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THE ECONOMIC RESEARCH ORGANIZATION
AT THE UNIVERSITY OF HAWAII

**AN ECONOMIC AND GHG ANALYSIS
OF LNG IN HAWAII**

BY

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An Economic and GHG Analysis of LNG in Hawaii

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List of Acronyms

AEO	Annual Energy Outlook
CAP	capital costs
CO ₂	carbon dioxide
CAA	Clean Air Act
CWA	Clean Water Act
CC	combined cycle
CCGT	combined cycle gas turbine
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CPI	Consumer Price Index
DES	delivered-ex-ship
DOH	Department of Health
EGU	electric generating unit
EPCRA	Emergency Planning and Community Right-to-Know Act
EPAct	Energy Policy Act of 2005
E&P	exploration and production
FERC	Federal Energy Regulatory Commission
FOM	fixed operating and maintenance
FSRU	floating storage regasification unit
FTA	Free Trade Agreement
FOB	freight on board
GT	gas turbine
GAMS	General Algebraic Modeling System
Geo	geothermal
GWh	gigawatt hour
GHG	greenhouse gas
KBPH	Kalaheo Barber's Point Harbor
H-CGE	Hawaii Computable General Equilibrium Model
HELM	Hawaii Electric Model
IPCC	Intergovernmental Panel on Climate Change
IFO	intermediate fuel oil
IRP	Integrated Resource Plan
JCC	Japan Customs-Cleared Crude, or Japanese Crude Cocktail
JKM	Japan Korea Marker
LSFO	low sulfur fuel oil
MACT	Maximum Achievable Control Technology
MWh	megawatthour
CH ₄	methane
MATS	Mercury Air Toxic Standards
MT	metric tons
MMT	million metric tons
MMBtu	million British thermal units
MSW	municipal solid waste
NAAQS	National Ambient Air Quality Standards
NBP	National Balancing Point
NEHAPS	National Emissions Standards for Hazardous Air Pollutants
NEPA	National Environmental Policy Act
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
RPS	Renewable Portfolio Standard
RCRA	Resource Conservation and Recovery Act
Rooftop	Rooftop photovoltaic

SDWA	Safe Drinking Water Act
STS	ship-to-ship
SC	simple cycle
SCGT	simple cycle gas turbine
SIC	Standard Industrial Classification
ST	steam turbine
GREET	The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
TSCA	Toxic Substances Control Act
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
PV	utility scale photovoltaic (unless otherwise specified)
PVbatt	utility scale photovoltaic with battery storage
VOM	variable operating and maintenance
Windbatt	wind with battery storage

Executive Summary

Hawaii currently meets the majority of its electricity needs through costly oil-fired generation causing rates to be nearly four times the national average (EIA, 2013a). The “shale gas revolution” has led to rapidly declining natural gas prices within the continental U.S. The emergence of a natural gas market that is de-linked from oil prices has renewed Hawaii’s interest in natural gas imports. Potentially lower natural gas prices as well as the view that it will help to reduce greenhouse gas (GHG) emissions and increase energy supply security through domestic sourcing are major reasons why the State and key stakeholders are deliberating over importing large amounts of natural gas in liquefied form (liquefied natural gas or LNG). This study uses detailed models of Hawaii’s electric sector and overall economy to estimate the impacts of Hawaii importing LNG for use in the electric sector.

Motivations and Uncertainties

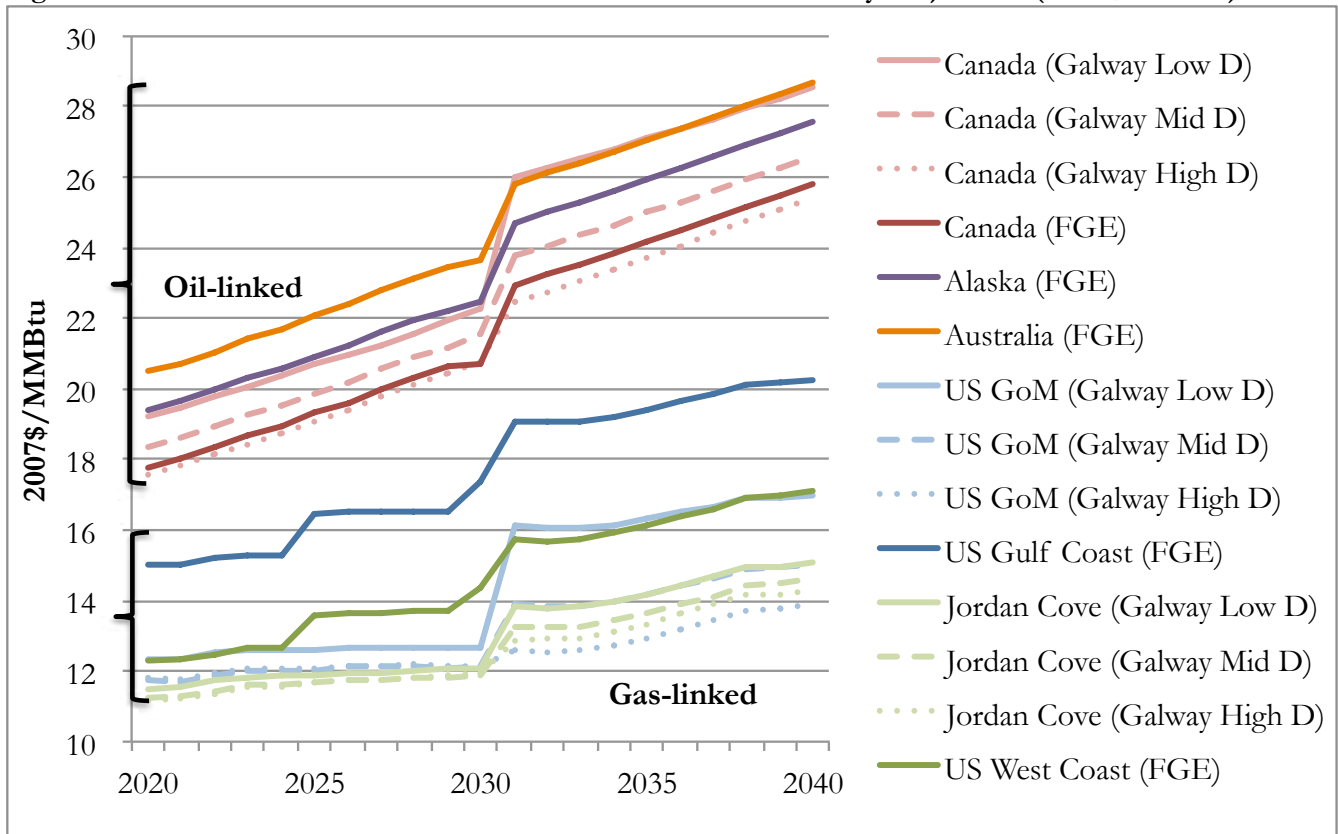
The Hawaii Clean Energy Initiative and the State’s goal to return Hawaii’s GHG emissions to 1990 levels by the year 2020 (excluding aviation) could provide additional motivation for the adoption of natural gas. Natural gas is often characterized as a “bridging fuel” in the transition to renewable energy systems because when coupled with grid modernization efforts, natural gas-fired generation provides better support for intermittent sources of renewable energy than either oil or coal-fired generation. Opponents of using natural gas as a bridging fuel, however, argue that bringing down fossil fuel prices will only make it harder for renewable sources of energy to compete. In addition, natural gas may not have fewer GHG emissions than other fossil fuels when considering the full lifecycle GHG impact. This accounting is subject to a wide range of uncertainty depending on how natural gas is procured and transported as well as the study methodology.

From a regulatory standpoint, using natural gas within the electric sector may also help in compliance with Hawaii’s near-term U.S. Environmental Protection Agency (EPA), Clean Air Act requirements in regards to Mercury and Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS). MATS becomes effective in 2015 and NAAQS, in 2022. Nonetheless, ongoing studies (currently by the EPA) in regards to the impact of hydraulic fracturing to nearby water resources have led to controversy on whether natural gas can appropriately be considered a source of “clean” energy.

Building on Prior Work

There have been several studies addressing the viability of importing and using LNG in Hawaii. We draw upon two recent studies, by Facts Global Energy (2012) and Galway Energy Advisors (2013) for price estimates. The first report was commissioned by the Hawaii Natural Energy Institute (HNEI), and the second was submitted as an appendix in the recent Integrated Resource Plan of the Hawaiian Electric Companies. We synthesize and harmonize the price projections of prior studies to better understand the potential range of LNG prices that Hawaii may experience. The normalized price projections are shown below in Figure ES-1.

Figure ES-1. Normalized Delivered Gas Prices to Hawaii – Prior Study Projections (2007\$/MMBtu)



Methods and Scenarios

Using a range of three price projections – Australia (FGE) for *High*, U.S. GoM (Galway MidD) for *Low*, and the average of the two as *Medium*, we use models of Hawaii’s electric sector and its macro-economy to estimate impacts such as electric sector costs, technology profile, and GHG emissions (lifecycle and out-of-stack); as well as gross state product, household income, and sector output. We use UHERO’s Hawaii Electric Sector Model (HELM) and the Hawaii Computable General Equilibrium Model (H-CGE). HELM is calibrated to all existing generation units within the State and solves for the least-cost way to meet electricity demand, by technology and for each county, from the year 2015 to the year 2040. H-CGE is an economy-wide model calibrated to a Social Accounting Matrix for the State economy based on the Department of Business, Economic Development and Tourism’s most up-to-date Input-Output Table. It also projects to the year 2040. Baseline economic activity is impacted by changes in the world price of oil, as estimated by the U.S. Energy Information Agency’s Annual Energy Outlook (AEO) 2013 *Reference* forecast (for Brent crude).

We look at four main scenarios: 1) Baseline: where there is no gas introduced in Hawaii; 2) Low Gas Price: where natural gas follows a “low” price trajectory (U.S. GoM, Galway MidD); 3) Medium Gas Price; and 4) High Gas Price (Australia, FGE). For the core scenarios, we assume that the State’s Renewable Portfolio Standard (RPS) requiring that 40% of electricity sales be from renewable sources by the year 2030 is met. We relax this assumption for sensitivity analysis.

Key Findings

We find that natural gas use in Hawaii can be economically attractive even considering the up-front capital investment needed to for building the infrastructure necessary to import and distribute natural gas. While natural gas could help in meeting Federal and State environmental regulations, there are likely negative environmental impacts outside of Hawaii. This includes upstream GHG emissions (estimated as part of this study) as well as potential effects of hydraulic fracturing on water resources.

Introducing natural gas could reduce electric costs substantially – by up to 25% (in 2040) when natural gas prices are Low (i.e. based on gas-linked prices). When natural gas prices are High (or oil-linked), electric sector costs are estimated to decrease by a modest 6% (in 2040). Table ES-1 summarizes our findings on electric sector costs from the three gas price scenarios relative to the baseline.

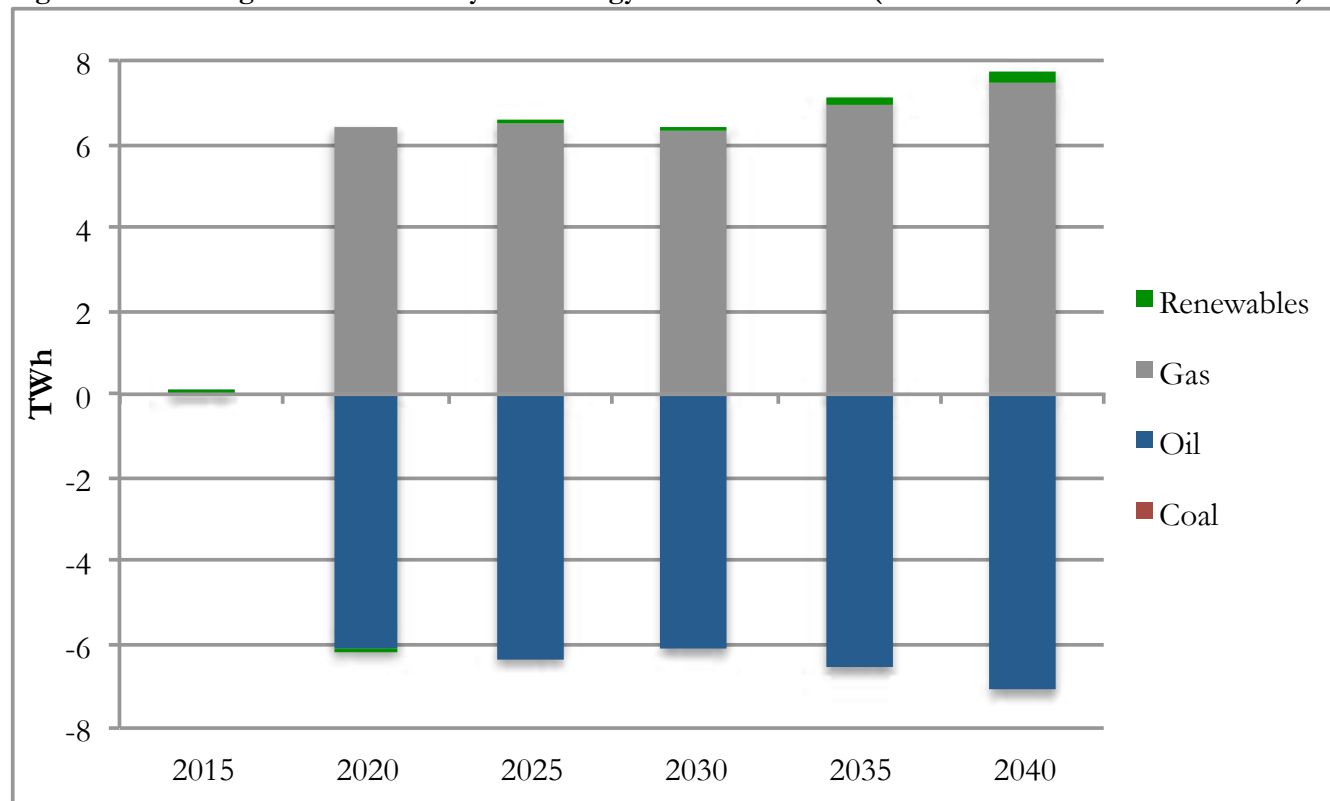
Table ES-1. Baseline Electric Sector Costs and Change in Costs from the Baseline

	2015	2020	20.25	2030	2035	2040
Baseline (\$ Billion)	12.2	13.8	11.4	12.6	14.8	15.9
	<i>Change from Baseline (%)</i>					
Low	0%	-24%	-10%	-14%	-20%	-25%
Med	0%	-19%	-3%	-6%	-9%	-14%
High	0%	-2%	-2%	-4%	-2%	-6%
	<i>Change from Baseline (\$ Billion)</i>					
Low	0.0	-3.3	-1.2	-1.8	-2.9	-3.9
Med	0.0	-2.6	-0.4	-0.8	-1.3	-2.2
High	0.0	-0.3	-0.2	-0.5	-0.3	-0.9

In the case that natural gas prices are Low, we find that electric sector costs could be reduced by nearly \$4 billion in the period 2036-2040. For illustration, if consumer electricity rates are \$0.34/kWh, which is close to today’s prices, then a 25% reduction leads to a reduction in electricity rates of about \$0.05/kWh, or a lowering of rates to \$0.29/kWh. The magnitude of savings clearly varies widely, fuel price being the largest determinant. If the price of natural gas is oil-linked, as in the High scenario, the savings is only \$0.01/kWh. If Hawaii cannot negotiate a gas-linked price, the higher oil-linked gas prices will severely erode any cost savings.

We find that natural gas serves to largely displace oil use within the electric sector (see Figure ES-2).

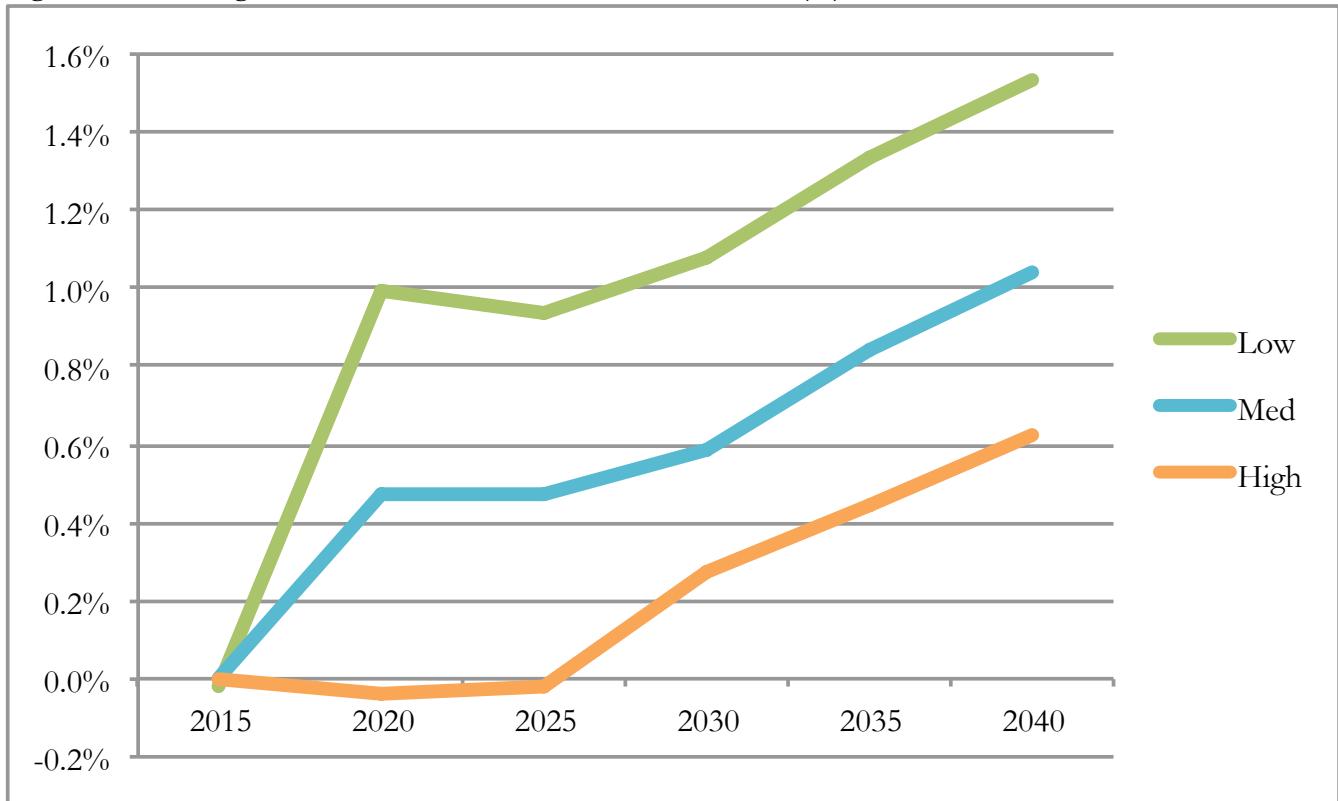
Figure ES-2. Change in Generation by Technology from the Baseline (Medium Natural Gas Price: TWh)



In the Low and Medium cases, it is cost effective to make this switch rather abruptly by the year 2020. In the High price scenario, however, natural gas should be phased in more slowly.

We find that these cost savings translate to increases in real gross state product, as shown in Figure ES-3 below.

Figure ES-3. Change in Real Gross State Product from Baseline (%)

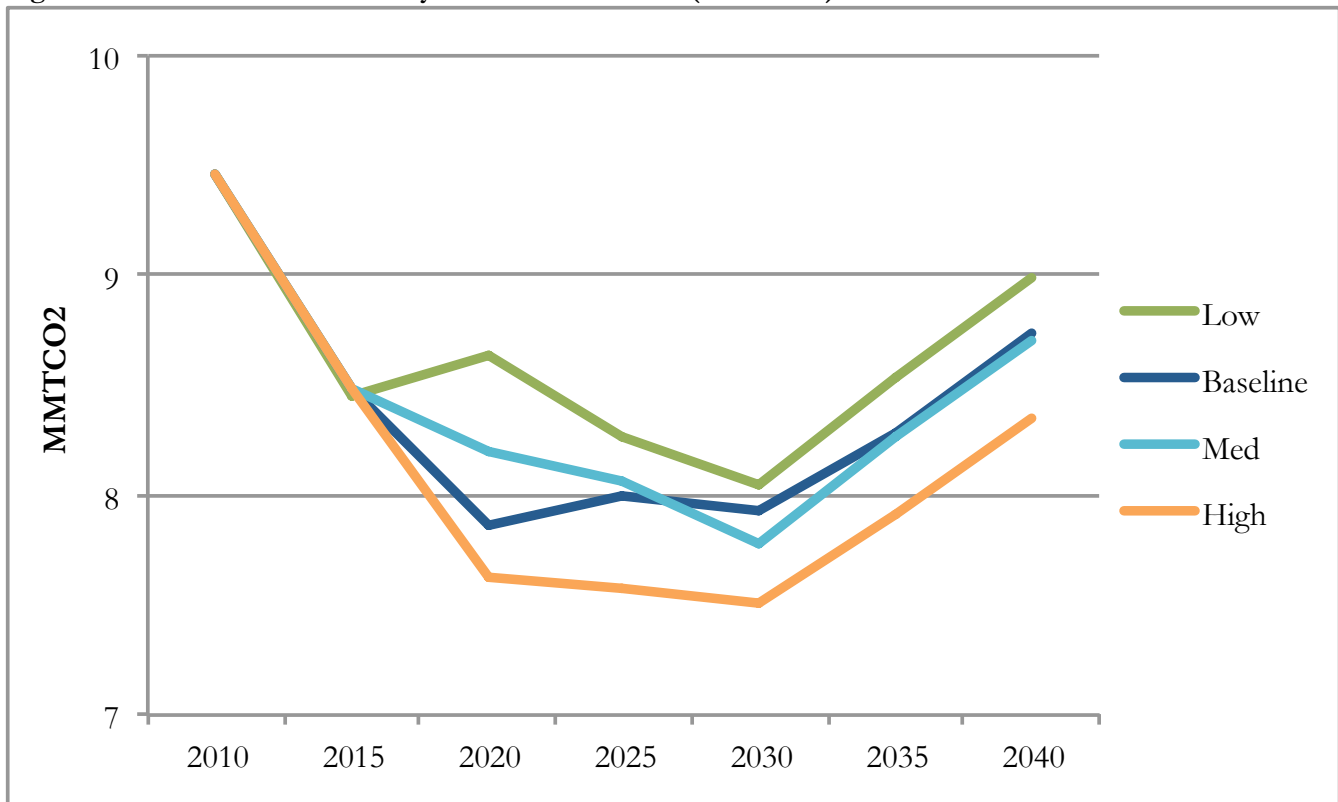


Given the small size of the electric sector relative to overall economic activity, this is a sizeable impact to the economy. Moreover, this impact is cumulative through the entire time period. Over the model horizon, the increase in GSP from the baseline when gas prices are Low has a net present value of \$11 billion (assuming a 4% rate of discount and \$2014). When gas prices are Medium, \$6.2 billion; and High, \$1.8 billion.

As a result of lower electricity rates, household income is “freed up” for expenditures on other goods and services. We find that the average household is able to increase the value of their consumption by a range of \$1,100 to \$1,700 per year by the year 2040. On average from 2020 to 2040, the representative household increases real consumption by \$1,000 annually when natural gas prices are Low, \$840 when they are Medium, and \$570 when they are High.

On the other hand, we find that introducing natural gas increases overall GHG emissions, except in the High price case. Lifecycle emissions (as estimated by the Argonne National Laboratory GREET Model, including estimates for regasification and liquefaction from the DOE) impacts are shown in Figure ES-4.

Figure ES-4. Electric Sector Lifecycle GHG Emissions (MMTCO₂)



If considering only out-of-stack emissions (as required by the State of Hawaii’s GHG emission reduction rules for the electric sector), then introducing natural gas lowers electric sector emissions in all cases. The State’s law requiring emissions reduction (Act 234), however, urges the minimization of “leakage” or the export of emissions from Hawaii elsewhere. In addition, we find that the cost savings incurred by the introduction of natural gas also leads to a rebound effect where there is a relative 8% increase in electricity demand in the Low price case by 2040.

Summary

We find that Hawaii importing natural gas to be used in the power sector could lower costs of electric generation and benefit Hawaii’s economy. Though this finding generally holds through the entire range of LNG prices considered, it is particularly impactful when prices range between the Medium and Low price estimates (i.e. are closer to gas than oil prices). When prices are High, there is a near-term negative impact on gross state product due to the cost of capital relative to the return on the investment.

In the Low and Medium cases there is a dramatic shift away from oil and immediate adoption of gas in the year 2020. In the High case, we find that gas should be phased in much more gradually. In all cases, however, petroleum manufacturing output declines by approximately 30% by the year 2040. Using natural gas in the electric sector serves to drive down out-of-stack GHG emissions in Hawaii but can also lead to higher levels of GHG emissions overall. There are also potential impacts to local water resources and this is being further investigated by the EPA.

We additionally find that if the State’s RPS remains in force, introducing LNG does not serve to displace sources of renewable energy within Hawaii, as currently priced. On the other hand, if the State’s RPS is relaxed, we estimate that importing LNG can reduce the amount of renewable energy adopted within the market. Particularly when natural gas prices are Low, it crowds out solar PV. If solar PV prices continue to decline, however, this finding may not hold. We also find that when natural gas prices are Low, coal-burning could also be displaced. This suggests that LNG is unlikely to serve as a “bridge fuel” unless policies protecting renewable energy adoption are enacted and/or enforced.

Study Limitations

This study has several major limitations in terms of assumptions and scope. This study does not provide a full analysis of alternative investments that could be made in the electric sector to meet future demand. Also we must make assumptions about the relative prices of technologies over time – where we have chosen to assume that oil prices increase and prices of renewable energy remain constant, meaning that renewable sources of energy become more favorably priced. Lastly, this study does not address issues of risk and timing in investing in infrastructure relative to the procurement of fuel.

1. Introduction

The State of Hawaii meets the majority of its electricity needs through oil-fired generation. Electricity rates in Hawaii are the highest in the country and nearly four times the national average (EIA, 2013a). In response to rising oil prices, the State of Hawaii is aggressively pursuing alternative sources of energy for its electric sector. In 2009, the State adopted a Renewable Portfolio Standard (RPS) that mandates Hawaii utilities to meet 40% of their electricity sales with renewable sources of energy by the year 2030. Hawaii now has 690 MW of installed renewable energy capacity, comprising 26% of total demand (when accounting for the average capacity factor for each resource). The portfolio includes 38 MW of geothermal, 31 MW of hydropower, 202 MW of wind, 315 MW of solar (residential, commercial, and utility-scale) and 104 MW of bioenergy (DBEDT, 2014a; EIA, 2013b). Forty-two additional renewable energy projects are in the planning stage (DBEDT, 2014b). While there has been great progress in adopting renewable energy, there is still much work to be done to meet the RPS goal. Moreover, there is concern over the remaining 60% of electricity sales that will still be met through fossil fuels. Lower natural gas prices as well as a perception that it will help to reduce greenhouse gas (GHG) emissions and increase security through domestic sourcing (see, for example the Governor's 2013 State of State Address), is in part why the State and key stakeholders are deliberating importing large amounts of liquefied natural gas (LNG) for use in the electric sector.

Local energy utilities including the Hawaiian Electric Company (HECO) and Hawaii Gas, along with the State's Energy Office, have proposed that integrating LNG into the state's energy supply mix is a practicable option for Hawaii to turn to while renewable energy and grid modernization technologies continue to be developed (Hawaiian Electric Companies, 2014a; Shimogawa, 2014a; Yonan, 2014). This stems from a more general view that natural gas serves as a "bridging" or "transition" fuel for the changeover to renewable energy systems. Opponents of this view argue that using low cost fossil fuels only make it harder for renewable energy to compete and thus slows down the transition to renewable energy (Star Advertiser, 2012). Natural gas is also widely touted as a "clean energy" source, as it produces fewer GHG emissions when undergoing endpoint combustion compared to oil and coal. However, emissions from LNG are less favorable when viewed on a lifecycle basis (i.e. cradle-to-grave). There is great variation in accounting, however, depending on whether the natural gas is sourced conventionally or unconventionally (see Section 4). Understanding the GHG emissions impact of bringing natural gas to Hawaii is important because of Act 234, which requires statewide GHG emissions be reduced to 1990 levels or below (excluding aviation emissions) by January 1, 2020. Administrative rules are in place to ensure monitoring and compliance for large emitters within the electric sector. Although natural gas tends to burn relatively cleanly, the Act also urges the minimization of "leakage," which would push emissions from one location to another.

There have been several studies addressing the viability of LNG use in Hawaii. Earlier studies conducted by Facts Global Energy (2004, 2007) concluded that high fuel and infrastructure cost did not support recommending LNG imports to Hawaii. Following the "shale gas revolution," mainly due to the development of hydraulic fracturing, two more studies have more favorable findings in regards to importing LNG. The first was commissioned by Hawaii Natural Energy Institute and prepared by Facts Global Energy (2012), and the second, was submitted by Galway Energy Advisors (2013) as an appendix in HEP's Integrated Resource Plan. There is also a more qualitative assessment of importing LNG to Hawaii completed as part of the work of the State of Hawaii Refinery Task Force (ICF, 2013; ICF 2014). This study builds upon these past studies and extends the analysis by assessing both the macroeconomic and electricity sector impacts of using natural gas for generation. This study aims to 1) synthesize prior economic studies of LNG in Hawaii, 2) normalize estimated cost projections to better understand the possible range of LNG import costs and use within the electric sector, 3) summarize the state of knowledge on lifecycle-based GHG emissions from natural gas that is first liquefied then regasified and combusted, 4) explore other environmental considerations and their impact to policy and prices, and 5) use a detailed model of Hawaii's economy and electric sector to estimate impacts of LNG imports to the state economy, including GHG emissions.

The study is organized as follows. Section 2 reviews factors that affect LNG import costs and arrangements. It provides a high level summary of impacts identified within prior studies. Section 3 presents the normalized LNG price projections estimated within prior studies and used as the primary data input for this work. Section 4 reviews major environmental impacts, namely to GHG emissions and local water resources. Section 5 presents the model, scenarios, and results. Section 6 provides concluding remarks.

2. LNG Import Considerations

2.1 *The Global LNG Market*

Since 2012, there have been considerable changes in the characteristics of the global LNG market. These changes can be attributed to the recent technological advancements in the extraction processes of unconventional natural gas and the consequent growth of the gas industry. In particular, the rise of North American shale gas production has displaced LNG imports to the continental U.S. Now many of the terminals that once received imported gas are converting into export centers. The U.S. is poised to be a leading global exporter of LNG in the coming years (Galway, 2013).

Traditionally, LNG markets have functioned on smaller regional levels with point-to-point deliveries and stable long-term contracts ranging from 20 to 30 years on average. LNG contracts have historically tended to be long-term since they often finance the infrastructure that is required for the production of LNG. There is still no global price linkage for long-term trade (Galway, 2013; FGE, 2012).

Short-term and spot trade are, however, becoming larger portions of the market; recently accounting for 20% of LNG volume traded worldwide (Galway, 2013). Short-term and spot trade, is characterized by trade in flexible volumes that are divertible and not bound to specific destinations. More purchasers and suppliers means that markets are becoming yet more liquid. Short-term trade is defined by a range of 90 day to up to 2-year terms. In spot markets, suppliers profit through arbitrage opportunities. Globally, LNG pricing is largely determined by the cost of alternative fuels and the netback price for suppliers (Galway, 2013). Since there is no world LNG price, costs deviate greatly between regions. In 2011, for example, regional prices for Asia were 40% greater on average than European prices and 150% higher than average prices in North and South America (FGE, 2012).

Hawaii's geographical location puts it in a position to take part in both Asian and North American markets. The dynamics and drivers of these markets are markedly different. In North America, gas markets are characterized as being more liquid and transparent (Galway, 2013). A majority of North American-produced gas is distributed via pipeline, and prices are based off of the Henry Hub (HH) price index. The main suppliers in North America include Western Canada, the U.S. East Coast, and the U.S. Gulf of Mexico. The majority of proposed liquefaction projects are concentrated on the U.S. Gulf Coast, two of which have received FERC approval. Despite ongoing environmental opposition, the U.S. West Coast may soon become a player in the North American market if LNG export terminals are approved. The growth of shale gas in the U.S. continues to be one of the main drivers of prospective LNG supplies. The continental U.S. is perceived as an attractive potential supplier for Hawaii's potential buyers because natural gas tends to have its own market, rather than be tied to the price of oil (ICF, 2013; FGE, 2012).

Unlike the gas-indexed prices of the Americas, prices in Asian markets are oil-indexed and are largely determined by the Japan Customs-Cleared Crude (JCC), also known as the Japanese Crude Cocktail. Oil-indexed natural gas prices tend to be higher than Henry Hub gas-indexed prices. Major suppliers for Asian markets include Eastern Australia, Qatar, and Malaysia. Major buyers such as Japan, Korea, and Taiwan have historically purchased LNG at higher oil-indexed prices for the purposes of securing long-term supply (Galway, 2013).

Therefore, where Hawaii could source its gas has a significant impact on the price Hawaii would pay for LNG. In addition the price index of the supply contract, delivered gas prices also reflect transportation costs, the cost of the receiving terminal, and the buyer's margin (FGE, 2007).

2.2 *LNG Procurement Options*

There are three basic LNG procurement options available to Hawaii if it chooses to invest in LNG. These options include buying: 1) based on long-term, oil-price linked contracts, 2) short-term/spot with tendering, and 3) buying U.S. liquefaction capacity and sourcing U.S. gas. Different combinations of these procurement options are also possible. A standard goal of energy pricing systems is to protect buyers and sellers from volatility and reduce the risk of default for both parties (FGE, 2007). The following provides a summary of the main characteristics of each procurement option in the context of a Hawaii-based market.

Long-Term Contract

Hawaii could establish a long-term contractual agreement for a period of 15 to 30 years. This long-term commitment would provide stability in pricing and sourcing, though allow for little volume flexibility. The terms of this contract would entirely determine whether bringing LNG to Hawaii could reduce its' high electricity rates. For example, because Canada and East-Australia gas prices are oil-indexed, it would provide little to no cost benefit for Hawaii (Galway, 2013). Galway (2013) has estimated that the Freight on Board (FOB) price for Hawaiian Electric Company (HECO) would be 13.8-15.0% of JCC (i.e. if JCC, the average price of crude oil imported to Japan, is \$120/bbl, then the FOB price of natural gas would be nearly \$18/mmbtu) depending on market conditions at the time of securing such a contract. Due to Canada's shorter shipping distance, it would be more attractive than Australia since delivered gas prices also reflect transportation costs (Galway, 2013). But this route is contingent on British Columbia and Canada approving exports from the West Coast of Canada.

Spot/Short Term Trade

LNG spot trading usually takes place when there is additional capacity in supply and receiving infrastructure (liquefaction, LNG tankers, and regasification facilities) and a larger number of players in the market. Spot markets include short-term trade as well as single- or few- cargo purchases (FGE, 2012). Spot markets are small, relatively unpredictable, and have hardly any impact on the LNG contract market (FGE, 2012). There has been recent growth of the short-term LNG market, however, prompted by the diversion of cargoes to higher value markets, expiration of long term SPAs, and equity lifts sold into the market (Galway, 2013). For Hawaii, procuring LNG on a spot/short term basis could be promising due to its relatively small demand (as well as a declining one) and its ability to act as a "wedge" customer once the majority of liquefaction capacity is committed (Galway, 2013).

Investment in the Emerging US Gas Market

Alternatively, Hawaii could look at investing early in liquefaction capacity from one of the proposed liquefaction plants on the U.S. West Coast. Since all of the proposed U.S. liquefaction projects include a sizeable amount of greenfield activity, Hawaii would take on a great deal of project development risk in addition to regulatory risk as projects cannot proceed until they are granted export permits (ICF, 2012). In other words, to secure a sound contract, Hawaii as the buyer must enter the U.S. market before sales are even made. This would require early investment in liquefaction capacity by becoming part of the project development process, perhaps before liquefaction projects are even approved (FGE, 2012). Hawaii's relatively small demand means that Hawaii will likely act as a "wedge-customer" to fill out sales of prospective U.S. projects (Galway, 2013).

With the recent boom in U.S. shale gas development, there have been 43 applications to export domestically produced LNG from the Lower-48 states since July 2014 (DOE, 2014). To build a liquefaction plant and export LNG, companies must obtain approval from Federal Energy Regulatory Commission (FERC), which evaluates the plants' environmental impact, and the U.S. Department of Energy (DOE), which has the authority to grant free trade agreement (FTA) and non-FTA export licenses. To date, only two companies, both of which are based in Louisiana, have received FERC approval—Cheniere (Sabine Pass) in April 2012 and Sempra Energy (Cameron LNG), in June 2014 (Snow, 2014; FERC, 2014). The two major export projects proposed on the West Coast are in Oregon—Jordan Cove and Oregon LNG—but continue to face strong environmental opposition (Ratner et al., 2013). For further discussion of environmental impacts, see Section 4.

2.3 Shipping Considerations

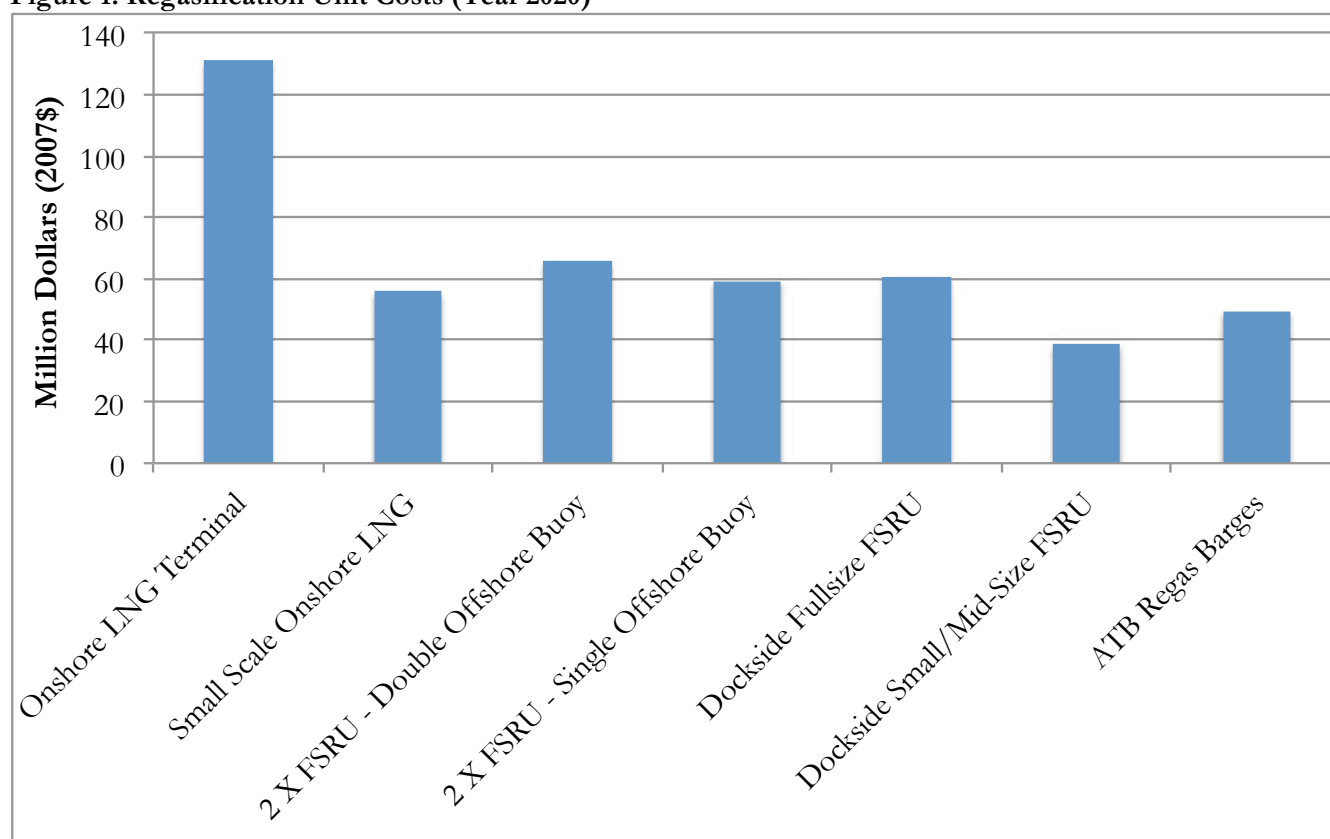
If Hawaii sources LNG from the United States, it would have to operate all shipments on vessels that are in compliance with the Merchant Marine Act of 1920, otherwise known as the Jones Act. The Jones Act is a federal statute that requires all goods shipped between U.S. ports be carried on U.S.-Flagged ships constructed in the United States that are owned and crewed by U.S. citizens. Jones Act vessels are more expensive to operate than foreign vessels (MARAD, 2011). While Jones Act exemptions have been granted during catastrophic events like Hurricane Sandy, rarely is it waived (ICF, 2012). As such, Hawaii would have to compete with larger markets for limited shipping options that are compliant to the Jones Act. However, as FGE (2012) points out, the Jones Act is not problematic if LNG is sourced from the USWC. Articulated tug barges (ATBs) do not require a Jones Act Waiver (the U.S. Coast Guard ruled that LNG barges comply with the Jones Act) and can cover the distance from the USWC to Hawaii.

In the United States, some liquefaction contracts run on a “tolling” basis where the buyer is responsible to procure gas feedstock and the liquefaction plant charges a flat fee for every tonne of the LNG produced (FGE, 2012). Hawaii would be responsible for shipping if it chooses to procure tolling capacities in the US or decides to use small and mid-scale infrastructure (Galway, 2013). Participation in DES versus FOB sales will also impact the choice of shipping infrastructure. Most importantly, shipping methods must be compatible with the configuration of the receiving terminal.

2.4 Destination Terminal Investment Options

The development of an LNG receiving terminal and other necessary infrastructure in Hawaii would be a large undertaking that would demand considerable capital and support from various stakeholders. Galway (2013) and FGE (2012) discuss in detail the different types of terminals to receive LNG—from an onshore receiving terminal to an offshore buoy-based floating system and near-shore (shore side) floating storage regasification unit (FSRU), as well as standard scale terminals versus mid-to-small scale options. An estimated range in regasification costs in year one is illustrated in Figure 1.

Figure 1. Regasification Unit Costs (Year 2020)



Source: Galway, 2013.

Due to both siting considerations and economics, Hawaii has limited choices for the type of regasification infrastructure. While onshore receiving terminals are the most common option throughout the U.S, it would be the most capital-intensive option for Hawaii. Galway (2013) estimated that an onshore terminal would cost \$0.5-1.5 billion (depending on size and siting of the terminal) and would take 3-5 years to construct. For Hawaii, this type of facility would require approximately 100 acres of land and a dock in calm waters (ICF, 2012). Given the relatively small volumes of LNG that Hawaii anticipates to import, it would be difficult to achieve economies of scales needed to site a standard size regasification terminal onshore.

An offshore floating system, on the other hand, can generally be implemented faster than onshore facilities and are less costly. FGE (2012) estimated that offshore systems would take about a year to construct. The volume of LNG delivered is a primary determinant of the unit/throughput cost; with lower capital expenditure costs of

offshore systems, economies of scale can often be realized at smaller volumes in comparison to onshore systems. Even though there are lower unit costs realized by small and mid-scale regasification options, significantly lower shipping efficiencies with small or mid-scale shipments may offset the regasification cost advantages (Galway, 2013).

Nonetheless, the underlying hurdle with a floating offshore terminal for Hawaii is that once LNG reassumes its gaseous form, it removes the possibility for other uses of LNG such as ground and marine transportation and delivering LNG to neighboring islands unless the regasified LNG is then reliquefied onshore. FGE (2012) concluded that this did not make economic or strategic sense (FGE, 2012).

As such, the type of LNG terminal infrastructure is most logically limited to a near-shore berth-based FSRU—either a single-berth or double-berth configuration. In a single berth arrangement, the FSRU is moored and the LNG carrier pulls up alongside of the FSRU; the LNG is then transferred via ship-to-ship (STS). In the case of a double-berth FSRU, the delivery vessel has a dedicated berth at the dock. The delivery vessel and the FSRU are located on opposite sides of a jetty and the LNG is transferred from the LNG carrier over the jetty to the FSRU (i.e. across the berth transfer) (Galway, 2013). As indicated by Galway (2013), the preferred location for a bulk LNG terminal is an FSRU in Pearl Harbor. Functionally, Pearl Harbor is an ideal site for an FSRU due to its location in calm waters and near the major load centers as well as meeting other key project aspects and potentially providing ancillary benefits to the U.S. Navy (Galway, 2013). Kalaheo Barber's Point Harbor (KBPH), is also a well-protected harbor, but berthing requirements, harbor dredging, and the high utilization of the harbor poses challenges (Galway, 2013).

3. LNG Price Projections and Electric Sector Costs

3.1 LNG Price Projections

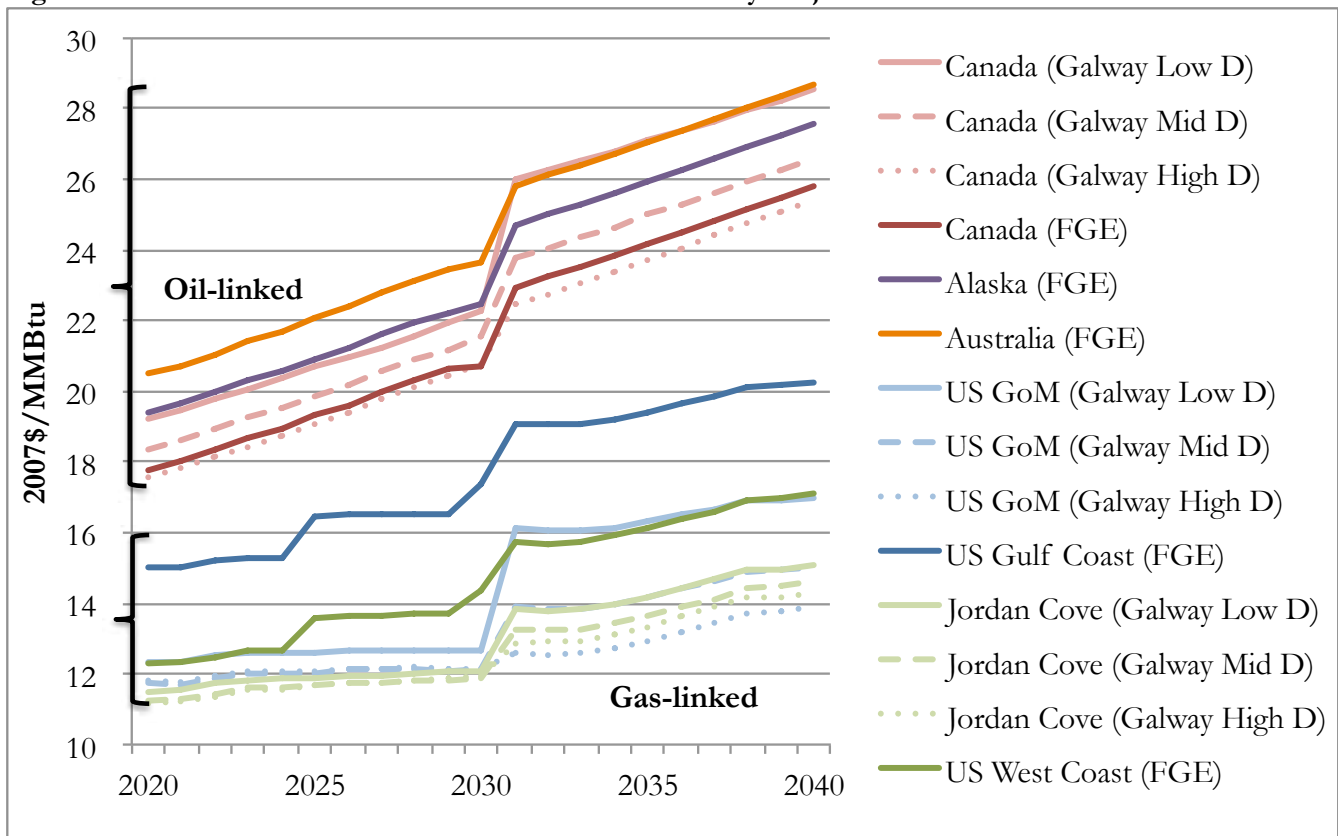
The options and considerations outlined above in Section 2 are factors affecting the price of importing LNG to Hawaii for use in the electric sector. Using the two most recent (and detailed) studies of potential LNG markets, Galway (2013) and FGE (2012), we aggregate their delivered cost price projections and normalize them to \$2007/mmbtu in Figure 2 below. The major components of delivered cost¹ include the FOB price (fuel plus liquefaction), transportation/shipping costs², and regasification costs.³ Fuel, is by far the largest determinant. Oil-linked prices from Canada, Australia, and Alaska are distinguished from gas-linked prices in the U.S. West Coast and Gulf Coast.

¹ To a lesser extent, boil off and regasification loss are factored into the delivered cost.

² FGE uses estimates from their Shipping Rate Calculation Model for a 25,000 cbm tanker under the assumption of a Jones Act waiver for gas sourced from the USWC, USGC, and Alaska. For the USWC, the cost of transporting LNG via ATBs is equivalent to non-U.S. tanker rates, implying that the Jones Act does not impact costs. Shipping USGC-sourced gas costs two-and-half-times as much as from the USWC since twice the distance is covered and Panama tolls are incurred enroute. Galway on the other hand, assumes Jones Act compliant FSRUs for shipping gas from the USWC and USGC (i.e. cost of complying with Jones Act is accounted for in shipping costs). Transportation costs vary by supply source, vessel type, and LNG volume.

³ Regasification costs are illustrative of both an onshore terminal and various FSRU configurations. On an energy content basis (\$/mmbtu), the range between the two alternatives is relatively small. FGE models an onshore terminal while Galway assumes regasification costs for FSRUs (U.S. GoM: 2xFSRU double buoy, Jordan Cove-Dockside FSRU, Canada- 2xFSRU double buoy).

Figure 2. Normalized Delivered Cost to Hawaii – Prior Study Projections



Source: FGE, 2012; Galway, 2013.

Figure 2 illustrates the range in projected LNG prices—from Galway’s high demand scenario (assumes 0.85 mtpa from 2015-2029, and falls to 0.55 mtpa in 2030) to its low demand scenario (.525 mtpa in the early years, and tapers off to .275 mtpa in 2030), and FGE’s forecasts. The source of LNG clearly dictates the price, with the highest prices corresponding to countries where the price of LNG is tied to that of oil, and lower LNG prices originating from the U.S. where LNG prices are linked to Henry Hub. Sourcing from Canada is an example of procuring LNG on a traditional price and terms as well as purchasing short term or spot through tendering, while the U.S. West Coast/Jordan Cove and the U.S. Gulf Coast is clearly the procurement option where U.S. liquefaction capacity is bought or U.S. gas is sourced.

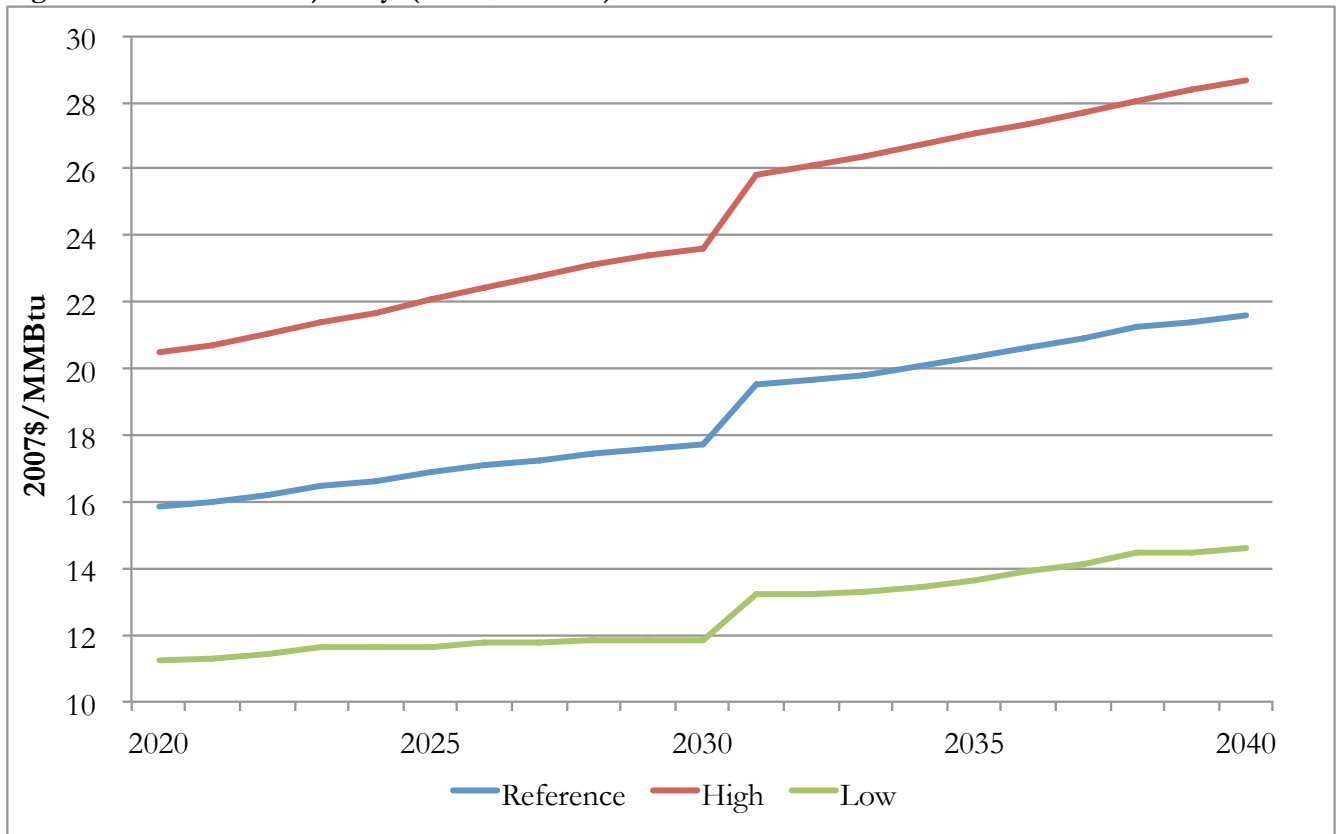
Our models employ EIA’s Annual Energy Outlook (AEO)’s 2013 reference forecast for oil prices (Brent). Since FGE’s LNG price projections are based on the imported crude oil price in *AEO 2012*, we adjust their forecast to *AEO 2013* by applying the percent change between the *AEO 2012* and *AEO 2013*. We convert FGE’s forecast from \$2012/MMBtu to \$2007/MMBtu using the U.S. Consumer Price Index (CPI), and since their price projections end at 2030, we extend their forecast through 2040 using the difference between years in Galway’s Demand 2 (middle demand) scenario.⁴ For Galway, since their forecast is derived from *AEO 2013* which is in nominal dollars, we convert their forecast to real dollars using the *AEO* GDP deflator and normalizing to \$2007 using U.S. CPI.

In our model, we adopt FGE’s Australia price (the highest price path overall) as the “high” gas price; Galway’s middle demand scenario for Jordan Cove (the lowest price path among the three in Galway’s middle

⁴ Specifically, we apply the difference between years in Galway’s (2013) “Jordan Cove” to FGE’s (2012) “USWC”; Galway’s (2013) “Gulf of Mexico” to FGE’s (2012) “USGC”; and Galway’s (2013) “Canada” for FGE’s oil-linked sources—Alaska, Australia, and Canada.

demand) as the “low” gas price, and our reference price averages the two.⁵ Figure 3 represents the primary natural gas price data we use within our study.

Figure 3. LNG Price Trajectory (2007\$/MMBtu)



3.2 Investing in New Power Plants

Another important factor in determining the cost of using natural gas for electricity in Hawaii is the means by which it is burned. If natural gas becomes a part of Hawaii’s energy mix, electric utilities could either burn it in existing generators or build new combined cycle gas turbines (CCGT) or simple cycle gas turbines (SCGT). In addition to higher efficiency, newer gas turbines can act as a strong complement to intermittent renewable resources because gas turbines can provide better load-following capacity (IEA, 2010; MIT, 2013).

Within this study, we assume cost and efficiency parameters for existing and new power plants as outlined in Table 3 (see Section 5). The cost of a new conventional CCGT, adopted from Hawaiian Electric Companies 2013 Integrated Resource Plan (IRP), \$3,110/kW (\$2007). This drastically differs from EIA’s 2013 overnight capital cost estimate of \$1,202/kW (\$2007) for a new conventional CCGT in Hawaii. The large cost disparity stems from varying systems designs in terms of capacity and configuration of gas and steam turbines. EIA’s estimate is based on a reference capacity of 620 MW (EIA, 2013c), which is considerably large given Hawaii’s electricity demand profile while the IRP’s estimate is for a 59 MW plant in a 1x1 configuration (Hawaiian Electric Companies, 2013a). FGE (2012) suggests a more appropriate estimate generated by General Electric’s engineering software package, GT-pro, of \$1,331/kW for a 113 MW plant, with 2 gas turbines and 1 steam turbine (2x1 configuration). For model consistency however, we adhere to the IRP’s estimate. This makes our findings somewhat conservative when estimating the optimal amount of new CCGT capacity.

⁵ Note the kink in price in year 2030 is because of Galway’s adoption of decreasing demand over time—meaning that LNG serves as a bridge fuel (by assumption). Though Galway’s assumption is counter to our finding that gas use persists once adopted, the selection of price scenarios is simply representative of a range of possible pathways.

To account for the cost of retrofitting existing gas units and constructing pipelines, we adopt FGE’s cost of retrofitting an Oahu peaker plant. These costs amount to a total of \$15/MWh (\$3/MWh for retrofitting and \$12/MWh for pipeline construction), which is added to the VOM.

4. LNG Environmental Considerations

The development, transport, and use of natural gas have a variety of environmental impacts ranging from GHG emissions to water resources.

Natural gas is sourced either conventionally or unconventionally. Conventional natural gas extraction typically occurs closer to the earth’s surface, beneath rock layers with high permeability and flows freely to the surface with simple drilling methods. In contrast, unconventional natural gas extraction occurs much further beneath the surface of the earth within rock with extremely low permeability. Unconventional resources are less concentrated than conventional resources and do not flow freely to the earth’s surface. Unconventional natural gas extraction requires the use of technologies such as hydraulic fracturing. The most common types of unconventional natural gas include coalbed methane, tight natural gas, and shale gas. In general, unconventional gas production has a significantly greater environmental footprint than conventional gas development (IEA, 2012).

4.1 Greenhouse Gas Emissions

4.1.1 Greenhouse Gas Emissions Factors

Natural gas is often touted as a “clean” energy source because it produces fewer GHG and particulate emissions than coal and oil in combustion. The burning of natural gas produces primarily carbon dioxide and, to a lesser extent, nitrogen oxide. Natural gas is essentially methane (CH₄), constituting about 90 to 95 percent of natural gas by volume. Methane’s global warming potential is 72 times more than carbon dioxide over a 20-year time frame (IPCC, 2007). As such, methane is emitted if natural gas is not burned completely, or during extraction and transportation (EPA, 2014a). Emissions of sulfur dioxide and mercury compounds are small (EPA, 2014a). For illustrative purposes, the out-of-stack emissions coefficients for carbon dioxide, methane, and nitrogen oxide are shown below in Table 1.⁶

Table 1. Natural Gas, Oil, and Coal Stationary Combustion Emissions Factors (g CO₂e/MMBtu)

	CO ₂ Factor	CH ₄ Factor	N ₂ O Factor
	<i>g CO₂e/MMBtu</i>		
Natural gas	53,060	25	30
Residual Fuel Oil No. 6	75,100	75	179
Bituminous Coal	93,280	275	477

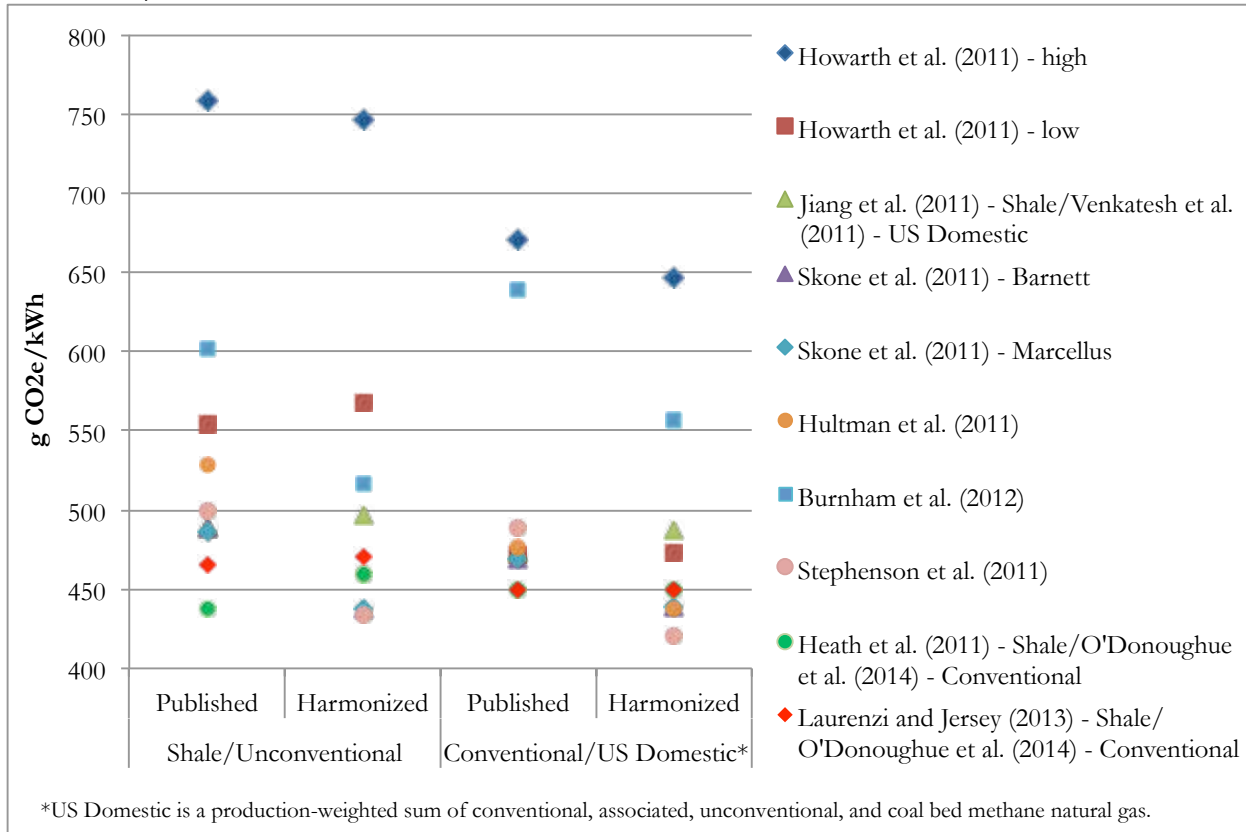
⁶To obtain emissions factor in carbon dioxide equivalent, emissions factors for CH₄ and N₂O are adjusted using 100-year GWP values from the IPCC’s Fourth Assessment Report (2007).

Source: EPA, 2014b.

The production of natural gas additionally produces GHG emissions, for example from the use of diesel motors during extraction. The impact is generally higher for unconventional sources (Howarth et al., 2011; Stephenson et al., 2012). However, there is a high degree of uncertainty in understanding the emissions profiles of the various methods of natural gas production due to discrepancies in field measurements along with methods of modeling the different input variables essential for a complete lifecycle analysis (Howarth et al., 2011; Hultman et al., 2011; Shindell et al., 2009; Wigley, 2011). Heath et al. (2014) try to overcome this limitation in a meta-analysis of lifecycle natural gas GHG emissions studies, using a harmonizing technique between methodologies. The lifecycle GHG emissions, taking into account production, transportation and combustion, of a variety of sources of natural gas is shown in Figure 4 below, adopted from Heath et al. (2014). “Published” refers to the original studies published results and “harmonized” refers to the authors’ new estimate based on harmonizing methodologies.

⁶ All fuels/technologies emissions coefficients are accounted for within HELM.

Figure 4. Lifecycle GHG emissions from power generation using different types/mixes of natural gas (g CO_{2e}/kWh)



Source: Heath et al. (2014)

As shown above, unconventional sources of natural gas generally tend to have higher lifecycle GHG emissions, but also greater variation depending on the source. Within the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model, for example, shale gas is estimated to have a well equipment emissions factor of 43.8 g CO_{2e}/kWh and conventional sources 39.4 g CO_{2e}/kWh. This is from production, processing, transmission and distribution (i.e. without combustion). The reasons are that unconventional sources of natural gas tend to require additional production steps, such as hydraulic fracturing, as well as flaring and venting. With flaring, well-to-burner emissions are estimated to be 3.5% greater than conventional gas related emissions and 12% greater when gas is vented (IEA, 2012). Eliminating venting and flaring by developing techniques to capture gas during flow-back and well completion would reduce these emissions. It is still not, however, currently economical for companies to eliminate venting from production processes. Also, venting is often necessary for equipment maintenance and safety operations (EPA, 2010). The lifecycle emissions factors for natural gas from the GREET Model (2013) are shown in Table 2 below.

Table 2. GREET Model Estimates for Natural Gas GHG Emissions (g CO_{2e}/MMBtu)

Sector	Process	Conventional	Shale
Production	Completion	13	1,070
	Workover	0	215
	Liquid Unloadings (Venting)	255	255
	Well Equipment (Leakage and Venting)	3,175	3,175
	Well Equipment (CO ₂ from Venting)	21	21
Processing	Processing (Leakage and Venting)	925	925
	Processing (CO ₂ from Venting)	849	849
Transmission	Transmission and Storage (Leakage and Venting)	2,185	2,185
Distribution	Distribution (Leakage and Venting)	2,355	2,355
	Distribution – Station (Leakage and Venting)	1,775	1,775
Liquefaction^b		18,757	
Regasification^b		5,861	
Total Mine to Plant		36,170	37,443

^aUnless otherwise noted, emissions released in the production, processing, transmission, and distribution phases are from methane. Methane emissions are converted to carbon dioxide equivalent using 100-year GWP values from the IPCC's Fourth Assessment Report (2007).

^bLiquefaction and regasification emissions are taken from a 2014 study by NETL. These estimates are presented in kg CO_{2e}/MWh. To convert to an energy content basis (MMBtu), we use 1 kWh = 0.003412 MMBtu.

Source: Argonne National Laboratory, 2013; EPA, 2013; NETL, 2014.

Liquefied natural gas also involves liquefaction and regasification activities, both of which contribute to the full lifecycle emissions profile of generating power from natural gas. A 2014 study by the National Energy Technology Laboratory (NETL)—a research arm of the U.S. DOE—estimates the emissions factor for liquefaction to be 18,757 g CO_{2e}/MMBtu, and regasification, 5,861 g CO_{2e}/MMBtu.

4.1.2 Greenhouse Gas Emissions Reduction Policies

The State of Hawaii adopted binding GHG emissions targets in 2007. Act 234 requires Hawaii to reduce its statewide GHG emissions to 1990 levels (excluding aviation) by January 1, 2020. It also urges the minimization of “leakage,” or the export of Hawaii’s emissions elsewhere. The Department of Health (DOH) developed rules for compliance within the electric sector, which were signed by the Governor in July 2014. Existing stationary sources that emit over 100,000 short tons of carbon dioxide equivalent annually, with the exception of municipal waste combustion and municipal waste landfills, are mandated to reduce their GHG emissions by 16% from 2010 levels by January 1, 2020. The rules allow for flexibility in that affected facilities may partner among each other to be in compliance, and biogenic emissions are currently excluded (HAR, Chapter 11-60.1). Because out-of-stack emissions are solely considered within the rules, using natural gas in Hawaii’s electric sector could help identified facilities (and companies) to meet their regulatory requirements (if not necessarily the spirit of the Act). If these rules are expanded to include upstream production emissions, this perceived reduction in GHG emissions would decrease – though the magnitude depends on sourcing and production practices.

The Federal government, through the Environmental Protection Agency (EPA), is also regulating GHG emissions through provisions within the Clean Air Act (CAA). Under Section 111(b) of the CAA, new fossil fuel-fired electric generating units (EGUs) will be subject to new source performance standards. The proposed standards limit new large natural gas-fired power plants CO₂ emissions to 1,000 pounds per MWh (smaller plants are limited to 1,100) and new coal-fired plants will either have to emit only 1,100 pounds per MWh over one year, or the plant can take 7 years to get average emissions down to 1,050 pounds per MWh (which is more flexible than the initial proposed rule) (Office of the Federal Register, 2014a). It is still uncertain whether these standards would be enforced on a facility-level, between like-technologies, or system-wide.

In addition, the Clean Power Plan that was proposed in June 2014 lays out carbon pollution standards for existing power plants under Section 111(d) of the CAA. To cut power generation emissions by 30% by 2030 relative to 2005 levels, the Clean Power Plan sets emissions rates (lbs of CO₂ per MWh) for each state, using 2012 as the baseline (Office of the Federal Register, 2014b). Most notably, the plan provides flexibility, allowing implementation of a variety of measures from energy efficiency to renewable energy, for States to achieve the emissions targets. Hawaii has made strides in this regard. Hawaiian Electric Companies have reduced their greenhouse emissions by over 22% between 2005 and 2013 (Shimogawa, 2014b).

4.2 Air Quality Regulations

The EPA is in the process of introducing Mercury and Air Toxics Standards (MATS) and National Ambient Air Quality Standards (NAAQS), also under the CAA. This is another motivating factor to introduce natural gas to Hawaii's electricity mix.

The rules under MATS finalize the standards set by the 1990 Clean Air Act amendments to limit mercury and other toxic pollutants such as arsenic, nickel, nitrous oxides, chromium, sulfur dioxides, and acid gases emitted from existing coal- and oil-fired electric generating units (EGUs) with a capacity of 25 megawatts or greater. The requirement therefore applies only to HECO's steam units (Hawaiian Electric Companies, 2013b). When comparing MATS to HECO's current filterable particulate matter emission rates, it is clear that all of the HECO's units as currently operated exceed the MATS and are therefore not in compliance (ICF, 2012). MATS are to be implemented by 2015, although states are allowed an additional year through the Department of Health, and under more stringent conditions, a one year extension from the EPA.

NAAQS regulates six principal air pollutants—carbon monoxide, lead, nitrogen dioxide, ozone, particle pollution, and sulfur dioxide. The compliance deadline for NAAQS is in 2022 and applies to all generation units. Sulfur dioxide concentration standards are much lower than the sulfur content of the LSFO currently consumed in HECO's units as well as the intermediate fuel oil (IFO) used in MECO's and HELCO's units (Hawaiian Electric Companies, 2013b).

The options to comply with these stricter environmental regulations are limited, both in terms of its cost effectiveness and time frame. For example, HECO will not be able to continue burning LSFO as usual. It would have to switch to an LSFO-blend or diesel fuel and/or modify operating and maintenance practices (Hawaiian Electric Companies, 2013b). LNG could provide a long-term solution, but the timeframe for the legislative, contractual, and permitting processes required to construct an LNG regasification and storage terminal would far exceed the 2016/2017 deadline for MATS compliance. Nonetheless, to expedite LNG into their power generation mix, Hawaiian Electric Companies issued an RFP in March 2014 for 800,000 tons of containerized LNG per year, for a period of 15 years, beginning in 2016 or 2017 (Hawaiian Electric Companies, 2014b). Hawaiian Electric Companies is likewise pursuing LNG to be in compliance with NAAQS since it is estimated to be more cost-effective over installing expensive back-end controls—estimated to be in the range of \$1 billion (Hawaiian Electric Companies, 2013a; FGE, 2012)—or switching to a lower sulfur fuel (Hawaiian Electric Companies, 2013b).

4.3 Impacts to Water Resources and the Local Environment

The controversy surrounding unconventional gas development through hydraulic fracturing largely stems from the environmental impact to water resources. Hydraulic fracturing is a water-intensive process where 1000 to 4000 tonnes of water, sand, and chemicals are injected underground at high pressure to fracture the rock surrounding an oil or gas well (IEA, 2012). The quantity of water used, water contamination from fracking fluids, chemical spills, migration of stray gas, and waste disposal are among the major issues (USGS, 2013; Rahm and Rita, 2012; Nicot and Scanlon, 2012; Rahm, 2011; Kargbo et al., 2010). Other concerns include air quality and land use disruptions for well pad construction, service roads, and pipeline networks (Rahm and Rita, 2012; Rahm, 2011; GPO, 2011).

Groundwater and Surface Water Contamination

There are several ways during the fracking process that groundwater and surface waters can become contaminated with fracking chemicals and naturally occurring earth elements including heavy metals and radioactive materials. The first major cause of water contamination is through leaking surface holding ponds, also referred to as pits, where drilling fluids and wastes are temporarily stored before they are injected into the well boreholes (NETL,

2009). Containing these fluids are the most important in preventing surface water contamination (NETL, 2009). The second threat to both ground and surface water can be attributed to the millions of gallons of flowback of produced waters or wastewater after a frack takes place. Fracking flowbacks are the fluids pumped out of the well and separated from the oil and natural gas. For shale formations, about 20% to 50% of the fracking fluid inputs return back to the surface during the several weeks of flowback while the rest stay bound to the clays in the shale rock (IEA, 2012).

Spills and Leaks

Like all other forms of fossil fuel extraction, hydraulic fracturing comes with risks involving accidental spills and leaks of fracking fluids, chemical additives, flowback, and produced water. There is also risk associated with vandalism or intentional dumping of wastewater from flowback slurry and produced waters. Chemicals discharged onto the ground from spills, leaks, and illegal dumping can run off into surface water ways or percolate into the groundwater (Cooley et al., 2012). In addition to potential leakage at the ground surface, it is possible for leakage of fracturing fluids into shallow aquifers. This may occur if there is imperfect sealing of the cement column around the casing and if insufficiently treated wastewater is discharged into the water table (IEA, 2012). Likewise faulty seals to prevent gas leakage into aquifers are the most common problem with well construction (Vidic et al., 2013).

Abandoned Wells

In addition to groundwater contamination from active well sites, abandoned well sites function as major migration pathways for fracking contaminants to enter the groundwater and methane to continue vent into the atmosphere. Unlike conventional wells, which last 30 years or more, recoverable gas in unconventional wells is usually extracted for one to three years since output typically declines by 50% to 75% within the first year of production (IEA, 2012). With the recent growth in unconventional gas development, hundreds of thousands of wells will be removed from service each year. In 2008, the Interstate Oil and Gas Compact Commission estimated that there were approximately 150,000 undocumented and abandoned natural gas wells throughout the United States (IOGCC, 2008).

Wastewater Management

After fracking, wastewater sits in evaporations ponds and gas companies must dispose of the remaining wastewater. Due to the U.S. EPA's 1988 determination to exempt oil and gas companies from hazardous waste regulations under the RCRA, natural gas companies are not federally required to dispose of the remaining wastewater in the Class I hazardous waste wells. Because of this, the primary method of disposal is by injection into Class II wells where the waste is injected deep underground into porous rock formations, such as limestone or sandstone. Class II injections can occur under only a shallow soil layer. Since Class II wells are not held liable to the rigorous requirements of Class I wells, they present a substantially greater risk of causing earthquakes and contaminating groundwater than Class I wells (Cooley et al., 2012; Veil, 2010). States that do not have the capacity to accommodate additional wastes from fracking operations in their injection wells often haul the waste water to neighboring states for disposal in commercial Class II wells. The U.S. EPA has estimated that there are 28,800 Class II wells in the United States that are specifically used for the disposal of fracking wastes (Veil, 2010).

For coalbed methane production specifically, during the dewatering processes, produced water is commonly discharged into existing drainage systems, sent to shallow ponds for evaporation, re-injected into underground formations, or used for irrigation once it is properly treated. The U.S. EPA (2010) has estimated that 47 billion gallons of produced water were pumped out of coal seams in 2008. About 22 billion gallons of produced water, or about 47% of the total, were discharged into surface waters in 2008 with little or no treatment (EPA, 2008). This is especially problematic since produced water is often very salty and sodic (having high concentrations of sodium, calcium, and magnesium).

Storm Water Management

Expansive disturbances to the land surface caused by fracking operation activities have had notable impacts on the timing, volume, and composition of storm water runoff. These land disturbances primarily are associated with vegetative clear-cutting for well pads, access roads, waste pits, truck parking, and equipment storage. An average well pad covers 7 to 8 acres in land area. The U.S. EPA (2004) has estimated that a one-acre site without runoff controls can contribute 35 to 45 tons of sediment runoff each year. Not only does this runoff carry sediment, it also carries

fracking chemicals and other hazardous substances from storage pits, slurry evaporation ponds, and equipment into local waterways.

Water Withdrawals

The amount of water required for the hydraulic fracturing process varies greatly throughout different regions of the United States. Water consumption per well largely depends on the depth of the shale bed, the geology of the shale's age and formation thickness, technological factors such as whether horizontal or vertical drilling is necessary or if recycled water can be used, the proximity of freshwater sources, and regulatory factors (Cooley et. al., 2012; Mielke et. al., 2010). The U.S. EPA (EPA, 2011a) estimates that between 2.3 and 3.8 million gallons of water are required to conduct one frack per well over a 2- to 5-day period. The Texas Water Development Board (2011) reports that water requirements to frack in Texas's Eagle Ford Shale average 13 million gallons of water per well. These figures do not include the 40,000 to 1,000,000 gallons of water required to drill an individual unconventional gas well (Arthur et al., 2009).

Environmental Policy Exemption

Much of the uncertainty in regards to the impact of hydraulic fracturing on water resources stems from policy initiatives set forth by the 2005 Energy Policy Act (EPA), which has played a role in stimulating domestic production of unconventional gas (Cooley, 2012; Sherlock, 2011; American Gas Foundation, 2007). The Act grants various domestic gas production incentives—from spending, tax, and deregulatory provisions—as well as terms supporting new supply sources and LNG development (including terminals and other infrastructure such as natural gas pipelines) (Sherlock, 2011; Toder, 2007). A prime example of deregulatory clauses in the EPA is the exclusion of “underground injection of fluids or propping agents (other than diesel fuel) pursuant to hydraulic fracturing operations related to oil, gas, and geothermal production activities” in the definition of “underwater injection,” which is regulated by the EPA under the Safe Drinking Water Act (US EPA, 2002). This exclusionary language is also known as the Halliburton loophole (Sakmar, 2010). The Fracturing Responsibility and Awareness of Chemicals (FRAC) Act, proposed in 2009 though unsuccessful, attempted to amend the EPA by subjecting oil and gas hydraulic fracturing activities to the SDWA as well as require chemical disclosure⁷ (Sakmar, 2010). The precise mixtures remain “proprietary,” though since 2010, voluntary disclosure of the chemical composition of fracking fluids has become more prevalent throughout the U.S. There is uncertainty however as to whether companies fully reveal all chemicals (IEA, 2012).

In addition to the SDWA, the gas industry is also exempt or excluded from select parts—many of which are a consequence of the EPA—of the following pieces of federal environmental legislation.

National Environmental Policy Act (NEPA)

The NEPA of 1969 requires federal agencies to assess environmental impacts of proposed projects as well as consider alternatives. This is carried out through first conducting an Environmental Assessment to determine if such action would cause significant environmental impact; if deemed the case, an Environmental Impact Statement is required and shared with the public for comments (42 U.S.C. §4321 et seq.). The language of the EPA, however, created a “rebuttable presumption” for oil and gas activities to fall under the less stringent “categorical exclusion” meaning that unless the public proved otherwise, the development of natural gas is presumed to not impose harm on the environment (Brady, 2012). In short, the EPA no longer triggered a comprehensive environmental review under NEPA.

Clean Water Act (CWA)

The CWA (1972) regulates surface water quality and discharge of pollutants into U.S. waters. Stormwater runoff from “oil and gas exploration, production, process, or treatment operations or transmission facilities” are exempt from acquiring permits for discharging pollutants as long as the system of conveyances do not come into contact with waste and materials and products from the operations site (33 U.S.C. §1251 et seq.); the EPA expanded the exemption to include oil and gas construction facilities (Brady, 2012).

⁷ It was later reintroduced in the following congressional session which commenced in 2011, but again the bill died; the latest attempt was in 2013.

Clean Air Act (CAA)

The CAA, passed in 1970, is aimed at protecting air quality for the health and welfare of the public. Although small sources located in proximity and under common control are treated as a “major source”—and therefore subject to emissions standards—oil and gas wells (as well as associated facilities) are exempt from aggregation (42 U.S.C. §7401 et seq.). Therefore, they do not have to comply with the National Emissions Standards for Hazardous Air Pollutants (NEHAPS) by installing the Maximum Achievable Control Technology (MACT).

Resource Conservation and Recovery Act (RCRA)

Enacted in 1976, the RCRA creates a cradle-to-grave regulatory program for managing hazardous waste. Initially, oil and gas waste was temporarily excluded from the list of hazardous wastes pending a study and Regulatory Determination by the EPA (NETL, 2009; 42 U.S.C. §6901 et seq.). In 1988, the EPA ruled regulation of hazardous oil and gas waste under Subtitle C of RCRA unnecessary in light of existing Federal and State regulatory programs (GWPC and ALL Consulting, 2009; 42 U.S.C. §6901 et seq.). As a result, oil and gas waste is bounded by less stringent regulation under Subtitle D—non-hazardous solid waste (EPA, 2012a; 42 U.S.C. §6901 et seq.).

Comprehensive Environmental Response, Compensation, and Liability Act (Superfund Act or CERCLA)

CERCLA, is related to RCRA, but instead of handling materials to be disposed of or recycled from active and future facilities, CERCLA manages the clean up of hazardous waste sites that are either inactive or abandoned. CERCLA (1980) creates a fund, known as the Superfund, for cleaning up toxic materials. The Superfund is financed by taxes on chemical and petroleum industries (EPA, 2011b; 42 U.S.C. §9601 et seq.) Under CERCLA, the EPA has the authority to hold responsible parties accountable for the clean-up costs. However the term “hazardous substance” does not include oil and gas under CERCLA (42 U.S.C. §9601 et seq.)

Emergency Planning and Community Right-to-Know Act (EPCRA)

The EPCRA (1986) is designed to inform communities of toxic chemicals released into the air in order to protect public health, safety, and the environment from chemicals hazards (EPA, 2014c). Section 313 of the EPCRA requires manufacturing facilities to report their toxic chemical release annually if they have ten or more employees and if they are manufacturing, processing, or using levels beyond the toxic chemical threshold quantity (42 U.S.C. §11001 et seq.). Industries with a Standard Industrial Classification code (SIC code) of 20-39 must comply; the oil and gas industry (SIC code 13) is excluded (42 U.S.C. §11001 et seq.).

Policy Responses

In response to the lack of federal oversight, individual states have assumed the regulatory burden of shale gas development and its impact on water resources. All 27 states that produce oil and gas have permitting requirements for exploration and production (E&P) including locating, drilling, completion and operation of wells (NETL, 2009). As of May 2012, 19 states have introduced over 100 hydraulic fracturing-related bills, most of which are directed towards requiring chemical disclosure and monitoring fluids (Pless, 2012). Other proposed legislation covers water use and quality, well regulation and inspection, air quality, and banning hydraulic fracturing (Pless, 2012). Colorado for instance has been successful in implementing a range of measures governing oil and gas development—from applying for permits to drill, further authorization for performing enhanced recovery options (i.e. fracking), to maintaining Material Safety Data Sheets for hazardous chemicals as well as a chemical inventory (Brady, 2012). On the end of the spectrum, New York has had a moratorium on hydraulic fracturing of Marcellus Shale since 2008 and is still undergoing the environmental review process, prior to issuing any drilling permits (NYDEC, 2014). Pennsylvania, Texas, Louisiana, and Wyoming are also examples of states that have implemented their own set of regulations (Brady, 2012).

The Federal government is revisiting the issue of hydraulic fracturing through a national study to better understand its impact on water resources, specifically on drinking water (EPA, 2014d). In 2009, the U.S. Congress tasked the EPA to research this relationship due to increasing public concern and expected growth in natural gas E&P. A 2011 report by the U.S. House of Representatives Committee on Energy and Commerce found that between 2005 and 2009, hydraulic fracturing fluids used by fourteen hydraulic fracturing service companies consisted of 29 chemicals that were known or possible human carcinogens, regulated under the SDWA, and considered hazardous pollutants under the CAA (U.S. House of Representatives, 2011). To date, the EPA has completed a

progress report (2012) outlining their study objectives to examine the potential impacts of hydraulic fracturing at each of the five stages of the hydraulic fracturing water cycle—water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and waste disposal—in the (EPA, 2012b). The EPA will release the draft assessment report in late 2014 (EPA, 2014e). In addition, in 2012 the U.S. EPA, DOI, and DOE signed a MOA for a joint effort in unconventional oil and gas research (DOE, 2012). More recently, the EPA has issued a proposed rule to require chemical information disclosure under the Toxic Substances Control Act (TSCA). They are currently seeking comments on which substances and mixtures should be reported as well as the means of acquiring this information (EPA, 2014c; Office of Federal Register, 2014c).

5. Electric Sector and Economy-Wide Analysis

5.1 Model Description & Data

In this study we use two complementary models that are built and maintained by UHERO. The Hawaii Electric Sector Model (HELM) is a bottom-up model of the electric sector while the Hawaii Computable General Equilibrium Model (H-CGE) is a top-down model of Hawaii's overall economy and covers production from all other sectors.

5.1.1 HELM

HELM is a fully dynamic, partial equilibrium model of Hawaii's electric sector. It solves for the least-cost mix of generation subject to demand, regulatory requirements, and system constraints. It dispatches electricity against a load duration curve with 84 different load blocks that represent variation in load throughout the day and year. It is calibrated to existing electric generating units for Hawaii's four counties in 2013 (and scaled to \$2007). It solves in 5-year intervals from 2015 until 2040. Future energy price forecasts are based on the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2013 and, for this study, based on the reference forecast. Electricity demand is determined endogenously within H-CGE model (described below) and feeds into HELM as a data input.

Information on costs and physical characteristics of units (as shown in Table 3 below) is constructed from several publicly available sources – including the utilities' IRPs which are mandated by the Public Utilities Commission (PUC), submitted "rate case" approvals to the PUC, and the U.S EIA's state energy database. Several parameters are needed to fully define the existing and potential (new) units' costs and operating characteristics. Existing unit costs include fuel, fixed and variable operating costs. New units are also characterized by capital costs (CAP). A unit's fuel costs can be estimated by multiplying its average heat rate (MMbtu/MWh) and fuel price (\$/MMbtu). Fuel costs exist for all fossil and biofuel-fired units. All units have fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) costs. A unit's annual FOM cost equals its annual capacity multiplied by its per kilowatt (\$/kW) FOM cost. Within the utility data filings, FOM accounts for labor and other costs that are almost always fixed throughout a given year. A unit's annual VOM cost equals its per megawatt hour (\$/MWh) VOM multiplied by its annual generation. VOM accounts for costs that are proportional to usage, such as materials like lubricants. Capital cost includes construction and other costs (e.g. permitting) associated with building a new unit. We assume that operations and capital costs are constant through the model solution horizon, although a distinction is made between existing units and new units. We account for existing production tax credits as well as their expiration dates.

Costs represent only one part of a unit's data needs. The other involves its physical characteristics, such as heat rates for fuel-burning units and utilization rates. Units are unavailable to operate all hours in a year because they must undergo routine or emergency maintenance. When possible, "availability" is computed from data on historical operations. For units which have no readily accessible information, we estimate availability based on similar units provided within the IRPs.

"As available" units are subject to a capacity factor or utilization rate, which accounts for the physical limitations of these units (e.g., the sun does not shine and the wind does not blow 24 hours a day). For existing wind units, capacity factors are based on their 2010-2012 generation (EIA, 2010-2012b) where available, or are adopted from the 2013 IRP based on the site-specific wind resource (Hawaiian Electric Companies, 2013a; DOE, 2013). Capacity factors for new wind units are also from the 2013 IRP. In addition, based on Hawaii specific studies on

rooftop solar photovoltaic units, we use a capacity factor of 18% for existing units (HNEI, 2011; GE Consulting, 2012), and 23% for new units (HEI, 2013).

The initial capacity is provided as an input for all existing units. We assume that a unit can be retired from use if it ceases to be cost-effective. Oil-burning units can be modified to burn bio-oil, biodiesel or natural gas depending on the type of oil-burning unit. For diesel burning units, we assume biodiesel and conventional diesel are perfect substitutes. For fuel oil units, we assume the maximum share of bio-oil (or crude palm oil) that can be burned is 75%.

Table 3 provides an overview of the average costs and physical characteristics of existing and new units. HELM uses unit-specific figures. Electricity units are one of the following types: Internal Combustion (IC), Steam Turbine (ST), Gas Turbine (GT), Combined Cycle (CC), Combined Cycle Gas Turbine (CCGT), Simple Cycle (SC), Coal, Biomass, Municipal Solid Waste (MSW), Geothermal (Geo), Hydro, Wind, Wind with Battery Storage (Windbatt) Utility Scale Photovoltaic (PV), Utility Scale Photovoltaic with Battery Storage (PVbatt), and Rooftop Photovoltaic (Rooftop). We assume that ST, GT, CC, and SC units are able to burn conventional oil, bio-based oil, and natural gas. For a full description of the HELM model, see Appendix A.

Table 3. Cost and physical characteristics of existing and new units

	Total potential capacity GW (sum)	FOM \$/kW (avg)	VOM \$/MWh (avg)	Capital Exp \$/kW (avg)	Capital Cost \$/kW (avg)	Heat Rate MMBtu/MWh (avg)	Capacity Factor % (avg)	Availability % (avg)
Existing								
IC	0.18	66	14	-	-	9,769	-	34
ST	1.14	172	1	-	-	11,057	-	63
GT	0.31	45	16	-	-	17,501	-	11
CC	0.45	87	6	-	-	8,754	-	71
Coal	0.18	37	2	-	-	10,510	-	88
Biomass	0.01	170	5	-	-	10,011	-	80
MSW	0.09	263	18	-	-	15,932	-	60
Geo	0.04	162	19	-	-	-	-	90
Hydro	0.03	59	21	-	-	-	47	95
Wind	0.21	124	2	-	-	-	38	95
PV	0.02	42	22	-	-	-	22	95
Rooftop	0.24	-	-	1,384	-	-	18	95
New								
SC	No Limit	9	9	-	1,917	9,340	-	80
CC	No Limit	57	11	-	3,313	7,630	-	80
Gas (CCGT)	No Limit	58	7	-	3,110	7,660	-	80
Biomass	0.03	393	6	-	3,625	18,840	-	80
MSW ^b	0.06	568	31	-	17,195	19,300	-	83
Geo	0.08	190	27	-	8,751	-	-	90
Wind	0.39	214	2	-	3,868	-	39	95
Windbatt	0.39	213	2	-	4,476	-	39	95
PV	0.28	37	3	-	3,248	-	27	95
PVbatt	0.07	43	3	-	3,626	-	27	95
Rooftop	0.86	-	-	1,384	3,959	-	22	95

^aThis is the full cost before state and federal income tax credits (35% and 30%, respectively) are applied. Subsidies are accounted for within HELM.

^bWe assume that all new MSW is built and there is a minimum generation requirement imposed for both existing and new MSW capacity.

Sources: Data aggregated based on a weighted average (by capacity), from each island’s respective integrated resource plan, rate case filings, and the U.S. Energy Information Administration. Hawaiian Electric Companies, 2013a; HECO, 2005b; HECO, 2008; HECO, 2010; HELCO, 2006; HELCO, 2009; HELCO, 2012a; HELCO, 2012b; KIUC, 2008; KIUC, 2009; MECO, 2005; MECO, 2009; RSWG, 2013, EIA, 2010-2012a; EIA, 2010-2012b.

5.1.2 HCGE

H-CGE is a recursive dynamic general equilibrium model that projects from 2015 to 2040 in five-year increments. It is based on a Social Accounting Matrix developed with the 2007 State of Hawaii Input-Output (I-O) Study (2011). The benefit of a general equilibrium framework is that it shows interaction between consumers and producers, including price feedbacks (i.e. capturing “rebound effects”) and capital accumulation over time. H-CGE represents sector-level production for all sectors except electricity, which is represented in HELM.

A total of sixty-eight sectors are represented in the 2007 I-O table including electricity and petroleum manufacturing, as well as other energy-related sectors such as ground transportation, water transportation, and aviation. For the purposes of tractability in presentation, the sectors are aggregated to three: electricity, petroleum manufacturing, and “other.” Important agents of final demand include households, visitors, and federal and state governments.

On the production side, the 2007 State of Hawaii I-O Table provides the value of sector-level and value-added activity. In addition, it details the value of imports to each sector and the number of jobs. The following table, Table 4, provides a summary of the aggregate data used to calibrate H-CGE.

Table 4. Overview of Hawaii's Electric Sector in Relation to the Rest of the Economy

	Total Output ^a	Inter-Industry Demand	Imports ^b	Employee Income	Proprietor Income	Other Value-Added	Jobs ^c
	\$ 2007 Billion						#
Total	\$105.90	\$28.60	\$19.70	\$36.70	\$3.70	\$17.10	868,000
Electricity	2.10%	3.80%	2.10%	0.80%	0.00%	3.80%	0.30%
Petroleum Manufacturing	4.40%	10.6%	19.9%	0.20%	0.40%	1.10%	0.10%
Other Sectors	93.5%	85.6%	77.9%	99.0%	99.6%	95.1%	99.6%

^a The value of total output is equal to the summed value of inter-industry demand, imports, labor income, proprietor income and other value-added. These components provide a “production function” for each sector detailed within the I-O Table.

^b The value of “Imports” is not identical to the 2007 I-O Table because it is used to balance negative taxes to create a Social Accounting Matrix.

^c “Jobs” represents both the quantity of employee labor and proprietor labor. May not add to 100% due to rounding.

Hawaii's economy produces \$106 billion of output annually. There are 868,000 jobs, over half within service-related sectors. The state and local government is also a large employer, with 10% of jobs and 14% of wages paid. The electric sector accounts for 2% of overall economic activity and 0.3% of jobs. Petroleum manufacturing accounts for 4% of economic activity, where petroleum is the largest input into the electric sector (roughly 12 million barrels and equivalent to 693 million dollars (DBEDT, 2012). In 2007, \$3.9 billion was spent on imports into the petroleum manufacturing sector (i.e. the value of crude oil). This is 3.6% of the value of total economic activity.

Goods and services are consumed as intermediate inputs into the production of other industries, as well as by agents of final demand. Table 5 shows consumption of goods and services within Hawaii's economy by residents (households), visitors, state and local government, federal government, as well as the value that is put into investment and exported from the State.

Table 5. Overview of Hawaii's Final Consumption

	Household Demand	Visitor Demand	State and Local Gov ^a	Federal Gov ^b	Investment	Exports
	\$ 2007 Billion					
Total	\$42.20	\$14.60	\$7.70	\$9.80	\$12.60	\$4.70
Electricity	1.80%	0.00%	4.20%	0.40%	0.00%	0.00%
Petroleum Manufacturing	2.10%	0.10%	1.10%	0.90%	0.10%	11.6%
Other Sectors	81.5%	84.4%	87.7%	90.5%	70.3%	71.1%
Imports ^c	14.6%	15.5%	7.00%	8.10%	29.6%	17.4%

^a State and Local Government includes both investment and consumption

^b Federal Government includes both civilian and military, investment and consumption.

^c The value of “Imports” is not identical to the 2007 I-O Table because it is used to balance negative taxes to create a Social Accounting Matrix.

In the base year, residents consume \$42 billion of goods and services annually. The largest are for services (38%), real estate (20%) and imported products (15%). Residents spend \$753 million on electricity and \$891 million on petroleum products (primarily gasoline). Visitors, on the other hand, do not consume electricity “directly” (i.e. they are not customers of the electric utilities) but rather “indirectly” through hotel services and other amenities. Electricity is a large expense for State and Local government, at \$320 million annually and equivalent to 4% of all expenditures.

Baseline economic conditions in H-CGE are projected forward in time based on key assumptions about population growth. In addition, the *reference* fuel price pathway for oil (Brent) from the U.S. EIA's AEO 2013 (EIA, 2013d) are a main determinant of economic conditions.

5.2 Assumptions and Scenarios

This study assesses the electric sector and economy-wide impacts of importing LNG to Hawaii for use in the electric sector. We model four main cases. They are: 1) Baseline: where there is no gas introduced in Hawaii; 2) Low Gas Price Scenario: where natural gas follows a “low” price trajectory, as described in Figure 2; 3) Medium Gas Price Scenario; and 4) High Gas Price Scenario. In all cases, other fuels follow the *AEO 2013* reference fuel price forecasts (as described in Appendix A) and the RPS mandate is met. We also assume that there is no linking of the electric grid between islands.

In the three scenarios where Hawaii is allowed to import LNG, the model accounts for the in-state spending on construction for the LNG unloading and regasification facilities. The cost for the infrastructure to support LNG imports and gas distribution is assumed to be proportional to the amount of gas demanded by the electric sector. This cost ratio is based on the Galway scenario that estimates the cost to construct an FSRU facility to import 0.85 mpta of LNG. Multiplying this cost ratio times the amount of gas demanded by the electric sector yields the total construction cost. Only 40% of this cost is assumed to occur in-state. Much of the infrastructure would be fabricated and assembled outside of Hawaii and then transported to Hawaii for final assembly.

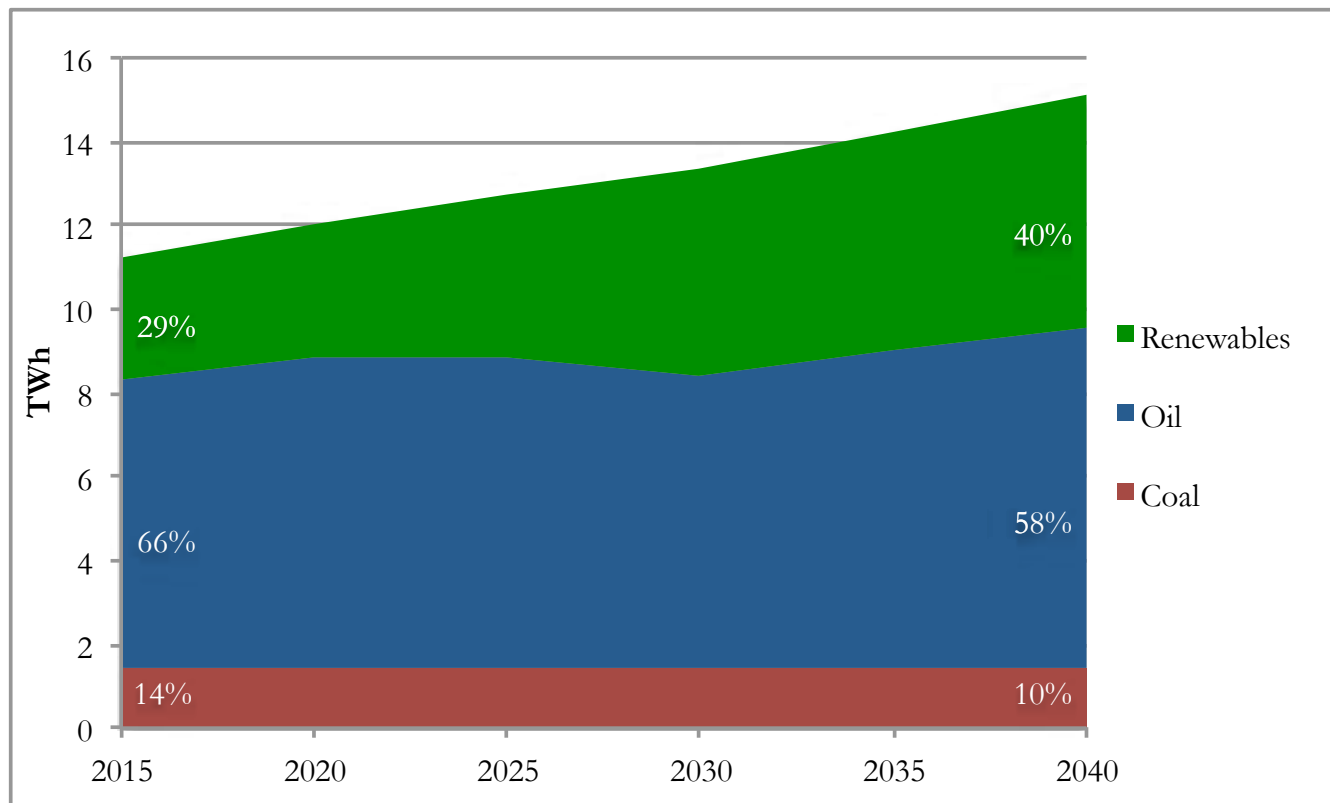
In sensitivity analysis, we run the same scenarios without the constraint of the RPS. This is to better understand the impact of using natural gas in the motivation to comply with the RPS goal and impact to renewable energy markets.

5.3 Results

5.3.1 Baseline

In the baseline, where no gas introduced to the system, we find that oil-based electricity generation declines from 66% in the year 2015 to 58% in the year 2040. Renewable sources of energy increase from 29% in 2015 to 40% in 2040 (meeting the RPS). Use of coal remains constant, as it is found to remain cost-effective and we do not allow it to increase (by assumption). Figure 5 below shows electricity generation by renewable sources of energy, oil and coal from 2015 to 2040.

Figure 5. Electricity Generation by Renewables, Oil and Coal, 2015-2040
Shares of Generation based on Sales⁸



The estimated baseline is subject to major assumptions within the model and as summarized in Table 3. Namely, we assume that there are no major grid upgrades or cables connecting the islands electricity grids. This dramatically reduces the amount of renewable sources of energy that are able to come onto the system due to constraints in capacity. To do a full economic analysis of potential grid upgrades is outside the scope of this study (and its limitations in interpreting results are discussed in our concluding section). However, this scenario provides a consistent baseline that provides a point of comparison to better understand the economic impacts of importing LNG for use in Hawaii’s power sector.

5.3.2 Introducing Natural Gas

We find that introducing natural gas in Hawaii has the potential to substantially reduce electric sector costs. In the case that natural gas prices are Low, we find a 25% reduction in electric sector costs in the year 2040. In the Medium case, a decline of 14% and, in the High case, a decline of 6%. A summary of changes to electric sector costs is shown in Table 6 below (as an aggregate 5-year cost per period).

⁸ The shares shown in Figure 5 are based on electricity sales, which is the unit of measurement for compliance with the RPS law. The difference between generation and sales account for transmission and distribution losses, which we here assume to be 8%. As such, the percentage shares shown for the years 2015 and 2040 do not add up to 100%.

Table 6. Impacts to Electric Sector 5-Year Costs

	2015	2020	20.25	2030	2035	2040
Baseline (\$ Billion)	12.2	13.8	11.4	12.6	14.8	15.9
	<i>% Change from Baseline</i>					
Low	0%	-24%	-10%	-14%	-20%	-25%
Med	0%	-19%	-3%	-6%	-9%	-14%
High	0%	-2%	-2%	-4%	-2%	-6%
	<i>Change from Baseline (\$ Billion)</i>					
Low	0.0	-3.3	-1.2	-1.8	-2.9	-3.9
Med	0.0	-2.6	-0.4	-0.8	-1.3	-2.2
High	0.0	-0.3	-0.2	-0.5	-0.3	-0.9

In the case that natural gas prices are Low, we find that electric sector costs could be reduced by nearly \$4 billion in the time period 2036-2040. For illustration, if electricity rates are \$0.34/kWh, as today, then a 25% reduction leads to a reduction in electricity rates by \$0.05/kWh, now \$0.29/kWh. The magnitude of savings clearly varies widely with fuel price being the largest determinant. If the price of natural gas is oil-linked, as in the High scenario, the savings is only \$0.1/kWh. If Hawaii cannot negotiate a gas-linked price, the higher oil-linked gas prices will severely erode cost savings.

We find that there should be a large-scale and rather abrupt switch from oil to LNG in the cases that prices are Low and Medium. In the case that prices are High, there should be a much more gradual adoption of LNG. Figures 6-8 below should the change in electricity generation from the baseline for the three gas price scenarios, for renewable energy, oil, coal and gas.

Figure 6. Change in Electricity Generation from Baseline, Low Gas Price

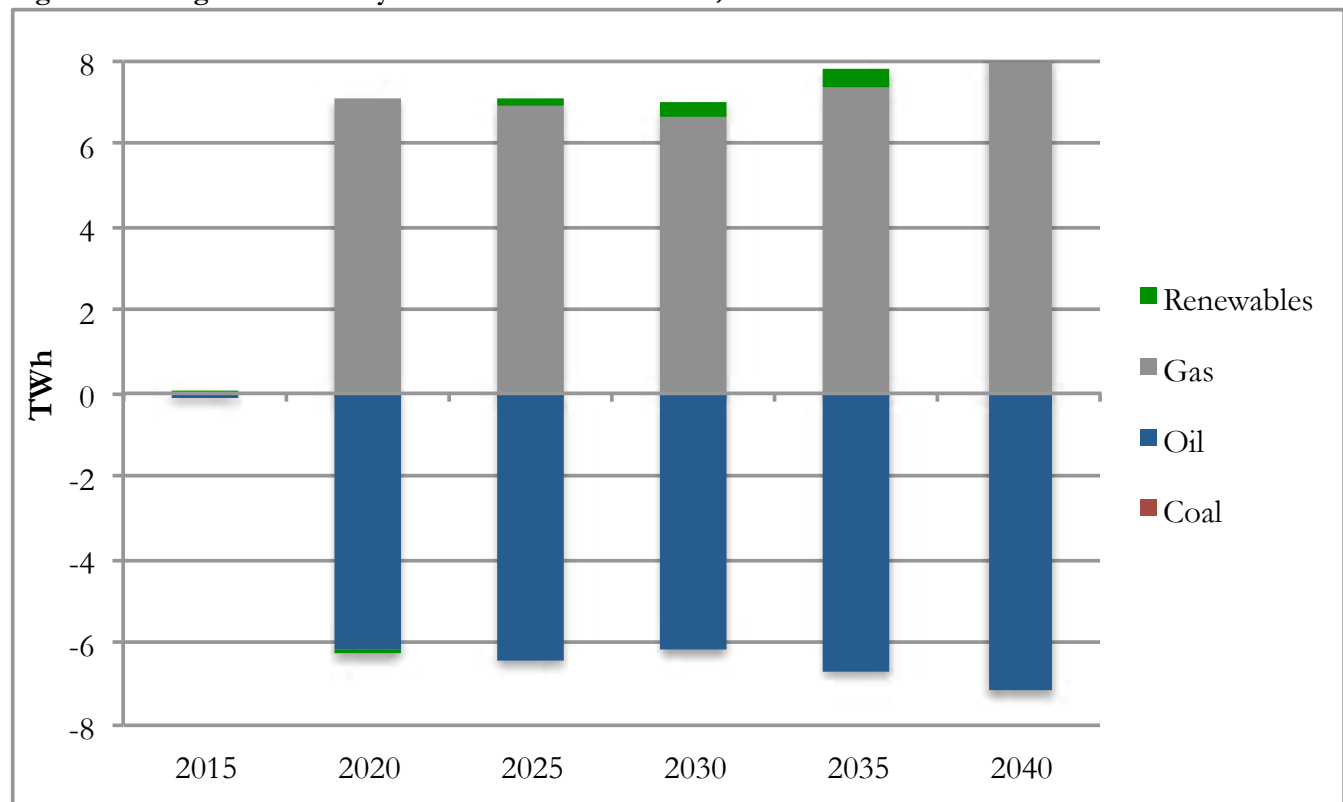


Figure 7. Change in Electricity Generation from Baseline, Medium Gas Price

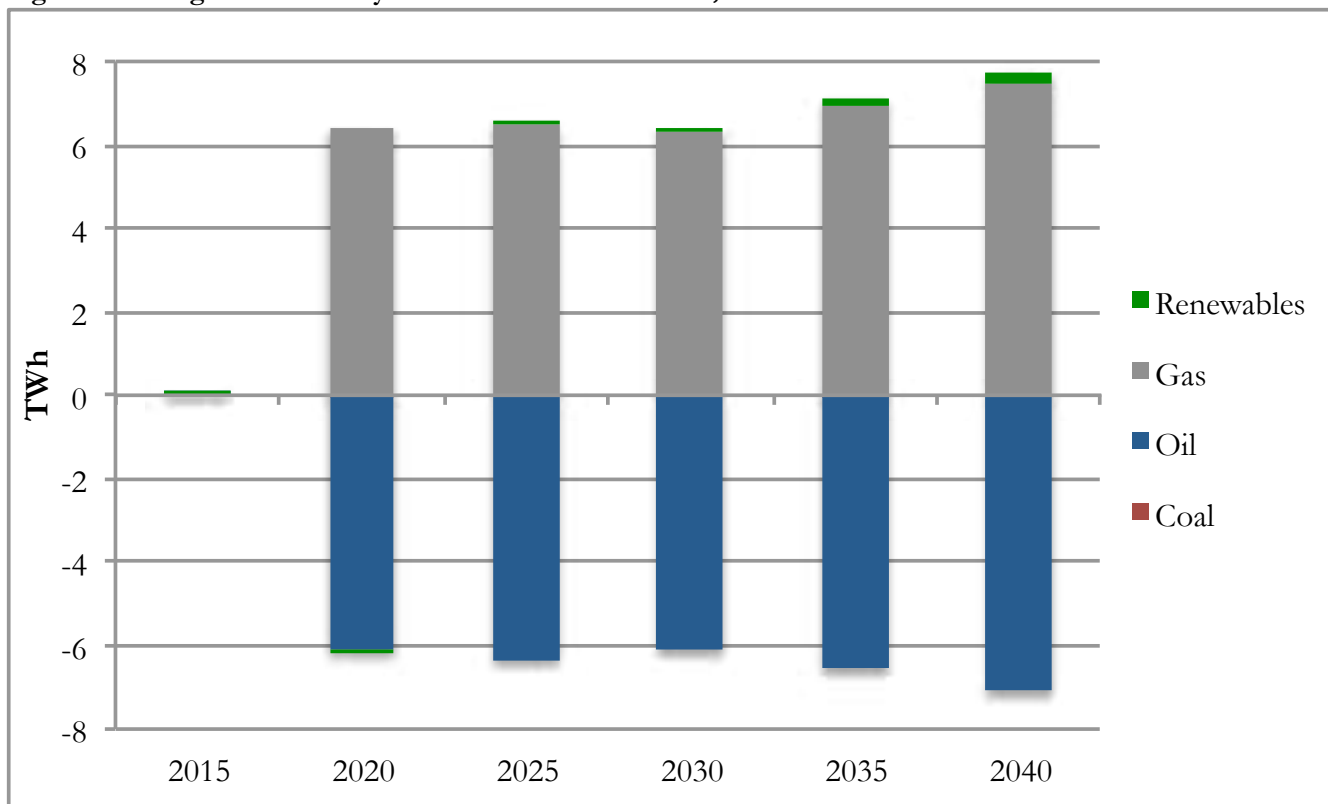
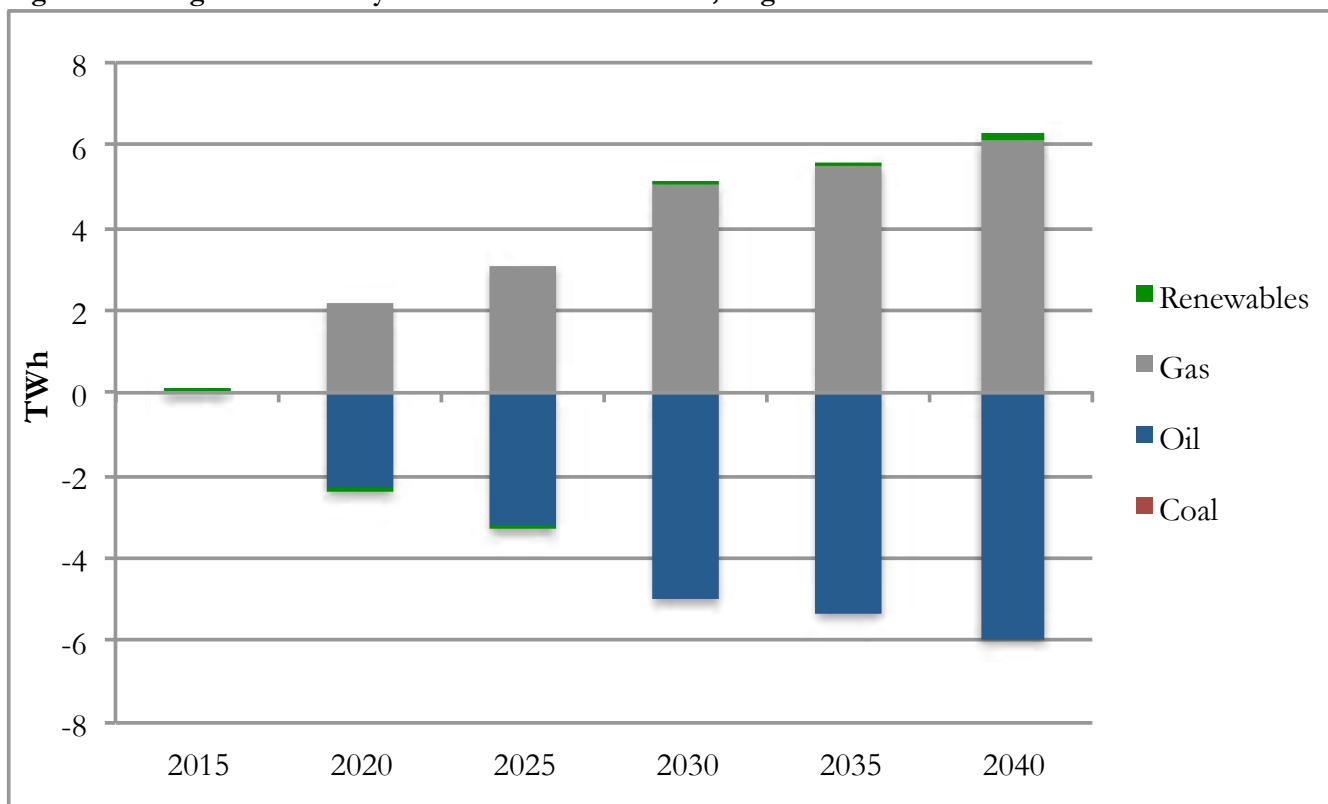


Figure 8. Change in Electricity Generation from Baseline, High Gas Price



Because introducing natural gas to the system reduces electricity costs and, by extension, rates, we find that there is a “rebound effect.” In the case that prices are Low, we estimate there is an 8% increase in electricity demand

(relative to the baseline) by the year 2040. This is 4% in the case that prices are Medium and 2% in the case that prices are High.

We also find that introducing natural gas can actually lead to an increase in the penetration of renewable sources of energy, where this effect increases as natural gas prices decline (and after the year 2020). The reason for this is in part because there is an increase in demand and so new sources of generation must be built. As a critical point of sensitivity, however, this finding does not hold when the RPS law is not enforced.

In the Low case, the model finds gas to be an extremely attractive option. In 2020, the model adds 460 MW of new gas-fired capacity and retrofits 650 MW of existing oil-fired units to burn gas (see Table 7). These capacity additions result in about 7.1 TWh of gas-fired generation in 2020, which is over 55% of total electricity generation. The amount of gas-fired generation climbs over time as new gas-fired generation is built. This new generation meets increases in load and displaces some gas-fired generation from existing, less efficient units.

Table 7. Gas-fired generation and New Gas-fired Capacity (Low Gas Price)

<i>Gas-fired Generation from Existing and New Units (TWh)</i>						
	2020	2025	2030	2035	2040	
Existing	3.9	3.4	2.6	2.7	2.7	
New	3.2	3.5	4.1	4.7	5.3	
Share from New	45%	51%	61%	64%	66%	
<i>New Gas-fired Generation Capacity (MW)</i>						
	2020	2025	2030	2035	2040	Total
New capacity	462	54	73	95	80	765

The Medium case has a similar profile of gas-fired generation and construction of new gas units as the Low case. The higher gas prices in the Medium case leads to about 10% less gas-fired generation from existing units than in the Low case and about 5% less capacity from new-gas fired units. Results are shown below in Table 8.

Table 8. Gas-fired generation and New gas-fired capacity (Medium Gas Price)

<i>Gas-fired Generation from Existing and New Units (TWh)</i>						
	2020	2025	2030	2035	2040	
Existing	3.6	3.2	2.5	2.5	2.5	
New	2.8	3.3	3.8	4.4	5.0	
Share from New	44%	51%	61%	64%	67%	
<i>New Gas-fired Generation Capacity (MW)</i>						
	2020	2025	2030	2035	2040	Total
New capacity	409	78	72	86	83	728

The gas prices in the High case lead to no switching from oil to gas in 2020 the perpetually higher gas prices result in about 40% less retrofitting of existing oil units than in the Low and Medium cases. By 2040, 15% less gas-fired generation is built than in the Low case. Thus the higher gas prices mainly delay the penetration of gas into Hawaii's electricity market. Results are shown below in Table 9.

Table 9. Gas-fired generation and New gas-fired capacity (High Gas Price)

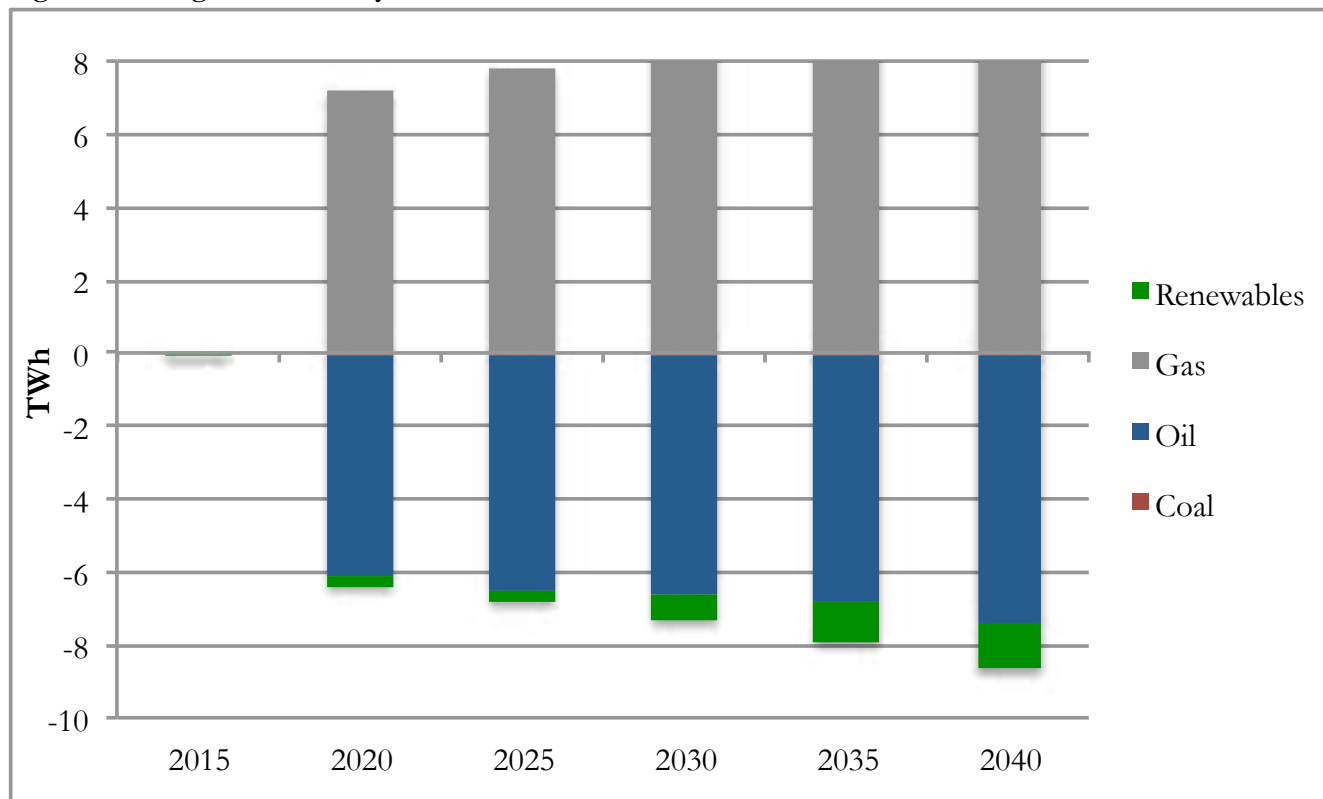
<i>Gas-fired Generation from Existing and New Units (TWh)</i>					
	2020	2025	2030	2035	2040
Existing	0.0	0.2	1.6	1.5	1.6
New	2.2	3.0	3.5	3.9	4.6
Share from New	100%	95%	69%	72%	75%

<i>New Gas-fired Generation Capacity (MW)</i>						
	2020	2025	2030	2035	2040	Total
New capacity	317	111	77	66	92	663

Because new CCGT units are much more efficient than existing generation units, there should be a relatively higher proportion of new units built when gas prices are High. This is because fuel is more costly and thus there is incentive to waste less fuel in more efficient units. Because more natural gas is introduced when fuel prices are Low, however, the overall amount of new capacity added is highest in this case.

Figure 9 below shows the change in electricity generation when natural gas prices are Low and the RPS is not enforced. Renewable energy declines, relative to its baseline, throughout.

Figure 9. Change in Electricity Generation from Baseline, Low Gas Price, No RPS



We find that natural gas is most likely to “push out” PV resources – though if the price of PV continues to fall, this finding may not hold.

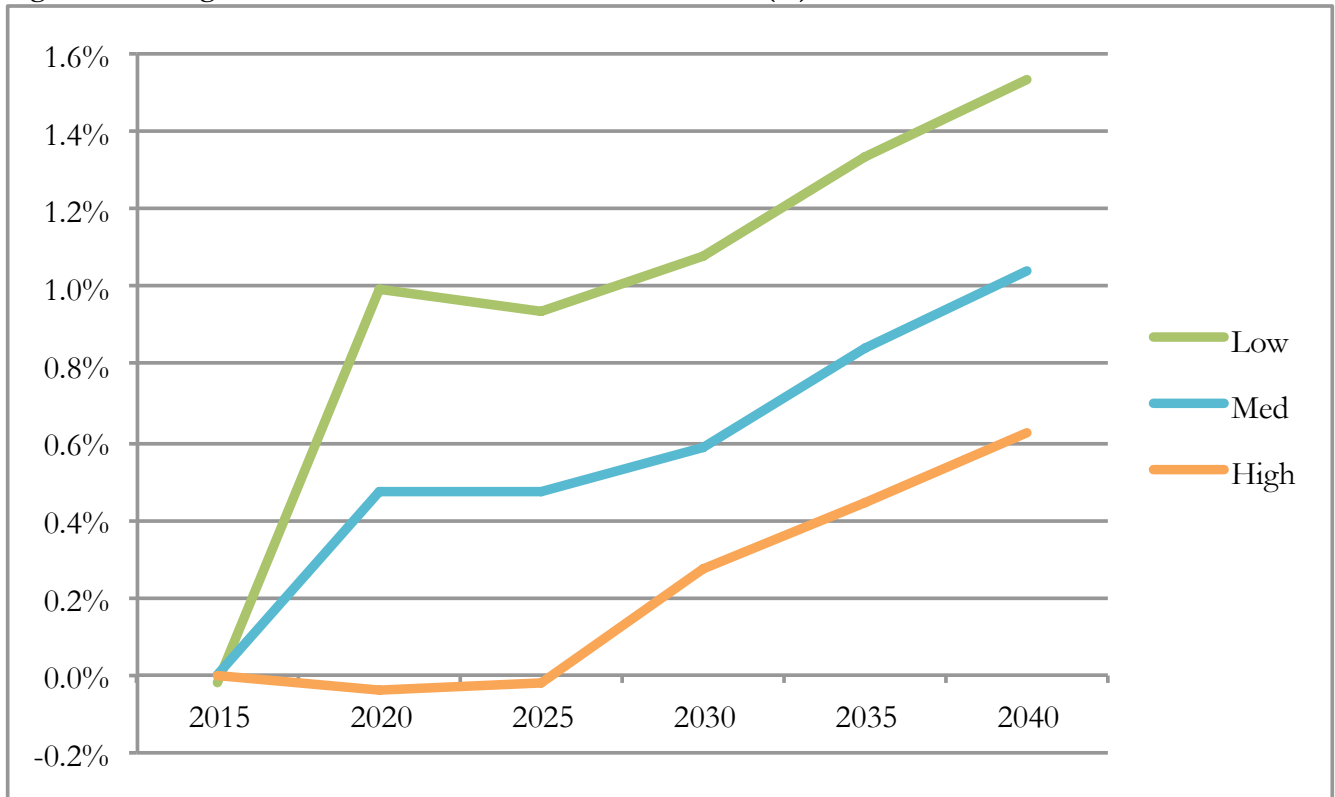
5.4 Economy-Wide Impacts

Gross State Product

The reduction in electric sector costs leads to a ripple effect throughout Hawaii’s economy. Though the electric sector accounts for about 2% total productivity, it is a sector that impacts all other sectors and thus can have

great aggregate effect. The lower cost of electricity, translated by decreased rates, lowers the cost of production in all sectors as well as the cost of providing services to visitors. These lower costs increase Hawaii's competitiveness and translate into an increase in Hawaii's gross state product (GSP). In addition, the investment in Hawaii's infrastructure (to allow for the import and regasification of LNG) also increases economic activity and GSP. Construction activities will also have an inflationary effect in terms of creating greater demand for the current supply of labor and other construction-related sectors. This effect is countered, however, by the decrease in electricity rates. Figure 10 below show the change in real GSP as a result of introducing natural gas in Hawaii's electric sector.

Figure 10. Change in Real Gross State Product from Baseline (%)

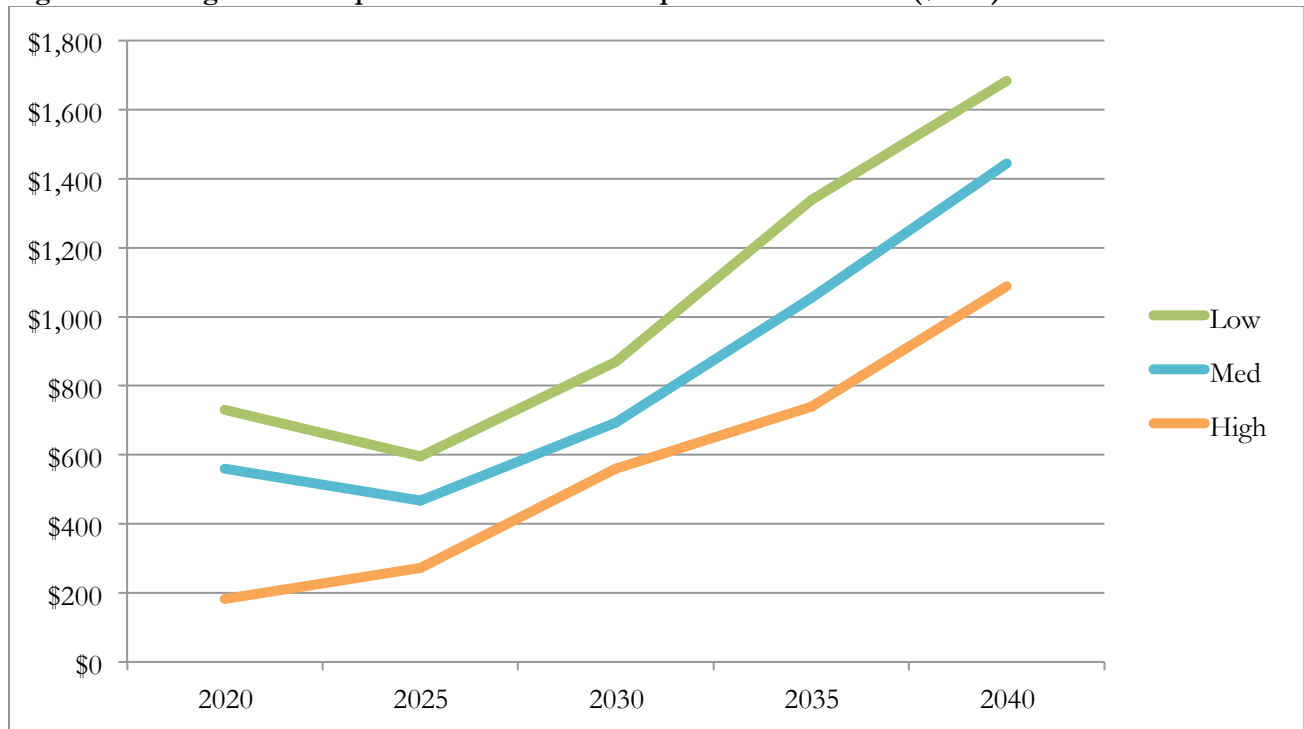


In all cases considered, there is an overall increase in real GSP relative to the baseline. In the case that natural gas prices are High, however, there is a near-term decrease in GSP due to the cost of capital and the relative expense of natural gas. In the Medium case, GSP is estimated to increase by slightly over 1% in the year 2040 and, in the Low case, by 1.5%. Given the small size of the electric sector relative to overall economic activity, this is a sizeable impact to the overall economy. Moreover, this impact is cumulative through the entire time period. Over the model horizon, the increase in GSP from the baseline when gas prices are Low has a net present value of \$11 billion (assuming a 4% rate of discount and \$2014). When gas prices are Medium, \$6.2 billion; and High, \$1.8 billion.

Household Income

Lower electricity prices means that households spend less on electricity and can therefore increase their consumption of other goods and services. This increase in consumption results in a general improvement in economic wellbeing for households. Figure 11 shows the change in household consumption as a result of introducing natural gas in Hawaii's electric sector.

Figure 11. Change in Per Capita Household Consumption from Baseline (\$2007)



The average household is able to increase the value of their consumption by a range of \$1,100 to \$1,700 per year by the year 2040. On average from 2020 to 2040, the representative household increases real consumption by \$1,000 annually when natural gas prices are Low, \$840 when they are Medium, and \$570 when they are High.

Petroleum Sector Impacts

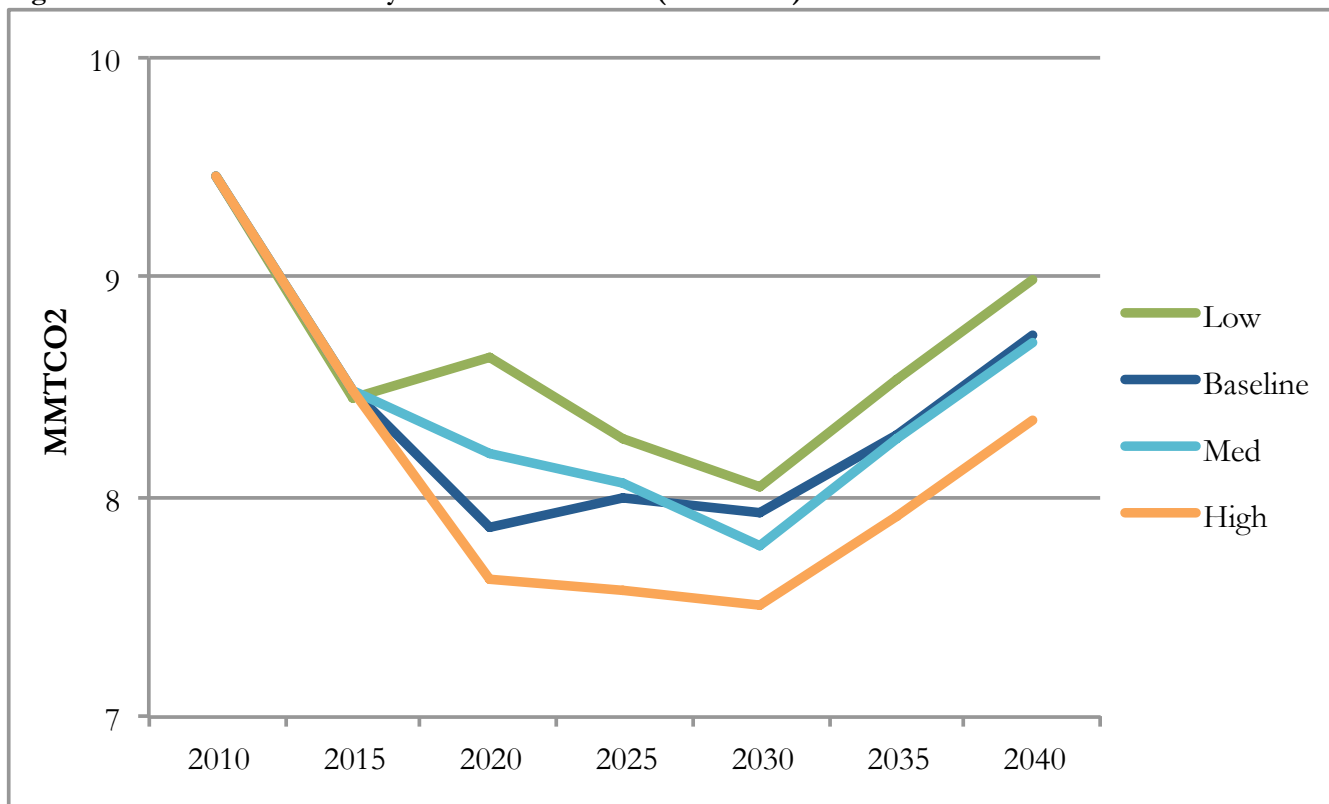
Importing LNG to Hawaii for use in the electric sector has the largest impact on the petroleum manufacturing sector. By the year 2040, the real value of output of the petroleum manufacturing sector declines by about 30% in each case. The impact to the sector over time varies, however, depending on the rate of LNG adoption. When LNG prices are Low and Medium, the real value of output in the petroleum manufacturing sector declines quickly, by 24% in the year 2025. When prices are High and LNG adoption is more gradual, it is an estimated 14% impact to the petroleum manufacturing sector. The electric sector, on the other hand, increases its output because of the increase in electricity demand.

These results do not take into account any rigidity in production output within the petroleum manufacturing sector as well as do not delve into issues of refinery shut-down.

5.5 GHG Impacts

Using natural gas in the electric sector serves to drive down out-of-stack GHG emissions in Hawaii but can also lead to “leakage,” where upstream GHG emissions are gained elsewhere. We find that introducing natural gas increase lifecycle GHG emissions, except in the High price case. Lifecycle GHG emissions impacts are shown in Figure 12.

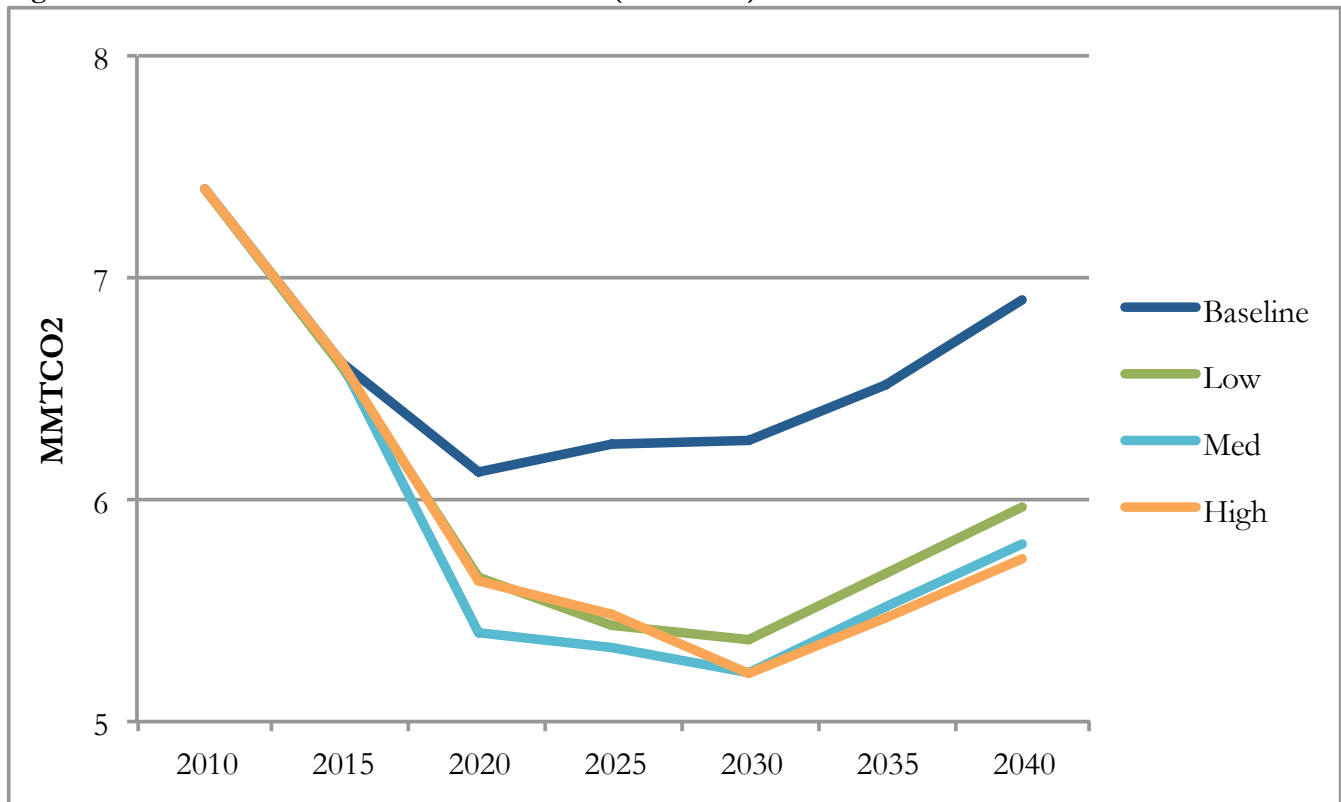
Figure 12. Electric Sector Lifecycle GHG Emissions (MMTCO₂)



Our estimates of lifecycle emissions are primarily based on the GREET model. However, our review of literature shows that there is large disparity in GHG emissions calculations due to differences in location as well as study methodology. For example, if Hawaii is importing refined products from the mainland or Canada, then lifecycle GHG emissions for natural gas are likely to rise with increasingly more crude oil coming from oil sands in Canada and fracking within the continental U.S.

If considering only out-of-stack emissions (as required by the State of Hawaii’s GHG emission reduction rules for the electric sector), then introducing natural gas lowers electric sector emissions in all cases. Estimated out-of-stack GHG emissions are shown below in Figure 13.

Figure 13. Electric Sector Stack GHG Emissions (MMTCO₂)



Because natural gas burns far more cleanly than oil, GHG emissions reduce substantively within the electric sector in all cases. There is also a counter effect due to the rebound of electricity demand in response to lower prices. This is why GHG emissions in the Low case are not substantively better than in the High case.

6. Discussion and Conclusions

We find that Hawaii importing natural gas to be used in the power sector could lower costs of electric generation and benefit Hawaii's economy. Though this finding generally holds through the entire range of LNG prices considered, it is particularly impactful when prices range between the Medium and Low price estimates (i.e. are gas-linked). When prices are High, there is a near-term negative impact on gross state product due to the cost of capital relative to the return on the investment from the gas infrastructure that must be built to support the importing of LNG and distribution of gas. Thus careful consideration must be given to the sourcing of LNG including terminal siting options, otherwise the possible economic and GHG benefits may not be realized.

In the Low and Medium cases there is a dramatic shift away from oil and immediate adoption of gas in the year 2020. In the High case, gas penetrates the market much more gradually with gas initially being burned in only new dedicated gas-fired units. In all cases, however, petroleum manufacturing output declines by approximately 30% by the year 2040. This will have impact to the petroleum refineries operations, though understanding specific outcomes are outside the scope of this analysis.

We additionally find that if the State's RPS remains in force, introducing LNG does not serve to displace sources of renewable energy within Hawaii, as currently priced. On the other hand, if the State's RPS were relaxed, we find that importing LNG can reduce the amount of renewable energy adopted within the market, particularly when natural gas prices are Low. In particular, natural gas crowds out solar PV. This finding, however, is subject to our assumptions about the cost of renewable generation to that of gas-fired generation. If the cost of solar PV continues to decline rapidly, natural gas may not displace it even under low gas prices. We also find that when natural gas prices are Low, existing coal-fired generation could be displaced. This suggests that LNG is quite cost-effective relative to all existing technologies. As such, if LNG is adopted, it is unlikely to serve as a "bridge fuel" unless strong policies protecting renewable energy adoption are enacted and/or enforced. In addition, lower natural gas prices

drive down electricity rates and lead to more demand for electricity, which makes energy efficiency measures relatively more costly causing less energy efficiency to be undertaken by consumers.

Using natural gas in the electric sector serves to drive down out-of-stack GHG emissions in Hawaii but can also lead to “leakage,” where upstream GHG emissions increase elsewhere. The omission of hydraulic fracturing from strict environmental regulations and scrutiny have led to the EPA revisiting regulatory requirements regarding impacts to water resources. The form of future regulations in regards to GHG emissions and water resources could dramatically impact the availability of natural gas in the U.S. and hence raising its price.

Study Limitations

This study has several major limitations in terms of assumptions and scope. First, this study does not provide a full analysis of alternative investments that could be made in the electric sector to meet future demand. Specifically, further analysis should be done in regards to the economic impacts of making large-scale investments in the grid including storage options that dramatically changes the usable capacity of intermittent sources of renewable energies. Second, this study considers only one oil-price forecast and one set of costs for new technologies: this analysis assumes that oil prices increase and prices of renewable energy remain constant. This means that renewable sources of energy become more favorably priced over time. Other forecasts for oil prices are less dramatically increasing than the *AEO 2013* reference case (for example, the newly released *AEO 2014* reference case). However, it is also likely that costs of renewable energy continue to decline. While this study estimates impacts to the petroleum manufacturing sector, it does not explore the possibility of a “shut-down.” The last major limitation is that this study does not address issues of risk and timing in investing in infrastructure relative to the procurement of fuel.

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Appendix A. HELM

HELM is a detailed “bottom-up” representation of Hawaii’s electricity sector. HELM is calibrated to existing electricity units in the year 2013 (\$2007) for Hawaii’s four counties: the City & County of Honolulu, Maui County, Kauai County, and Hawaii County. HELM is a fully dynamic linear program model (i.e. a partial equilibrium representation of the electricity sector for the State) that solves for the least cost mix of generation to satisfy demand while complying with system operating conditions and environmental policies. It optimizes decisions over the 2010-2030 timeframe in five-year time steps. The system of constraints and the objective function of HELM are based on Martin Ross’s Electricity Markets Analysis (EMA) model (Ross, 2008) and ICF’s Integrated Planning Model (IPM) (EPA, 2008).

HELM is modeled in GAMS, which allows it to have an extremely flexible structure so that one can easily expand the model’s dimensions such as number of technologies and time periods. The remainder of this section details the model’s objective function and constraints.

Objective function

The objective function represents the discounted present value of the costs of generation: fuel costs, fixed and variable operating and maintenance costs, and capital costs of new units.

$$\begin{aligned}
 z = e = & \sum (t, DF(t)) \\
 & * \left(\sum ((f, g, b), FuelPrice(f, t) * HeatRate(g, f) * Gen(g, f, b, t)) \right. \\
 & + \sum ((f, g, b), VOM(g) * Gen(g, f, b, t)) + \sum ((f, g,), FOM(g) * Cap(g, f, t)) \\
 & + \sum ((f, g), CapCost(g) * Bld(g, f, t)) \\
 & \left. + \sum ((f, g) \$RePwrF(f), RePwrCst(g) * Bld(g, f, t)) \right)
 \end{aligned}$$

(A.1)

Where the sets $t, g, f,$ and b are defined:

t = time periods, g = generators, f = fuels, and b = load blocks.

Where the parameters $DF, FuelPrice, HeatRate, VOM, FOM, RePwrCst, RPwrF,$ and $CapCost$ are defined:

$DF(t)$ = Discount factor ($DF(2010) = 1$)
 $FuelPrice(f, t)$ = Price of fuel, f , in year t
 $HeatRate(g, f)$ = Heat rate for unit g burning fuel f (MMBtu/MWh)
 $VOM(g)$ = Variable operating cost of unit g (\$/MWh)
 $FOM(g)$ = Fixed operating cost of unit g (\$/kW)
 $RePwrCst(g)$ = Cost to repower unit g with alternate fuel (\$/kW)
 $RPwrF(f)$ = Indicator of which fuel can be used to repower
 $CapCost(g)$ = Capital cost to build a new unit (\$/kW).

Where the variables $Cap, Gen,$ and Bld are defined:

$Gen(g, f, b, t)$ = Generation of unit g using fuel f in load block b during year t (TWh)
 $Cap(g, f, t)$ = Capacity of unit g used to burn fuel f (GW)
 $Bld(g, f, t)$ = Capacity of new unit g built to burn fuel f in year t (GW).

Constraints

Combined with the objective function, the electric system defined in HELM is governed by the following constraints. To account for each unit's typical operation throughout the year, HELM can impose maximum and minimum capacity utilization constraints on a unit's operation:

$$\sum (f, Gen(g, f, b, t)) = G = MinCapFac(g, b) * BlkHr(b) * \sum (f, Cap(g, f, t)) \quad (A.2)$$

$$\sum (f, Gen(g, f, b, t)) = L = MaxCapFac(g, b) * BlkHr(b) * \sum (f, Cap(g, f, t)) \quad (A.3)$$

These constraints are denoted in units of generation. The minimum and maximum utilization rates remain constant over an individual year and from year to year. Because some units can burn multiple fuels, the model must ensure that the sum of the capacities used for each unit does not exceed its total capacity.

$$MaxCap(g, t)Sum(f, Cap(g, f, t)) = L = MaxCap(g, t) \quad (A.4)$$

HELM targets an exogenous demand projection and forces total generation to meet demand on each of the four major systems. The demand forecast represents end-use demand while generation measures output of each generator to the grid. Therefore, the demand constraint must account for transmission losses to deliver power from the generators to the end-users.

$$\sum ((g, f), Gen(g, f, b, t)) * (1 - TrnLoss(p)) = G = \sum (c, Demand(c, p, b, t)) \quad (A.5)$$

Where:

p = The set of power pools (HECO, HELCO, KIUC, and MECO)
 $TrnLoss(p)$ = Average power loss from transmission by power pool (assumed to be 8%).

For all systems, the Hawaii PUC requires the utility systems to have enough reserve capacity on-line at all times to meet demand and account for any contingencies. HELM's reserve margin constraint represents this requirement. It ensures that the sum of all available capacity times one plus the reserve margin requirement exceeds the peak generation in the year.

$$\sum ((f, g)$(mapg2p(g, p)), Cap(g, f, t) * (1 - derate(g))) = G = (1 + ReserveMargin(p)) * PeakDemand(p, t) \quad (A.6)$$

Where:

$mapg2p(g, p)$ = Mapping of generators to power pools
 $ReserveMargin(p)$ = Reserve margin requirement by power pool (equal to 15%)
 $PeakDemand(p, t)$ = Peak demand for power pool p in year t (GW).

HELM also requires a reserve margin be met for each load block. This constraint requires for each load block that all available capacity (i.e., capacity on-line and not down for maintenance) exceed one plus the reserve margin requirement times generation.

$$\sum ((g$map2p(g, p), BlkHr(b) * \sum (f$(mapf2g(f, g)), Cap(g, f, t)))) - Mnt(g, b, t) = G = (1 + OperRM(p)) * \sum ((f, g)$(mapf2g(f, g)andmapg2p(g, p), Gen(g, f, b, t)))$$

(A.7)

To account for decisions to build new capacity, retrofit existing units, or retire capacity, HELM has two constraints that track the transition of capacity from one time period to the next. The first constraint initializes the capacity in the first endogenous model year (i.e., 2010); and the second constraint tracks the evolution of the capacity of each unit.

$$Cap(g, f, t) = E = Cap0(g, f) + Bld(g, f, t) * CapCost(g) - Ret(g, f, t) \quad (t=2010) \quad (A.8)$$

Where:

$CapCost(g)$ = Cost to build capacity for unit g

$Ret(g, f, t)$ = Variable that denotes amount of retirement of unit g using fuel f in year t (GW).

For all model years after the first year:

$$Cap(g, f, t) = E = Cap(g, f, t - 1) + Bld(g, f, t) * CapCost(g) - Ret(g, f, t) \quad (A.9)$$

HELM includes constraints to represent Hawaii's current RPS mandates. This constraint is active only if RPS targets are put in place in the scenario modeled.

$$\sum ((f, g, b, p) * mapg2p(g, p))$$

and

$$mapp2rps(p, rps), RPSCredit(g, f) * Gen(g, f, b, t) = G = RPSTgt(rps, t) * Sum((f, b, g) * Gen(g, f, b, t)) \quad (A.10)$$

Where:

$mapp2rps(p, rps)$ = Mapping of power pools to RPS regions (i.e., under the current RPS regulations, HECO, HELCO, and MECO would be mapped to one RPS region representing the HECO utility)

$RPSCredit(g, f)$ = Percentage of unit g 's generation using fuel f that counts toward the RPS requirement

$RPSTgt(rps, t)$ = RPS target in year t for RPS region rps .

The HELM model represents emission caps and emission rates for the GHG CO₂. Though it could be expanded, currently HELM's emission constraints account only for CO₂ and are active only if an emissions target or emissions rate is specified for CO₂. These constraints can account for either out-of-stack or lifecycle emissions of all units or subsets of units, where lifecycle emissions are shown in Table A1.

Equation (11) represents the emissions cap constraint; and Equations (12a) and (12b) represent the emissions rate constraint. The emissions rate constraint is a proxy for what might result from the EPA's proposed new source performance standards (NSPS) for electric generators. At the time of this report, the EPA has not decided whether NSPS will be applied unit by unit (equation (12a)) or if it can be applied for a collection of units (equation (12b)).

$$\sum ((f, g, b) * (mapf2p(f, g) * EmisRate(f, "TpMMBtu")), EmisRate(f, "TpMMBtu") * HeatRate(g, f) * Gen(g, f, b, t)) + \sum ((f, g, b) * (EmisRate(f, "TpKWh") * mapg2type(g, "ZC")), EmisRate(f, "TpKWh") * Gen(g, f, b, t)) = L = EmisRateTgt(t) * \sum ((f, g, b) * mapf2g(f, g), Gen(g, f, b, t)) \quad (A.11)$$

$$\sum((f, b), EmisRate(f, "TpMMBtu") * HeatRate(g, f) * Gen(g, f, b, t)) \leq EmisRateStandard(t) * \sum((f, b,), EmisRate(f, "TpMMBtu") * HeatRate(g, f) * Gen(g, f, b, t)) \quad (A.12a)$$

$$\sum((f, g, b) \$fossil\ unit(g), EmisRate(f, "TpMMBtu") * HeatRate(g, f) * Gen(g, f, b, t)) \leq EmisRateStandard(t) * \sum((f, b,), EmisRate(f, "TpMMBtu") * HeatRate(g, f) * Gen(g, f, b, t)) \quad (A.12b)$$

Where:

$EmisRate(f, "TpMMBtu")$ = Emissions rate for fuel f (metric tons of CO₂/MMBtu) for combustion units

$EmisTgt(t)$ = Emissions target for CO₂ (millions of metric tons)

$EmisRate(f, "TpKWh")$ = Emissions rate for non-combustion units (metric tons of CO₂/kWh).

Table A1. Lifecycle GHG Emissions Factors (kg CO₂/kWh and MTCO₂/MMBtu)

	Mine to Plant	Plant + Combustion	Total (kg CO ₂ / kWh)	Total (MTCO ₂ / MMBtu)
Oil	0.013	0.085	-	0.098
Coal	0.005	0.109	-	0.11
Natural Gas	0.037 ^a	0.053	-	0.090
Geo	0.00	0.017	0.017	-
Wind	0.00	0.007	0.007	-
Solar PV	0.00	0.076	0.076	-
Other	-	-	0.53	-

^aIncludes CH₄ and CO₂

Source: Estimates from GREET model (Argonne National Laboratory, 2010; Argonne National Laboratory, 2014). NETL, 2014.

Intermittent generation sources such as wind and solar do not produce a firm or completely predictable source of power. These sources vary with weather conditions, which are unpredictable. This unpredictability leads to instability in the electricity grid as the share of generation from intermittent sources rise. It is still an open question as to at what level problems appear. For this analysis, HELM assumes that intermittent generation cannot exceed 20% of total generation at any point in time. Therefore, HELM specifies by load block the maximum allowable level of intermittent generation on each island.

$$\begin{aligned} &MaxAsAvail(p, t) * \\ &\sum((f, g) \$ (mapg2p(g, p) and, mapf2g(f, g)), Gen(g, f, b, t)) \geq \\ &\sum((f, g) \$ (mapg2p(g, p) and, mapf2g(f, g) and, (Windg(g) or, Solrg(g)))) Gen(g, f, b, t) \end{aligned} \quad (A.13)$$

Where:

$MaxAsAvail(p, t)$ = Maximum fraction of as-availables (or intermittent sources).

All units need to undertake maintenance and repair during the year. Also, there is often unplanned maintenance that must take place. The following constraints require each unit to be off-line for a minimum of a specified number of hours each year. The time off-line accounts for planned maintenance and forced outages.

$$\sum(b, Mnt(g, b, t)) \geq \left(1 - \frac{GenDat(g, "EA")}{100}\right) * 8.76 * \sum(f \$ mapf2g(f, g), Cap(g, f, t)) \quad (A.14)$$

Where:

$Mnt(g,b,t)$ = TWh of generation unable to deliver because of maintenance requirement
 $GenDat(g,"EA")$ = Equivalent availability as a %.

Depending on the scenario, the model allows for the building of new coal units. The price forecasts that HELM uses for coal, from the EIA, lead to the total lifecycle cost of coal fired generation being far less than existing generation. Therefore, the HELM mathematically wants to replace all existing fossil generation with new coal units. However, this fails to reflect considerations such as ability to secure capital to build new units, permitting, and demand on resources (e.g., land and labor). Therefore, a constraint is imposed on the capacity of new coal that can be built over time. HELM constrains new coal units such that there can be no new units in the years 2010 and 2015, up to 150MW in 2020, and can increase in increments of 50MW in 2025 and periods beyond. Moreover, because of the size of coal units, it is assumed that a new coal unit would only be built on Oahu.

Given the current restrictions on grid-connected rooftop solar PV, HELM assumes an introduction rate for rooftop solar. In addition, the model includes maximum capacity limits by Island for PV: 600 MW for Oahu, 120 MW for Hawaii, 90 MW for Maui, and 50 MW for Kauai.

The model also includes restrictions on new coal-fired generation. In most cases, the amount of new coal-fired generation is fixed at zero. For the few scenarios that allow new coal, the amount that can come on-line is 200 MW in 2020 and then 50 MW per five years henceforth.

Appendix B. H-CGE and Integration with HELM

The Hawaii Computable General Equilibrium Model (H-CGE) is an economy-wide computable general equilibrium (CGE) model of Hawaii's economy. It reflects activity in 68 sectors and 11 agents of final demand including households, visitors, state and local government, as well as federal government. It is integrated with HELM in respect to the electric sector, as described in Bohringer and Rutherford (Bohringer and Rutherford, 2008).

Production of Non-Energy Sectors

Production in the economy is represented through a nested-Leontief function. At the first level, a Leontief production function represents final output (Y_j) in sector $j=1,..,n$ as made up of intermediate inputs (Z_{ij}) of commodity $i=1,..,n$, and energy/value-added (EV_j). Final output of sector j and intermediate input of commodity i include all sectors with the exception of energy (petroleum manufacturing and electricity):

$$Y_j = \min \left[\frac{Z_{1j}}{\alpha_{1j}} \dots \frac{Z_{nj}}{\alpha_{nj}}, \frac{EV_j}{\alpha_{vj}} \right] \quad (\text{B.1})$$

where α_{ij} , α_{vj} are unit input coefficients for intermediates and energy/value-added respectively.

At the second level, intermediate inputs consist of flexible domestically-produced and importable commodities represented through an Armington⁹ constant elasticity of substitution (CES) production nest:

$$Z_{ij} = \left[\theta_{Dij} D_{ij}^{\frac{\varepsilon_{ijm}-1}{\varepsilon_{ijm}}} + \theta_{Mj} M_j^{\frac{\varepsilon_{ijm}-1}{\varepsilon_{ijm}}} \right]^{\varepsilon_{ijm}/(\varepsilon_{ijm}-1)} \quad (\text{B.2})$$

where ε_{ijm} is the CES substitution between domestically-produced good i and imports by producer j . ε_{ijm} takes the value 1.0. D_{ij} is what producer j demands of sector i for domestically-produced goods and M_j is the composite import good demanded by sector j . The parameter shares are represented by θ_{Dij} and θ_{Mj} , respectively.

For the energy/value-added (EV_j) nest, energy sectors (E_j) are represented as substitutable with value-added (V_j):

$$EV_j = \left[\alpha_{Ej} E_j^{\frac{\sigma_{EVj}-1}{\sigma_{EVj}}} + \alpha_{Vj} V_j^{\frac{\sigma_{EVj}-1}{\sigma_{EVj}}} \right]^{\sigma_{EVj}/(\sigma_{EVj}-1)} \quad (\text{B.3})$$

where σ_{EVj} is the CES among energy and value-added variables and α_{Ej} , α_{Vj} are the respective parameter shares. takes the value 0.5.

Value-added consists of capital (K_j) and labor (L_j), where labor is a composite of wage labor and proprietor income:

$$V_j = \left[\alpha_{Lj} L_j^{\frac{\sigma_{Vj}-1}{\sigma_{Vj}}} + \alpha_{Ej} E_j^{\frac{\sigma_{Vj}-1}{\sigma_{Vj}}} \right]^{\sigma_{Vj}/(\sigma_{Vj}-1)} \quad (\text{B.4})$$

⁹ The "Armington assumption" states that goods are differentiated by country of origin and is often used in regional CGE models to account for cross-hauling in trade data and to preclude unrealistic extreme specialization within countries. See Armington (1969).

where σ_{Vj} is the CES among value-added variables and α_{Lj} , α_{Kj} are the respective parameter shares. σ_{Vj} takes the value 1.0.

Labor (L_j) is a composite between wage labor (W_j) and proprietor income (R_j), which are, represented in a Leontief relationship:

$$L_j = \min \left[\frac{W_j}{\alpha_{Wj}}, \frac{R_j}{\alpha_{Rj}} \right] \quad (\text{B.5})$$

where α_{Wj} , α_{Rj} are unit input coefficients for wage labor and proprietor income respectively.

Energy sectors include electricity (EL_j) and petroleum manufacturing (PM_j) such that:

$$E_j = \left[\alpha_{ELj} EL_j^{\frac{\sigma_{Ej}-1}{\sigma_{Ej}}} + \alpha_{PMj} PM_j^{\frac{\sigma_{Ej}-1}{\sigma_{Ej}}} \right]^{\sigma_{Ej}/(\sigma_{Ej}-1)} \quad (\text{B.6})$$

where σ_{Ej} is the CES among energy sector variables and α_{ELj} , α_{PMj} , are the respective parameter shares. σ_{Ej} takes the value 0.2.

The initial endowment of wage labor, proprietor income, and capital ($\bar{W}_0, \bar{R}_0, \bar{K}_0$) are given within the baseline dataset. In calibration, the value of the initial endowment of wage labor, proprietor income and other value-added must equal the sum of each factor over all j industries

$$W = \bar{W}_0 = \sum_j W_j \quad (\text{B.7})$$

$$R = \bar{R}_0 = \sum_j R_j \quad (\text{B.8})$$

$$K = \bar{K}_0 = \sum_j K_j \quad (\text{B.9})$$

Output commodity Y_j can either be consumed domestically or exported and, under the Armington assumption, is differentiated for those markets using a constant elasticity of transformation (CET) function between domestic (D_j) sales and exports (X_j):

$$Y_j = \left[\beta_{Dj} D_j^{\frac{\varepsilon_j-1}{\varepsilon_j}} + \beta_{Xj} X_j^{\frac{\varepsilon_j-1}{\varepsilon_j}} \right]^{\varepsilon_j/(\varepsilon_j-1)} \quad (\text{B.10})$$

where ε_j is the elasticity of transformation and β_{Dj}, β_{Xj} are parameter shares. ε_j equals 5.0.

Production of Petroleum Manufacturing

The production of the petroleum manufacturing sector is assumed to be somewhat more “rigid” than other sectors. Specifically, the production of petroleum manufacturing output (i.e. refined petroleum products) is assumed to be a nested Leontief structure, with the exception of the value-added nest (which takes the form of Cobb-

Douglas). This means that there is ability to upgrade capital stocks to alter sector output. Otherwise, without capital upgrades, refinery technology is such that inputs are taken in fixed proportions. In addition, for the purpose of the EIA oil price scenarios, the value of imports into the petroleum manufacturing sector is assumed to be crude oil.

Production of Electricity

The electric sector is defined in detail within HELM. Thus the electric sector within H-CGE acts as a “placeholder” (within the representative agent endowment block) in which results from HELM are used as inputs to produce new equilibrium conditions.

In terms of H-CGE’s output being used as input into HELM, H-CGE provides the dynamic projection of baseline electricity demand for the State under the three EIA oil price scenarios. To more accurately represent demand over time, an exogenous electricity efficiency parameter is used to represent gains in both technology and federal programs (which are not endogenous to H-CGE). The parameter is estimated using EIA data on residential energy intensities and economy-wide efficiency parameters (energy per GDP) over time (EIA, 1999). The figure is taken to be a 0.8% annual efficiency gain.

The production function for electricity represented in H-CGE is distinct from other models. It is modified from Ross (2007) in the way that energy and value-added are treated. It did not seem appropriate to assume a substitution between capital and labor (as is common practice) for this sector because the tradeoff is really between existing electricity generation and new electricity generation (i.e. oil and capital).

Household Consumption

Household consumption, at the first level, is represented by a Cobb-Douglas utility function between transportation (TC) and other consumption (OC):

$$U = [\rho_{TC} TC^{(\sigma-1)/\sigma} + \rho_{OC} OC^{(\sigma-1)/\sigma}]^{\sigma/(\sigma-1)} \quad (B.11)$$

where U is the utility level, TC is consumption of transportation, and OC is the consumption of other goods; ρ_{TC} , ρ_{OC} are the resident income expenditure share on transportation and other consumption, respectively; and σ is the CES parameter, taking a Cobb-Douglas form (value of 1).

Within other consumption (OC), households consume both energy goods (EH) and non-energy goods (C):

$$OC = [\theta_{EH} EH^{\frac{\sigma_{OC}-1}{\sigma_{OC}}} + \theta_C C^{\frac{\sigma_{OC}-1}{\sigma_{OC}}}]^{\sigma_{OC}/(\sigma_{OC}-1)} \quad (B.12)$$

where EH is the energy consumption of households, and C is the consumption of other goods; θ_{EH} , θ_C are the parameter shares, respectively; and σ_{OC} is the CES parameter, taking the value of 0.25.

Households consume energy goods in the form of electricity (EL) and gas (GS):

$$EH = [\theta_{EL} EL^{\frac{\sigma_{EH}-1}{\sigma_{EH}}} + \theta_{GS} GS^{\frac{\sigma_{EH}-1}{\sigma_{EH}}}]^{\sigma_{EH}/(\sigma_{EH}-1)} \quad (B.13)$$

where EL is the electricity consumption of households, and GS is the gas consumption of households; θ_{EL} , θ_{GS} are the parameter shares, respectively; and σ_{EH} is the CES parameter, taking the value of 0.1.

Residents flexibly consume both domestically-produced goods ($i=1, \dots, n$) and an imported composite good (m):

$$C_i = [\theta_{Di} D_i^{\frac{\varepsilon_M - 1}{\varepsilon_M}} + \theta_M M^{\frac{\varepsilon_M - 1}{\varepsilon_M}}]^{\varepsilon_M / (\varepsilon_M - 1)} \quad (\text{B.14})$$

where ε_M is the Armington CES between domestically-produced good i and imports m , taking the value of 1.0. is resident demand for domestically-produced good i and M is imported demand. The parameter shares are represented by θ_{Di} and θ_M , respectively.

For transportation consumption, households consume purchased transportation (PT) and private transportation (i.e. private vehicles, “cars,” represented through the purchase of gasoline) (CR):

$$EC = [\theta_{PT} PT^{\frac{\sigma_{TC} - 1}{\sigma_{TC}}} + \theta_{CR} CR^{\frac{\sigma_{TC} - 1}{\sigma_{TC}}}]^{\sigma_{TC} / (\sigma_{TC} - 1)} \quad (\text{B.15})$$

where PT is the consumption of purchased transportation by households,¹⁰ and CR is the consumption of gasoline (and diesel) for ground transportation; θ_{PT} , θ_{CR} are the parameter shares, respectively; and σ_{TC} is the CES parameter, taking the value of 0.1. This level of detail is provided within the household sector because the oil price scenarios will greatly impact household transportation patterns.

Household Budget Constraint

A representative resident’s expenditure constraint can be written as:

$$\sum_i p_i C_{ri} + p_m C_m = p_W W + p_R R + p_K K + \bar{p}_{fx} BP - T_r \quad (\text{B.16})$$

where prices p_i represent the market prices for commodities $i = 1, \dots, n$ and p_m is the price of imports. C_{ri} is resident consumption of good i and C_m is the consumption of imported goods. The resident derives income from factors of production including wage labor (W), proprietor income (P), and capital (K), where p_W , p_R , and p_K are the market price of the respective factors. The resident pays a lump-sum tax (T_r), net of transfer payments, to the State and Local Government. The resident also receives foreign exchange ($\bar{p}_{fx} BP$) from a balance of payment deficit, described below.

Visitors

Visitor consumption is represented through a simple Cobb-Douglas utility function:

$$U_v = \left[\sum_i \rho_{vi} C_{vi}^{\frac{\sigma_{vi} - 1}{\sigma_{vi}}} + \rho_{vm} C_{vm} \right]^{\sigma_{vi} / (\sigma_{vi} - 1)} \quad (\text{B.17})$$

where U_v is the visitor utility level, C_{vi} is consumption of domestic goods and services, C_{vm} is the consumption of imported goods, and ρ_{vi} and ρ_{vm} are the visitor income expenditure share on commodities $i = 1, \dots, n$ and imports, respectively. σ_{vi} is the CES parameter, taking a Cobb-Douglas form (value of 1).

¹⁰ Including air transportation, water transportation, trucking, bus transit, and sightseeing transportation.

Because visitors do not provide labor or earn income within Hawaii, a representative visitor's income (I_v) is taken to be exogenous:

$$I_v \stackrel{\text{def}}{=} I_{v0} = \sum_i p_i C_{vi} + p_m C_{vm} \quad (\text{B.18})$$

where I_{v0} is the initial visitor expenditure.

Government

Government activity is represented through the State and Local Government (SG) and the Federal Government (FG). Each government type purchases domestic commodities (G_{gi}) and imports (G_{gm}) according to a Leontief utility function to assure a constant level of public provision:

$$U_g = \min [G_{g1}, \dots, G_{gn}, G_{gm}] \quad (\text{B.19})$$

where $g = SG, FG$.

The State and Local Government depends entirely on the economy for the tax base:

$$\sum_i p_i G_{SLi} + p_m G_{SLm} = \sum_i p_i Y_i \tau_i + T_r \quad (\text{B.20})$$

where p_i and p_m are the price of commodities $i=1, \dots, n$ and imports, respectively. Thus the left-hand side represents the cost of public expenditures. These expenditures are funded primarily through the State's general excise tax (τ_i) on producer output (Y_i) of commodity i . The State and Local Government also impose a variety of taxes (T_r), such as property and income taxes on residents.

The market clearing conditions must hold such that the cost of public expenditures balances government income.

$$\sum_i p_i G_{gi} + p_m G_{gm} = I_{g0} \stackrel{\text{def}}{=} I_g \quad (\text{B.21})$$

Balance of Payments

A balance of external payments (BP) is maintained under the assumption of a fixed exchange rate (\bar{p}_{fx}), where \bar{p}_{fx} is the exchange rate with the "rest of the world." This assumption is made because Hawaii uses the U.S. dollar as a means of currency and, as a small economy, has no effect on the exchange rate. The quantity of imports (M) is constrained by the inflow of dollars obtained from visitor expenditures (I_v), Federal Government expenditures (I_{FG}), and Hawaii exports (X_j). Because Hawaii is a price taker, import and export prices are exogenous.

$$\bar{p}_{fx} BP = \bar{p}_m M - I_{FG} - \sum_j \bar{p}_{xj} X_j \quad (\text{B.22})$$

Market Clearing

Constant returns to scale and perfect competition ensure that the producer price (p_j) equals the marginal cost of output in each sector j . In addition, the State and Local Government collects a general excise tax (τ_j) on sales. This implies that the value of total output (supply) equals producer costs, where p_W , p_R , and p_K equal the market price of labor, proprietor income, and capital respectively.

$$p_j Y_j (1 + \tau_j) = \sum_{i=1, \dots, n} p_i Z_{ij} + p_W W_j + p_R R_j + p_m M_j \quad (\text{B.23})$$

In addition, sector j output, which supplies to the domestic market (D_j), is demanded by households and visitors $a \in \{h, v\}$ and government $g \in \{SG, FG\}$, and industries $Z_i = 1, \dots, n$.

$$D_j = \sum_a C_{aj} + \sum_g G_{gj} + \sum_i Z_i \quad (\text{B.24})$$

In equilibrium, the value of output balances the value of inter-industry, consumer, and government agencies demand.

Elasticity Values

Table B.1 provides the elasticity values used within H-CGE, provided above, and documented with a source where available.

Table B.1. Model Elasticity Values and Source

Elasticity Between:	Value	Source
Domestic Consumption & Exports	5	Konan & Kim (2005); Ross (2007) uses 3.0
Non-Energy Sector Production		
Energy/Value-Added & Intermediate Inputs	0	Ross (2007), standard assumption
Energy & Value-Added	0.5	Ross (2007)
Electricity & Oil	0.2	Ross (2007) uses 0.5, adjusted downwards
Capital & Income	1	Ross (2007), standard assumption
Wage Income & Proprietor Income	0	Assumes fixed relationship between proprietors and labor
Domestic Goods & Imported Goods	1	Armington Assumption, Cobb-Douglas
Petroleum Manufacturing Sector		
Value-Added & Intermediate Inputs	0	Leontief Production, standard assumption
Capital & Income	1	Ross (2007), standard assumption
Wage Income & Proprietor Income	0	Assumes fixed relationship between proprietors and labor
Domestic Goods & Imported Goods	0	Armington assumption, Leontief due to rigid technology
Electricity Sector		
Value-Added & Intermediate Inputs	0	Leontief Production, standard assumption
Domestic Goods & Imported Goods	0.3	Ross (2007)
Wage Income & Proprietor Income	0	Assumes fixed relationship between proprietors and labor
Capital & Oil	0.5	Assumed flexibility to allow for investment ^a
Household Consumption		
Transportation & Other Consumption	1	Ross (2007)
Energy Goods & Non-Energy Goods	0.25	Ross (2007)
Electricity & Gas	0.1	Ross (2007) uses 0.4 for general "energy", adjusted down
Purchased & Private Transportation	0.1	Ross (2007) uses 0.2, but HI has few public transit options
Other Goods and Services	0.5	Ross (2007)
Domestic Goods & Imported Goods	1	Konan & Kim (2005)
Visitor Consumption		
Consumption Goods	1	Konan & Kim (2005)
Government		
Public Expenditures	0	Konan & Kim (2005)

^aThis elasticity is not (known to be) cited within the literature because it represents a new structure presented in H-CGE that is adopted to better capture the tradeoff between current oil-burning electricity generators and investment in new units.

Elasticity values primarily follow the ADAGE model, a global (multi-country, multi-region) energy-CGE model developed by Martin Ross and documented in Ross (2007). In addition, figures are adopted from previous Hawaii-specific CGE modeling platforms, documented in Konan and Kim (2005). Leontief production functions (CES=0) and Cobb-Douglas preferences (CES=1) are generally standard CGE assumptions, as special cases of CES production and utility functions.

Dynamic Calibration

H-CGE is a recursive-dynamic model, based in the year 2007 and projecting in five-year intervals between the year 2010 and 2030. The primary driver of overall economic growth is an exogenous parameter based on Hawaii's historic growth rate, g , of 2.2% annually (11.6% growth rate over five years). This is calculated from historic

estimates of real Gross State Product, 1977 to 2008¹¹ (DBEDT, 2010). Capital accumulation is endogenous within the model, meaning that investment in one period leads to new capital stock in the next:

$$p_K K_{t+1} = (1 - \delta)(p_K K_{t-1} + p_K K_t) \quad (\text{B.25})$$

$$p_K K_t = (r + \delta)(p_{INV} INV_{t-1}) \quad (\text{B.26})$$

where δ is the capital depreciation rate and r is the rate of return on investment. The rate of return, r , is assumed to take the value of 5% annually (27.6% over five years) and δ is calibrated such that it is consistent with the overall growth rate, g , and r , given initial values of capital and investment provided in the benchmark dataset:

$$INV_0 = \frac{(\delta + g)p_K K_0}{(\delta + r)} \quad (\text{B.27})$$

where δ is calculated to take the value of 1.0% annually (5.1% over a five-year time period).^{12,13}

Other drivers of economic growth, such as labor, visitor expenditures, and the balance of payments, are assumed to grow exogenously at the steady-state growth rate g :

$$p_W W_{t+1} = (1 + g)p_W W_t \quad (\text{B.28})$$

$$p_R R_{t+1} = (1 + g)p_R R_t \quad (\text{B.29})$$

$$\bar{p}_{fx} BP_{t+1} = (1 + g)\bar{p}_{fx} BP_t \quad (\text{B.30})$$

Model Linking

Figure B.1 highlights the linkage between the H-CGE and HELM models. This section describes the three points in the solution process in which the two models communicate with each other.

In the first instance, the H-CGE model passes the baseline level of electricity demand to the HELM model. The H-CGE model reads in an exogenously specified oil price forecast, and then solves for a baseline solution without any input from the electricity sector and hence with the electricity sector treated like all other industrial sectors in the model. After H-CGE finds an equilibrium solution, it passes the resulting level of electricity demand for Hawaii to the HELM model.

HELM reads in this equilibrium level of electricity demand and uses this time series to define statewide electricity demand. Since HELM solves for generation for the four major islands, Hawaii, Kauai, Maui, and Oahu, the statewide demand is divided into four demands based on each island's historical share of statewide electricity demand.

¹¹ Gross Domestic Product was formerly called Gross State Product.

¹² See Paltsev (2004) for documentation. This assumes an investment on a steady-state.

¹³ In future iterations of H-CGE, this assumption will be checked for sensitivities to model outcomes.

HELM then solves for the least cost mix of generation given this level of demand for each island. HELM then passes back to the macro model the statewide quantity of resources used to produce electricity. These include labor, capital, materials, and energy (biofuels, coal, and oil).

H-CGE reads in these results and fixes the level of inputs into the electricity sector at these levels. H-CGE is then resolved for the baseline assuming this level of resources are used in electricity production. In finding the new baseline equilibrium, the model solves for the new prices for all goods and services including those for the electricity sector. This concludes the baseline solve.

Next, the models solve under the described scenarios. First HELM is solved to determine the least-cost generation mix while complying with the RPS policy. In the scenario solve, HELM is solved as a quadratic program. The non-linearity accommodates the linear demand function for electricity and thus electricity demand within HELM is allowed to respond to the RPS policy. The values of the inputs into the electricity sector are summed across the four islands to provide the level of inputs at for the entire state. H-CGE reads in these inputs and solves in similar fashion to how it solves its baseline. Figure B.2 graphically describes this process.

Figure B.2: Linkage between HCGE and HELM

