Public Convenience and Necessity	Public Utilities Commission	D	Will the project provide, sell, or transmit power directly to the public or end users other than a public utility?
Power Purchase Agreement or Fuel Purchase Agreement	Public Utilities Commission	D	Will the project sell power, fuel, or gas to one of Hawaiʻi's regulated public utilities (KIUC, HECO, MECO, HELCO, or Hawaiʻi Gas)?
Transmission Line Approval	Public Utilities Commission	D	Will the project interconnect to the existing electric grid and require a new transmission line?

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Table 17. Oʻahu Permits and Approvals

Permit / Approval	Agency	Permit Type	Regulatory Trigger
State Special Use Permit (Oʻahu)	Department of Planning and Permitting, Planning Division	D	Will the project require non-permissible uses (i.e., "unusual and reasonable" uses) within the agricultural and/or rural land use districts? Only required for parcels located in the State Agricultural District.
Conditional Use Permit (CUP) (Major or Minor) (Oʻahu)	Department of Planning and Permitting, Planning Division	D	Will the project conform to the land uses permitted in the parcel's county zoning designation?
Shoreline Setback Variance	Department of Planning and Permitting	D	Will the project include structures, facilities, construction, or any activities prohibited within the shoreline setback area?
Minor Shoreline Structure Permit	Department of Planning and Permitting	D	Will the project include minor structures within the shoreline setback area?
Special Management Area Assessment (Oʻahu)	Department of Planning and Permitting (DPP), Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA)?
Special Management Area Use Permit Major (Oʻahu)	Department of Planning and Permitting, Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA) that will exceed $500,000 (or $125,000 in Maui County) or is expected to have a substantial adverse environmental or ecological effect to coastal areas?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Special Management Area Permit Minor (Oʻahu)	Department of Planning and Permitting, Land Use Permits Division	D	Will the project require development on land or in/under water within a Special Management Area (SMA) that does not exceed $500,000 (or $125,000 in Maui County) and which has no substantial adverse environmental or ecological impact on coastal areas?
Flood Determination Approval + Flood Hazard District Variance (Oʻahu)	Department of Planning and Permitting, Building Division	M	Will the project be located in a flood zone?
Building Permit	Department of Planning and Permitting, Building Division	M	Will the project construct, alter, move, demolish, repair, or use any building or structure or require electrical or plumbing work?
Tank Installation Permit	Honolulu Fire Department	M	Will the project install or operate equipment in connection with the storage, handling, use, or sale of flammable or combustible liquids regulated under Chapter 66 of the National Fire Protection Association?
Sewer Connection Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require a connection to the county wastewater system?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Grading Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require excavation or filling with earth materials (e.g., rock, coral, gravel, soil, recycled asphalt pavement) that are taller than 3 feet high or greater than 50 cubic yards in volume, or redirect existing surface run-off patterns with respect to adjacent properties?
Grubbing Permit	Department of Planning and Permitting, Site Development Division	M	Will the project uproot or dislodge vegetation from the ground surface across an area larger than 15,000 square feet?
Stockpiling Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project require the temporary open storage of earth materials in excess of 100 cubic yards?
Trenching Permit (Oʻahu)	Department of Planning and Permitting, Site Development Division	M	Will the project trench (i.e., dig, break, disturb, or undermine) any public highway, street, thoroughfare, alley, or sidewalk or any other similar public space?
Erosion and Sediment Control Plans for Small Construction Projects	Department of Planning and Permitting	M	Is the project a residential or commercial project less than 1 acre in size within the City and County of Honolulu (CCH) that requires a Building Permit, but does not require a Grading, Grubbing, or Stockpiling permit?
Construction Dewatering Permit	Department of Planning and Permitting	M	Will the water from the construction site discharge into the city-owned municipal storm sewer system?

Permit / Approval	Agency	Permit Type	Regulatory Trigger
Industrial Wastewater Discharge Permit (IWDP)	Department of Planning and Permitting, Site Development Division, Wastewater Branch	M	Will the project require a building permit and have a sewer connection for the discharge of water into the county sanitary sewer?
Storm Drain Connection License	Department of Planning and Permitting, Site Development Division	M	Will the proposed project require a private drainage-system connection to the city municipal separate storm sewer system (MS4)?
Driveway Variance	Department of Planning and Permitting, Site Development Division	M	Will the project require a driveway approach that deviates from City and County of Hawaiʻi (CCH) standards?
Sign Permit	Department of Planning and Permitting, Site Development Division	M	Will the project require the installation or modification of any fixed, permanent signs?
Authorization of Surface Encroachment	Department of Planning and Permitting, Site Development Division	M	Will the project require placement of landscaping, objects, or structures on city sidewalk areas that deviate from city standards?
Demolition Permit	Department of Planning and Permitting, Site Development Division	M	Will the project require demolition of any building?

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