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Cost Implications of GHG Regulation in Hawai'i

by

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List of Acronyms

AEO	Annual Energy Outlook
BC	black carbon
CAP	capital costs
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CAA	Clean Air Act
CC	combined cycle
DOH	Department of Health
EEPS	Energy Efficiency Portfolio Standard
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOM	fixed operating and maintenance
GT	gas turbine
GAMS	General Algebraic Modeling System
Geo	geothermal
GWh	gigawatt hour
GWP	global warming potential
GHG	greenhouse gas
GREET	The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
HCEI	Hawaiʻi Clean Energy Initiative
HELM	Hawaiʻi Electric Model
HFCs	hydrofluorocarbons
IC	internal combustion
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
LCA	life cycle analysis
CH_4	methane
MWh	megawatthour
MT	million tons
MMT	million metric tons
MWC	municipal waste combustion
MSW	municipal solid waste
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
N_2O	nitrous oxide
PFCs	perfluorocarbons
PUC	Public Utilities Commission
RPS	Renewable Portfolio Standard
Rooftop	Rooftop photovoltaic
SC	simple cycle
ST	steam turbine
SF_6	sulfur hexafluoride
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

The State of Hawaiʻi and the U.S. are developing greenhouse gas (GHG) emissions reduction regulations in parallel. The State requires that economy-wide GHG emissions be reduced to 1990 levels by the year 2020 and the U.S. Environmental Protection Agency is developing new source performance standards (NSPS) for new electricity generation units. The State Department of Health has proposed rules that would reduce existing large emitting electricity generating units by 16% from 2010 levels. The NSPS proposes GHG concentration limits for new electricity units.

We use a comprehensive model of Hawaiʻi's electricity sector to study the potential cost and GHG impacts of State and Federal GHG regulations. Given uncertainty about the final form and implementation of these regulations, we adopt a series of scenarios that bracket the range of possible outcomes. First we consider the State's GHG cap (for existing units) and NSPS (for new units) being implemented at the facility level. Next, we consider the implications of allowing for partnering to meet the State GHG cap and the NSPS at a system-wide level. We also consider the case where the State GHG cap is extended to apply to both existing and new units. The current proposed State GHG rules exclude biogenic sources of emissions. We address the impacts of this decision through sensitivity analysis and explore the impact of GHG policy on new coal-fired units.

We find that regulating GHGs at the facility level leads to greater reductions in GHG emissions but at higher cost. Over the 30-year period that we study, when biogenic sources of emissions are ignored, facility-level implementation of policy will add $3 billion to the cost of electricity generation at an average cost of $180/ton of GHG abatement. If biogenic sources of emissions are included within the accounting framework, abatement costs rise to $340/ton.

When policy allows for greater flexibility by allowing for system-wide partnering, GHG targets are achieved at a much lower cost that does not differ substantively from baseline conditions (with no GHG restrictions), assuming fuel prices follow the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO) *2013*'s *reference* case. This is true for both the case of system-wide partnering and application of the NSPS as well as for an extended State GHG cap with system-wide partnering. The ability to partner between facilities, akin to a system of tradable permits, allows for flexibility in meeting either a cap or concentration limit at least cost. In the first, the flexible policy imposes virtually no additional cost to the electric sector and, in the second, a cost-effective $5/ton. There would be outside management and coordination costs associated with regulation of emissions, which are not here considered.

Our results regarding changes in biofuel generation based on inclusion of biogenic emissions are driven by the fact that biofuels are relatively expensive. Assuming the aim of policy is to reduce GHG emissions as cost effectively as possible, and biofuels remain more costly than their fossil fuel counterparts, then bio-based generation is not widely adopted when policy allows for flexible system-wide partnering. However, the imposition of GHG rules at a facility level leads to increased incentive for adoption of biofuels though a partial repowering of existing oil-fired generators. Moreover, we find that including lifecycle biofuel emissions within policy can actually lead to the counter-intuitive result that bio-based generation increases. In contrast, if biofuel prices are lower than the price of oil, then biofuels are adopted in the baseline case.

There is currently no law explicitly prohibiting the introduction of new coal units, though the largest utility voluntarily agreed to refrain from building or purchasing from any new coal units. As a sensitivity analysis, we assess whether the GHG rules, particularly Federal, will prohibit the introduction of new coal. We find that no new coal (or oil) units can be introduced if the NSPS is implemented at a facility level. However, if policy is implemented at the system level, a large amount of new coal could still be built and meet the overall GHG intensity standard. Though this serves to drive down electricity generation costs, overall GHG emissions rise substantively and any future abatement efforts become considerably more costly. Moreover, current versions of the NSPS suggest that it will be implemented either at the facility level or between fossil-fuel units. In these outcomes, new-fired units will be prohibited.

DOH's proposed rules do allow for partnering among affected units. However, there is uncertainty in terms of implementation because agreements are accepted *at the discretion of the director*. If facilities fail to partner and/or proposals are not supported by the DOH, the outcome will be more like facility-level implementation.

Overall, we find that the high cost of Hawai'i's current electricity generation provides a strong incentive to move towards less costly alternatives – in this consideration, primarily wind and rooftop PV. This leads to a reduction in GHG emissions. However, this finding would not hold if fuel prices were substantively lower than current levels, either from falling prices or fuel-switching to lower cost products. Regardless, the qualitative implications about the optimal structure of GHG policy are robust to changing assumptions about fuel prices. Implementing GHG policy at the facility level leads to relatively higher levels of GHG emissions reductions, though at substantially higher cost. If a greater level of GHG emissions reduction is desired, the least cost policy is to lower the level of the GHG cap while still allowing for the greatest flexibility in achieving targets.

I. Introduction

This study analyzes the impact of the State of Hawai'i's and U.S.'s pending greenhouse gas (GHG) emissions regulations on Hawaii's electric sector. The analysis considers different potential implementations of the regulations. This document first provides a history of U.S. and Hawai'i climate change policies. Next it describes the Hawai'i Electric Model (HELM) that is used to assess the policy impacts. An outline of the key scenarios based on a range of policy outcomes follows this section. Last this document presents results and draws conclusions.

II. Background

Climate Change Overview

During the 1970s, scientists became concerned about the impact of anthropogenic release of GHGs into the earth's atmosphere. By the late 1970s, researchers and scientists started to identify links between GHG emissions, primarily carbon dioxide (CO_2), and global temperature increase. The creation of the Intergovernmental Panel on Climate Change (IPCC) in 1988 established a global forum for international cooperation and a stimulus to begin research in earnest (IPCC, n.d.). By the mid-1980s, it became apparent that the problem of GHG emissions and accelerated climate change was of unprecedented global scale. Although similar in many ways to the problem of ozone depletion, GHG's pose vastly more complex problems in terms of scientific understanding, economic implications, cultural change, and political solutions (Carlarne, 2010).

A mix of six GHGs - carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) - contribute to anthropogenic climate change (U.S. EPA, 2010a). These gases trap heat in the atmosphere, causing the planet to warm; their contribution to warming, also known as global warming potential (GWP) differs based on the length of time they remain in the atmosphere, and how much energy they absorb (U.S. EPA, 2013a).

- **Carbon dioxide (CO_2)** - Combustion of fossil fuels is the primary source of CO_2 emissions. CO_2 is also released in the production of cement. The way in which people use land is also an important source of CO_2, especially deforestation.

- **Methane (CH_4)** - Agricultural activities, waste management, and energy production/use, such as production of natural gas, contribute to CH_4 emissions.

- **Nitrous oxide (N_2O)** - Agricultural activities, such as fertilizer use, are the primary source of N_2O emissions.

- **Fluorinated gases (F-gases)** - Industrial processes, refrigeration, and the use of a variety of consumer products contribute to emissions of F-gases, which include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6).

Black carbon (BC) is a solid particle or aerosol—not a gas—but it also contributes to warming of the atmosphere (U.S. EPA, 2013a).

The IPCC's *Fifth Assessment Report on Climate Change 2013* states that human influence on the climate system is clear and unequivocal. It concludes that humanity must not exceed the earth's "carbon budget." The carbon budget describes how much carbon dioxide (or equivalent) people can continue to emit into the atmosphere. With at least a 66% probability of remaining within two degrees Celsius, cumulative carbon emissions from 1861-1880 are not to exceed 1,000 gigatons of carbon (IPCC, 2013).

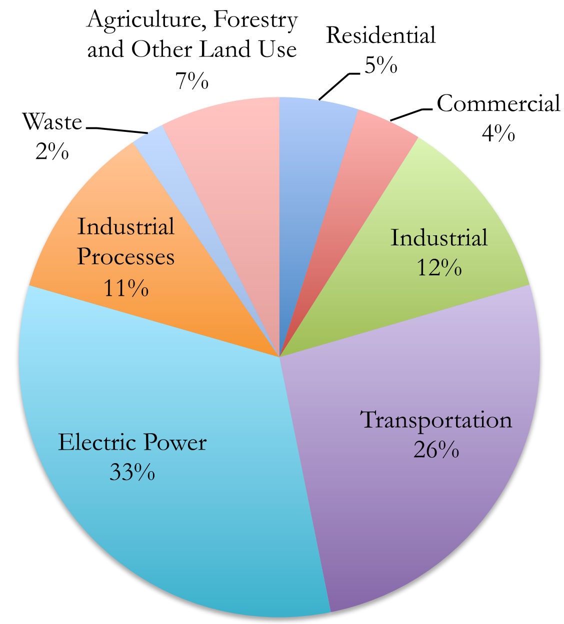
By 2011, more than half - 531 gigatons – have already been emitted. According to economist Lord Stern, half to two-thirds of the carbon budget is already exhausted based on the existing IPCC's assessment; and if the release of emissions continues in a business as usual scenario, the world will exhaust the budget within the next 15 to 25 years (Harvey, 2013).

Overall, CO_2 accounts for about 77% of the global anthropogenic GHG emissions. In 2010, 33.4 billion metric tons or 91% of CO_2 emissions came from the burning of fossil fuels and cement production. The remaining 3.3 billion metric tons or 9% comes from deforestation and land use change (Friedlingstein et al., 2010). Fifty percent of CO_2 released by human activities accumulates in the atmosphere, 26% is absorbed back into land as a carbon sink, and the world's oceans absorb the remaining 24% (CO2Now.org, 2007-2014).

U.S. Climate Change Policies and Programs

The U.S. is the second largest emitter of CO_2, next to China, and by far the largest on a per capita basis. While global CO_2 emissions averages 4.4 metric tons per capita, U.S. per capita emissions totaled 15.7 metric tons, followed by Europe (6.8 metric tons per capita) and China (6.5 metric tons per capita) (Joint Research Centre, 2012). India, Russia, and Japan have also consistently ranked amongst the top emitters (U.S. EPA, 2013b; Joint Research Centre, 2012). In 2011, the U.S. economy generated 6,700 $MMTCO_2e$. Figure 1 highlights U.S. GHG emissions by activity (excluding sinks).

Figure 1. U.S. GHG Emissions by Activity



Total US GHG Emissions 2011: 6,702 MMTCO2E

Source: U.S. EPA, 2013c.

Environmental Protection Agency and the Clean Air Act

In 1963, the creation of the Clean Air Act (CAA) established funding for the study and cleanup of air pollution (U.S. EPA, 2012b). In 1970, Congress passed a stronger version of the CAA to regulate air pollution that endangers "public health and welfare," and created the Environmental Protection Agency (EPA) to set standards and manage new environmental legislation. In 1990, Congress further revised and expanded the CAA, providing EPA with even broader authority to implement and enforce regulations to reduce emissions of air pollutants (U.S. EPA, 2012b). The 1990 Amendments also placed an increased emphasis on a more market-based structure and cost-effective approaches to improve urban air quality. Under the CAA, EPA sets limits on 188 air pollutants to ensure basic health and environmental protection from air pollution (U.S. EPA, 2013d). The CAA gives EPA the authority to limit emissions of air pollutants coming from sources like chemical plants, utilities, and other industries, in partnership with state and tribal governments.

In 2003 EPA denied the petition by civil society organizations and states to include and regulate four GHGs under the CAA section 302(g). In their decision, EPA concluded it did not have the authority to regulate GHGs for purposes of climate change nor to set GHG emissions standards for new vehicles. The federal appeals court in Washington DC, upheld EPA's denial of the petition (U.S. EPA, 2010a).

However, in 2007 the Supreme Court's ruling in *Massachusetts V. EPA* brought the four major GHG emissions - carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons – into the CAA's air pollution criteria. In this case, the Supreme Court reversed the lower court's decision and held that EPA had improperly denied the petition. The Court held that GHGs are air pollutants under the CAA and that the alternative grounds EPA gave for denying the petition were "divorced from the statutory text" and hence improper. Specifically, the Court decided that carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons fit the CAA's "sweeping definition of 'air pollutant' " since they are "without a doubt 'physical [and] chemical substances which [are] emitted into the ambient air.' The statute is unambiguous" (U.S. EPA, 2010a).

The decision solidified EPA's authority to regulate GHG emissions. In 2009, EPA issued its "endangerment findings" to include GHGs as harmful to public health and welfare.

President's Climate Action Plan

In June 2013, the Obama Administration released a *Climate Action Plan* to address climate mitigation and adaptation strategies at the federal level. The most significant policy element is the target to reduce economy-wide GHG emissions to 17% below 2005 levels by 2020 and to place regulatory limits on stationary sources of GHG emissions (e.g. power plants).

Achieving the reduction target would reduce U.S. total GHG emissions to 4,979 million metric tons (MMT) per year in 2020. The *Annual Energy Outlook 2013* currently predicts that U.S. total carbon emissions will increase to 5,455 MMT in 2020 (EIA, 2013). Achieving President Obama's policy target by 2020 means reducing current U.S. total GHG emissions by 476 MMT in 2020.

In 2012, EPA finalized draft rules for both new and existing power plants, and offered up draft rules for public discussion, receiving over two million public comments. The agency's new rules separate standards for coal and natural gas power generation based on feedback from citizens and industry as currently outlined by EPA:

- All new power plants will be required to limit the amount of carbon dioxide they emit once the rules go into effect;
- New large natural gas-fired power plants will have to limit CO_2 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).

The most efficient coal plants emit 1,800 pounds of CO_2 per MWh (Volcovici, 2013). Achieving the 1,100 lbs/MWh limit will likely require coal plants to capture and store up to 40% of the carbon pollution they produce. In contrast, the most advanced natural gas plants emit 800-850 pounds of CO_2 per MWh (Koronowski, 2013), meaning new natural gas plants can more easily meet the obligation of the standards. For existing power plants, EPA is currently working with states and diverse stakeholders to determine appropriate guidelines to reduce GHG emissions from stationary sources.

These draft rules constitute the *new source performance standards (NSPS)* that may affect new generation units within Hawai‘i. Because the NSPS rules are in the draft and comment stage, it is still uncertain whether they will be implemented at the plant level, among plants by fuel type, or, most broadly, through an entire system/region.

Hawai‘i's Climate Change Law and Policy

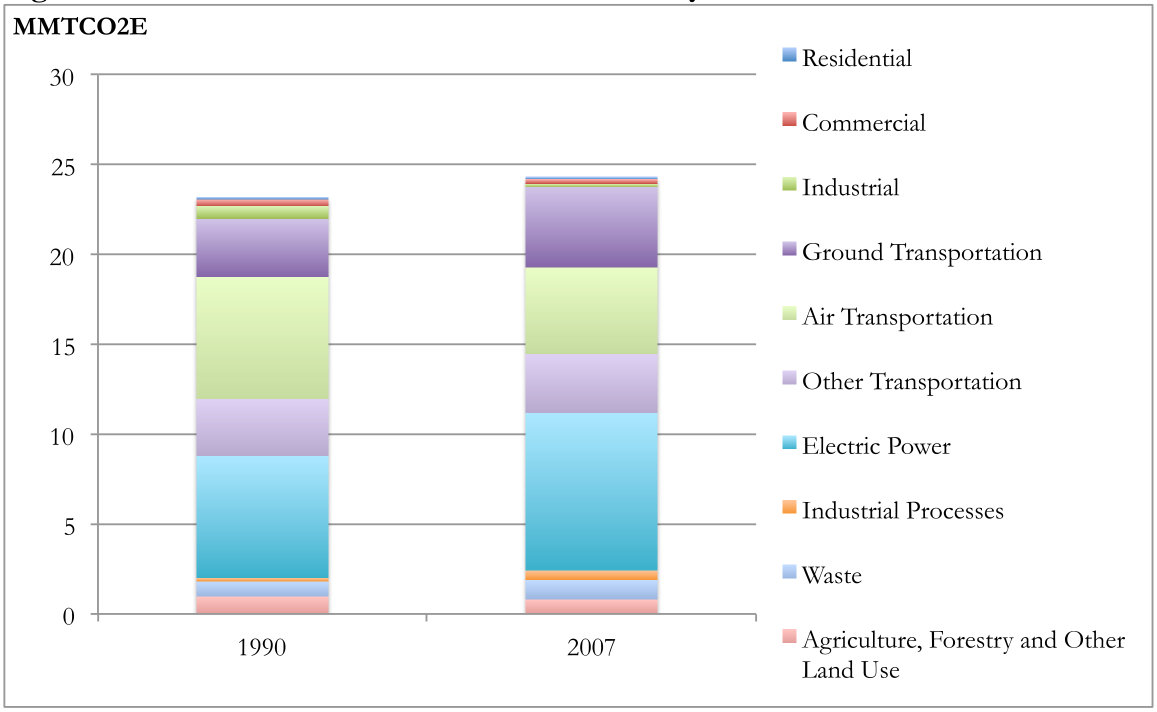
According to the 2012 *Climate Change Law and Policy Briefing Sheet* prepared by UH Seagrant, Hawai‘i is already experiencing the following impacts of climate change:

- Increases in air temperature, especially at high altitudes;
- Decreased stream base flow;
- Decreases in rainfall and rain intensity, with longer periods of days without rain;
- Rising sea levels;
- Ocean acidification; and
- Increased sea surface temperature, leading to more frequent and severe coral bleaching events.

In response to both climate change and high energy prices, the State of Hawai‘i has introduced regulation to reduce dependence on fossil fuels and move towards a "clean energy economy." Currently, Hawai‘i has a Renewable Portfolio Standard (RPS) that requires 40% of electricity sales be supplied with renewable sources by 2030, and an energy efficiency portfolio standard (EEPS) that mandates a 4,300 gigawatt hour (GWh) reduction in electricity use by 2030 (equal to about 40% of 2007 electricity generation). Furthermore, Hawai‘i's 2007 Climate Change Solutions Act (Act 234) mandates the reduction of GHG emissions to (or below) 1990 levels by January 1, 2020, excluding aviation fuels.

In response to the Act, a study was completed that provides comprehensive GHG inventories for Hawai‘i in the years 1990 and 2007 (ICF International, 2008). In 2007, Hawai‘i' released 22 MMT of CO_2e GHG emissions (17.3 MMT excluding aviation) into the earth's atmosphere. This is equivalent to the carbon sequestered by 1.7 billion tree seedlings grown for 10 years (U.S. EPA, 2013e). Figure 2 below shows the distribution of GHG emissions in Hawai‘i in 1990 and 2007.

Figure 2. 1990 and 2007 Hawai'i GHG Emissions by Sector



Source: ICF, 2008.

The electric sector, shown in blue, accounts for 30% and 36% of total GHG emissions in 1990 and 2007, respectively. In total, economy-wide GHG emissions increase by 3% from 1990 to 2007. There was, however, considerable reduction of aviation fuel use in this time due primarily to gains in efficiency. Thus excluding aviation-based emissions, as required by Act 234, implies a 22% increase.

Implementation of Act 234

Act 234 requires that statewide GHG emissions be reduced to 1990 levels (excluding aviation-related emissions) or lower by January 1, 2020. This amounts to reducing statewide GHG emissions, excluding aviation, to an estimated 13.66 MMT CO2e (DOH, 2012). Act 234 provides the State of Hawai'i Department of Health (DOH) with the authority to control air pollutants, establish a permit program to enforce reductions, and charge fees to support the air program. It sets the framework for the DOH to:

A. Adopt the statewide GHG emissions limit of 1990 levels, or lower, by 2020;
B. Establish the principle of seeking reductions that are technically feasible and cost-effective; and
C. Require reporting and verification of statewide GHG emissions to ensure compliance (DOH, 2012).

Although the proposed rules apply to all regulated sources of GHG emissions, the initial requirements apply to only stationary sources (approximately 25 facilities). These twenty-five stationary sources meet the threshold of existing facilities with potential emissions equal to or above 100,000 short tons of CO_2e per year and represent approximately 90% of Hawaiʻi's GHG emissions from stationary facilities (DOH, 2012). Table 1 reports the level of estimated carbon pollution emitted from these 25 stationary sources in 2010.

Table 1. Estimated Emissions of 25 Regulated Facilities Regulated under Act 234

Facility Name	Total metric tons CO_2e
HECO-Kahe	4,206,894
HECO-Waiau	3,714,566
AES	3,688,214
MECO-Maalaea	1,324,203
Kalaeloa	1,206,494
HC&S	1,044,042
HECO-CIP	965,494
HECO-Hon	805,600
KIUC-Port Allen	720,728
Tesoro	664,178
Chevron	664,178
Covanta HPOWER*	600,750
HECO-Kanoelehua Hill	479,071
HELCO-Keahole	448,870
MECO-Kahului	357,091
HELCO-Puna	343,265
Hamakua	322,166
C&C Hon - Waimanalo Gulch Landfill	218,557
Tradewinds Forest Products, LLC	200,232
Gay & Robinson	190,505
KIUC - Kapaia	157,289
HELCO-Shipman	154,057
Central Maui Municipal Landfill	121,753
C&C Hon - Kapaa/Kalaheo Landfill	108,508
West Hawaiʻi Landfill (WM)	97,457

Source: DOH, 2013.

Honolulu's Municipal Waste Combustion (MWC) is exempt from the requirements of revised rule (Section 11-60.1-204(c), HAR). Additionally, four Municipal Solid Waste (MSW) facilities are conditionally exempt, if the MSW landfills maintain gas collection and control systems to minimize GHG emissions (primarily methane). The DOH determined that exempting MWC and MSW operations had a minor effect on the percentage of GHG reductions needed to achieve the 2020 goals (DOH, 2012). Furthermore, the MWC operations lower GHG emissions from landfills by diverting or reducing waste going into landfill.

In summary, DOH's proposed GHG rule identifies 20 affected stationary sources and requires:

A. *A 16% reduction from 2010 levels (as a new baseline year) for non-biogenic* emissions and any *biogenic nitrous oxide and methane emissions by 2020.*
B. Submission of a six part GHG Emission Reduction Plan:
   a. Facility-wide baseline annual emission rate;
   b. The 2020 facility-wide GHG emissions cap;
   c. Available control measures;
   d. Technically feasible measures;
   e. Control effectiveness and cost evaluation; and
   f. Proposed control strategy.
C. That the facility justifies an alternate cap if the 16% calculated cap cannot be achieved. This then requires approval from the DOH director.
D. *Flexibility in meeting cap for affected facilities. This means that affected facilities may partner among each other to reach GHG reduction goals.*
E. *Exclusion of Biogenic CO_2 emissions in determining compliance with the cap.*

Our analysis focuses on the three requirements in italics above. The first (A) both 1) establishes the GHG cap and 2) states that biogenic sources of not subject to restrictions (along with E). The second (D) allows for "partnering" between identified facilities.

The 16% reduction from 2010 emissions cap is a key component of the DOH proposed rules and determines the impact on electricity operations in our analysis. The rules do not address standards for new generation units.

Partnering of Affected Facilities

The DOH proposed rules allow for partnering between affected facilities. This means that identified facilities may jointly meet their GHG emissions reduction target. Economically speaking, this makes the proposed rules akin to a system of tradable permits. Within one company, this is like having a company-wide cap where facilities are likely to be pooled together in their entirety. Between companies, if a facility has a higher GHG abatement cost than another, it may "partner" with a facility with a lower GHG abatement cost – likely meaning that it will pay a negotiated price between the two facility's marginal abatement costs such that both units are made financially better-off through the partnership.

In addition, there is little economic difference between implementing a system of tradable permits between affected facilities and between the entire electricity system (not accounting for transaction costs). If a facility has relatively high GHG abatement costs, it can reduce generation and that amount of generation can be filled with sources from non-affected facilities.

Biofuel GHG Emissions Accounting

The DOH proposed rules exclude biogenic sources of emissions. Biofuels tend to burn like fossil fuels. Therefore, if only out-of-stack emissions are considered, biofuels would be assigned a similar GHG emissions factor as oil-based fuels. However, a thorough evaluation of the GHG effects of switching from fossil fuels to biofuels requires life cycle analysis

(LCA), or well-to-stack analysis. LCA captures GHG emissions from all stages in the energy process as opposed to only smokestack or tailpipe emissions. Much of the LCA literature focuses on biodiesel and ethanol, given their potential to displace conventional oil in either power generation or transportation or both. However, quantifying the environmental benefits of biofuel is difficult. While most studies find that displacing petroleum-based fuels with biofuels reduces GHG emissions, estimated reductions vary widely, even for similar bioenergy systems (Cherubini et al., 2009). Biofuel-based GHG emissions are highly dependent on the type of feedstock and the production and feedstock to fuel conversion technology. In addition, aside from different data, methodologies, allocation methods, reference systems, and assumptions, other local influences such as land-use change and soil emissions yield a variety of results (see for example, Cherubini and Stromman, 2011 and Malca and Freire, 2011). Finally, the fuels (and pathways) considered in many published LCA studies are not necessarily commercially viable.

Several national studies have examined biodiesel derived from soybean oil. The National Renewable Energy Laboratory (NREL) found that use of biodiesel to replace petroleum diesel would reduce CO_2 emissions by 78% (Sheehan et al., 1998). A later study by Argonne National Laboratory found GHG emissions could be reduced by more than 66% (Huo et al., 2008). Pradhan et al. (2012) showed lifecycle GHG emissions from soybean biodiesel were 81% lower than those of petroleum diesel (based on 2005 data); excluding lime and soil N_2O emissions implied an 85% reduction, which is directly comparable to the lifecycle emissions in the 1998 NREL study. In Hawai'i, a 2012 UHERO study analyzed three different land-based feedstocks—jatropha, soybean, and oil palm—and found jatropha yields the highest, 80%, GHG emissions reduction (Tokunaga et al., 2012). However, with the exception of Pradhan et al. (2012), none of the studies cited here account for land-use change. Pradhan et al. (2012) results suggest that GHG emissions reduction falls to 76% when including indirect land use changes, and 55%, under the same assumption as the EPA Renewable Fuel Standard Program report that states biofuels alone are responsible for the total GHG impact of land use change (U.S. EPA, 2010b). This estimated 55% reduction is comparable to the reported 57% by the EPA (U.S. EPA, 2010b).

III. Hawai'i Electricity Model

To consider the impact of Federal and State GHG regulations on Hawaii's electric sector, we use a detailed model of the electric sector called the Hawai'i Electric Model (HELM).

Description of HELM

HELM is a fully dynamic, partial equilibrium model of Hawai'i's electric sector. Often referred to as "bottom-up" models, this type of model supports detailed analysis based on capital and operating costs, technological constraints, and environmental factors (Zhang and Folmer, 1998). 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.

HELM is calibrated to existing electric generating units for Hawai'i's four counties in 2013 (and scaled to $2007). It solves in 5-year intervals from 2010 until 2040.[1] Future energy price forecasts are based on the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO) *2013*. The baseline electricity demand projections for Hawai'i, Maui, and Oahu projections are adopted from HECO's Integrated Resource Plan (IRP)-4 Stuck In The Middle case. Kauai's electricity demand forecast is taken from its IRP-3.

HELM is formulated as a quadratic program using GAMS (General Algebraic Modeling System) and is solved using the MOSEK solver. For more information on this modeling platform, refer to Rosenthal (2008). For a complete technical description of HELM, see Appendix I and Coffman, Griffin and Bernstein (2012).

Unit Data

The database for HELM 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

[1] HELM includes all new generation constructed from 2008 to 2013 in each model run.

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.

In addition "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 (HEI, 2013; U.S. DOE, 2013a). Capacity factors for new wind units are also from the 2013 IRP. In addition, based on Hawai'i 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 – reducing its capacity to zero – if it ceases to be cost-effective. Oil-burning units can be modified to burn bio-oil or biodiesel 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 2 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), 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 both conventional and bio-based oil.

Table 2. Cost and physical characteristics of existing and new units (2007$)

	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	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

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.

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

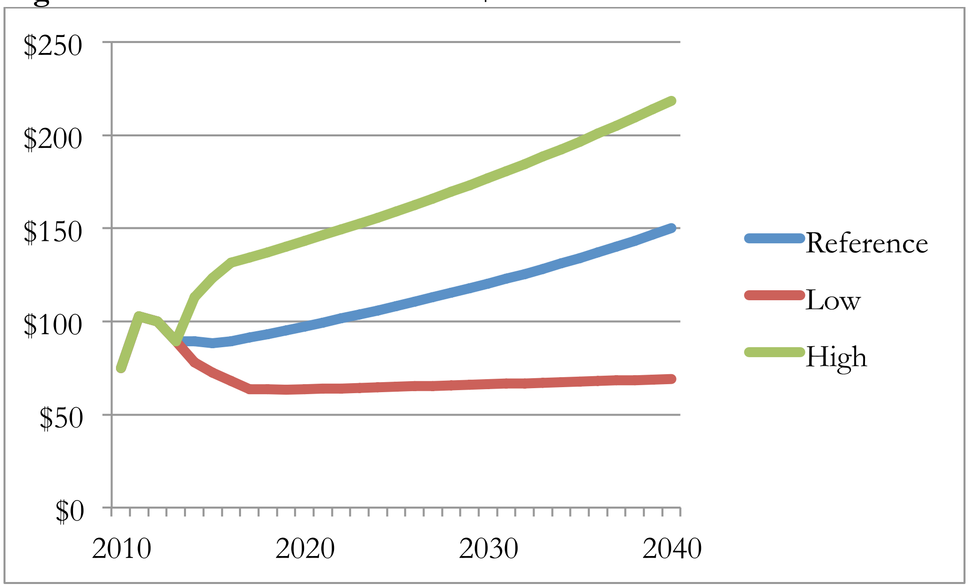
[b] We assume that all new MSW is built and there is a minimum generation requirement imposed for both existing and new MSW capacity.

We assume that all technologies are able to come on-line based on current policies and technological constraints. There operations can be dictated by must-run units or minimum generation requirements. Capacities for new units are based on proposed projects (EIA, 2012a; DBEDT, 2013) as well as the maximum possible capacity additions specified by county in the Hawai‘i Solar Integration Study and report submitted to the Hawai‘i PUC by the Renewable Standards Working Group (GE Consulting, 2012; RSWG, 2013). In addition, we assume in the baseline that further use of coal is limited in Hawai‘i because, in 2008, the Hawaiian Electric Company signed an agreement in which it voluntarily committed to not use more coal for electricity generation (DBEDT, 2008). Coal seldom enters the energy planning dialogue in Hawai‘i; for instance, there is no mention of coal in HECO's 2013 IRP.

Fuel Prices

Future fuel prices are calibrated to EIA's *Annual Energy Outlook 2013*'s low, reference and high scenarios for oil, coal and ethanol. The trend of future ethanol prices is used as a proxy for biofuel prices, and the initial biofuel price is based on current prices. Because of the close substitutability between biofuels and oil, we assume that biofuels are priced at or above their fossil-counterparts. The oil price trajectory is shown in Figure 3 below.

Figure 3. Oil Price Forecast in 2013$



Source: AEO 2013, Brent Spot Price.

In the *reference* fuel price case, prices approximately double in real terms from 2010 to 2040. In the *low* case, they remain steady. In the *high* case, they approximately triple.

Scenarios and Major Assumptions

Given uncertainty regarding the final implementation of the DOH and EPA draft rules, we rely on a number of assumptions and develop a series of scenarios to highlight the effect of GHG policies on Hawai'i's electric sector.

Major Assumptions:

A. All existing electricity generation units (identified as "affected" by DOH) are governed by the DOH proposed rules[2] – mandating a 16% reduction from 2010 levels of GHG emissions by 2020.
B. All new electricity generation units must meet the EPA's draft New Source Performance Standard.[3]

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[2] We develop up a bottom-up GHG inventory within HELM and thus we approximate the DOH proposed rules using the same percentage reduction from 2010 GHG levels. This means that the GHG emissions reductions are internally consistent within HELM, but are not identical in level values to that adopted by DOH. For economic impact analysis, it is the relative change that is important.

C. New generation units can be built to the capacity allowed by HELM (as described in Table 2 above). This means that there is no new coal production within the baseline assumption (though this assumption is relaxed in the sensitivity analysis).
D. No interisland electricity cables are laid to connect the island grids.
E. The "baseline" scenario does not include any State or Federal level GHG restrictions. This means that only the State's RPS is enforced. This baseline scenario provides a benchmark against which to assess the effects of the GHG policies.

Scenarios:

A. We consider three oil price cases, based on the U.S. EIA's *Annual Energy Outlook 2013* reference, low, and high fuel price.
B. We consider two "extreme" outcomes of DOH's *facility partnering* concept, where either 1) existing facilities (i.e. in this case, plants) do not partner at all (meaning that plants alone reduce their GHG emissions) or 2) existing facilities through the entire electricity system partner to meet the statewide target. The reality will likely be somewhere in-between.
C. We consider two "extreme" interpretations of EPA's NSPS. We assume either the NSPS is implemented 1) at the unit level, or 2) at the system level. In our best interpretation of public information to-date, it seems the final ruling will likely be between fossil-fired units.
D. We consider a case where the DOH proposed GHG rules govern both existing and new electricity units – essentially acting as a sector-wide GHG cap. This means that GHG emissions must remain 16% below 2010 levels from 2020 through the model time horizon.
E. We consider a change to the DOH's rule excluding biogenic sources of GHG emissions. Instead, we include them based on a *lifecycle approach* and, for illustration purposes, assume that biofuels provide a 50% improvement in GHG emissions over conventional oil (U.S. DOE, 2013b).
F. We consider the case where new coal units are able to be built – to better understand whether the GHG regulations will prohibit new coal units more firmly than the current voluntary mechanisms.

Using different permutations of the above scenarios and assumptions result in 15 different scenarios that are analyzed within HELM. Table 3 lists all the scenarios considered.

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[3] The EPA proposed different standards for boilers and new gas units of 1,100 lbs CO_2/MWH and 1,000 lbs CO_2/MWh, respectively. The proposed standard for smaller units is 1,100 lbs CO_2/MWH. Given the uncertainty and small size of new units in Hawaiʻi, this study assumes a standard of 1,100 lbs CO_2/MWh (see http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0001).

Table 3. List of scenarios run through HELM

Scenario Name	Oil Price Forecast	Biogenic Emissions Included?	DOH Policy Structure	Federal Policy Structure	New Coal Allowed?
Baseline	Reference, High, Low	N/A	N/A	N/A	No
Scenario 1	Reference, High, Low	No	Facility-Level	Facility-Level	No
Scenario 2	Reference, High, Low	No	System-Wide	System-Wide	No
Scenario 3	Reference, High, Low	No	GHG Cap, System-Wide	N/A	No
Sensitivity Biofuel A	Reference	Yes	Facility-Level	Facility-Level	No
Sensitivity Biofuel B	Reference	Yes	System-wide	System-Wide	No
Sensitivity Coal	Reference	Yes	System-wide	System-Wide	Yes

IV. Results

For ease of presentation, we showcase results from the *reference* oil price case, where biofuels are excluded from the DOH GHG rule (as is currently proposed) and no new coal production is allowed (as representative of the Hawai'i Clean Energy Initiative voluntary agreement). Within the sensitivity analysis, we relax these assumptions.

Baseline

Table 4 shows the mix of electricity generation in the baseline scenario, where there is no GHG regulation. The key assumptions in the baseline scenario include: 1) fuel prices follow the *reference* AEO 2013 oil price trajectory, 2) the RPS is met, 3) no new coal is allowed, 4) and new units have an operating profile and maximum capacity as described in Table 2.

Table 4. Share of Electricity Generation by Fuel/Technology (%)
Baseline

	2010	2015	2020	2025	2030	2035	2040
Total Generation (TWh)	*11.0*	*11.3*	*12.1*	*12.7*	*13.4*	*14.2*	*15.1*
Oil	70%	55%	55%	54%	52%	53%	54%
Wind	6%	14%	15%	16%	15%	15%	14%
Rooftop PV	4%	4%	5%	6%	8%	10%	10%
Coal	13%	13%	12%	11%	11%	10%	10%
Geo	3%	5%	5%	5%	5%	5%	5%
Utility Solar	0%	3%	3%	3%	3%	3%	3%
MSW	3%	3%	3%	2%	2%	2%	2%
Hydro	1%	2%	2%	2%	2%	1%	1%
Bio	1%	0%	0%	0%	2%	1%	1%

In the baseline, *reference* fuel prices coupled with the RPS induce a large switch toward renewable sources of energy, primarily wind and rooftop PV. In 2040, wind generation is estimated to account for 14% of generation and rooftop PV, 10%.[4] Because wind energy is quite cost effective, most of the capacity is built in early years (2015-2020). Due to assumptions about the rate at which PV can be added to the grid (passing current grid restrictions), PV enters the system more slowly (see Appendix I). These sources offset the need for additional oil-fired generation, and oil-use declines from 70% in 2010 to 54% in 2040. A small amount of biofuel is used to re-power existing oil-fired units, accounting for 1% of energy generation in the year 2040. Geothermal energy is constrained to meet the baseload needs of Hawai'i Island and thus, while a relatively inexpensive and firm source of energy, it remains a relatively small portion of the State's overall energy needs (5%). Because no new coal is built, by assumption, the relative proportion of coal use declines (from 13% in 2010 to 10% in 2040) as electricity demand grows.

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[4] In later years, all systems are constrained by HELM's assumption about the levels of intermittent generation on the system at any given time. More intermittent sources of energy such as wind and solar could be incorporated if we made additional assumptions about system upgrades and subsequent costs. That is outside the scope of this analysis.

Table 5 shows the cost of providing electricity and GHG emissions on an annual basis and over the entire 30-year time horizon. GHG emissions are presented in three ways. The first uses the accounting system currently proposed by DOH: including out-of-stack emissions for all fuels/technologies with the exception of biogenic sources, which are considered to have zero emissions. The second uses a more global view of GHG emissions, where all fuels/technologies are accounted for based on their lifecycle emissions. Lifecycle emissions are based on the GREET Model (Argonne National Laboratory, 2010).[5] The third is a hybrid approach and includes out-of-stack emissions for all other fuels/technologies and lifecycle emissions for biofuels.

Table 5. Costs ($B) & CO_2 Emissions ($MMTCO_2$)
Baseline

	2010	2015	2020	2025	2030	2035	2040	30-Year Total[6]
			$ Billion					
Capital Cost	0.0	5.2	5.8	1.6	2.0	2.0	1.2	18
Fuel Cost	9.2	8.6	8.4	9.6	10.9	12.6	15.1	67
O&M	1.9	1.9	1.7	1.8	1.9	1.9	2.0	12
Grand Total	11.1	15.7	15.9	13.0	14.7	16.6	18.4	97
			Electric Sector CO_2 Emissions $MMTCO_2$					
DOH CO_2 Accounting	7.4	6.1	5.6	5.7	5.7	6.0	6.4	185
Lifecycle Accounting	9.5	7.9	7.2	7.4	7.5	7.8	8.3	239
DOH CO_2 Acct + Lifecycle Biofuels	7.4	6.1	5.6	5.8	5.8	6.1	6.4	186

Over the 30-year time horizon, a total of $18 billion are spent on capital costs, $67 billion on fuel, and $12 billion on operations and maintenance.[7] In sum, $97 billion is spent operating the electricity sector over 30 years.

In terms of GHG emissions, the market forces of increasing fuel prices lead to a reduction in GHG emissions in the baseline scenario, from 7.4 $MMTCO_2$ in 2010, to a low of 5.6 $MMTCO_2$ in 2020 and back up to 6.4 $MMTCO_2$ in 2040. This is assuming both *reference* fuel prices and that there is not large-scale fuel switching to a lower-cost fossil fuel (such as coal or LNG).

In addition, the difference in accounting for GHG emissions does matter, particularly in the distinction between out-of-stack and lifecycle emissions. Because biofuels are largely uneconomical and do not come into the system en masse, there is only a small difference when lifecycle biofuel emissions are added to DOH's current framework.

[5] See Appendix I for further detail.
[6] This is from the year 2011-2040, assuming that each year's figure is representative of 5 years (with the exception of 2010 and 2014 [Do you mean 2040?]).
[7] Capital costs are assumed to be paid up-front at the overnight cost of capital. Note that financing of capital would include an additional capital charge rate and spread out the capital costs over time.

The baseline figures are used for comparing the generation cost and GHG impacts of pending State and Federal GHG regulations.

Reference Fuel Prices

In the *reference* fuel price case, we consider three primary scenarios: 1) "Facility-level restrictions" of GHG emissions—that is the DOH does not allow partnering and the EPA's NSPS is implemented at the facility (unit) level, 2) "System-wide restrictions" of GHG emissions—that is, the DOH allows system wide partnering and the DOH GHG cap and the EPA's NSPS are implemented at the system level, and 3) that the DOH GHG cap acts as an electric sector-wide cap through the model time horizon. These scenarios cover the range of implementation options for the DOH and NSPS regulations. In these scenarios, biofuel-based emissions are excluded, and new coal units are prohibited from being built.

Scenario 1: Facility-Level Restrictions

Table 6 shows electricity generation by type under the case that there is no partnering and the NSPS is implemented at the unit level.

Table 6. Electricity Generation by Fuel/Technology
Scenario 1: Facility-Level Restrictions

	2010	2015	2020	2025	2030	2035	2040	Diff from Baseline in 2040
Total Generation (TWh)	*11.0*	*11.3*	*12.0*	*12.7*	*13.4*	*14.2*	*15.1*	*0.0*
Oil	70%	55%	50%	50%	49%	48%	49%	-5%
Wind	6%	14%	16%	16%	15%	15%	14%	0%
Rooftop PV	4%	4%	5%	6%	8%	10%	10%	0%
Bio	1%	0%	7%	7%	8%	8%	8%	7%
Coal	13%	13%	10%	9%	9%	8%	8%	-2%
Geo	3%	5%	5%	5%	5%	5%	5%	0%
Utility Solar	0%	4%	3%	3%	3%	3%	3%	0%
MSW	3%	3%	3%	2%	2%	2%	2%	0%
Hydro	1%	2%	2%	2%	2%	1%	1%	0%

The major distinction between this scenario and the baseline is the switch away from oil and towards biofuel use. This is because oil-fired units are re-powered in part by biofuel to meet the facility cap. Because this scenario assumes DOH's policy is implemented at the facility level, the AES coal unit must reduce its generation to comply with its emissions cap. Coal-fired generation decreases by 16% from the baseline.

When DOH's policy is implemented at the facility-level, the RPS law is "overshot." In this case, 47% of electricity sales are met through renewable sources by the year 2040.

Table 7 shows the GHG emissions outcomes and system costs as a result of facility-level implementation.

Table 7. Costs ($B) & GHG Emissions ($MMTCO_2$)
Scenario 1: Facility-Level Restrictions

	2010	2015	2020	2025	2030	2035	2040	30-Year Total	30-year Total Diff from Baseline	*Cost of GHG Abatement $/ton CO_2 reduced*
				$ Billion						
Capital Cost	0.0	5.5	5.5	1.7	2.0	2.0	1.1	18	0	
Fuel Cost	9.2	8.6	9.0	10.1	11.3	13.0	15.7	70	3	
O&M	1.9	1.9	1.8	1.8	1.9	2.0	2.1	12	0	
Change in CS from Baseline	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0	0	
Grand Total	11.1	15.9	16.5	13.7	15.1	17.0	18.9	99.4	3.0	
				Electric Sector CO_2 Emissions $MMTCO_2$						
DOH CO_2 Accounting	7.4	6.1	4.9	5.1	5.1	5.3	5.7	168	-17	$176
Lifecycle Accounting	9.5	7.8	6.7	6.9	7.0	7.3	7.8	227	-13	$235
DOH CO_2 Acct + Lifecycle Bio	7.4	6.1	5.2	5.4	5.5	5.7	6.1	178	-9	$344

GHG emissions are estimated to be reduced by 17 $MMTCO_2$ relative to the baseline, under DOH's currently proposed accounting framework. Because of the introduction of biofuels, this emissions reduction benefit diminishes if assessed from a global environmental perspective, with a 13 $MMTCO_2$ reduction in the case of lifecycle accounting and 9 $MMTCO_2$ reduction in the case of lifecycle accounting just for biofuels.

Depending on the accounting framework, abatement costs range from $176/ton CO_2 reduced to $344/ton.[8] In contrast, in California's GHG emissions trading market, permits trade between $10-$15/ton CO_2 (EIA, 2012; The Energy Collective, 2013). Thus this form of strict facility-level regulation leads to high compliance costs. The cost of the facility level programs does not account for transaction costs, including the cost of setting up a new monitoring system at DOH and company-level costs.

Scenario 2: System-Wide Restrictions

At the opposite extreme, Table 8 shows electricity generation when there is system-wide partnering to comply with DOH regulation and the NSPS is implemented at the system level. By implementing NSPS at the system level, we assume that the system emissions rate is defined as the ratio of emissions from new sources of generation (i.e., post 2014) to generation from all new sources. Therefore new sources include both fossil and non-fossil sources of generation. This assumption is one of the least restrictive interpretations of how NSPS regulations could be defined.

[8] This cost corresponds to a biogenic emissions equal to half that of the lifecycle emission of oil. If lifecycle biogenic emissions are less, then the cost would be lower.

Table 8. Electricity Generation by Fuel/Technology
Scenario 2: System-Wide Restrictions

	2010	2015	2020	2025	2030	2035	2040	Diff from Baseline in 2040
Total Generation (TWh)	*11.0*	*11.3*	*12.1*	*12.7*	*13.4*	*14.2*	*15.1*	*0.0*
Oil	70%	55%	55%	54%	52%	53%	54%	0%
Wind	6%	14%	15%	16%	15%	15%	14%	0%
Rooftop PV	4%	4%	5%	6%	8%	10%	10%	0%
Coal	13%	13%	12%	11%	11%	10%	10%	0%
Geo	3%	5%	5%	5%	5%	5%	5%	0%
Utility Solar	0%	3%	3%	3%	3%	3%	3%	0%
MSW	3%	3%	3%	2%	2%	2%	2%	0%
Hydro	1%	2%	2%	2%	2%	1%	1%	0%
Bio	1%	0%	0%	0%	2%	1%	1%	0%

It is important to note that there is virtually no difference in the generation profile between this scenario and the baseline case where no regulatory framework is imposed. This is because *reference* fuel prices alone encourage compliance with both DOH and EPA GHG reduction rules (as discussed in the baseline results above). Therefore, there is also negligible difference in terms of costs and GHG emissions. This is shown in Table 9 below.

Table 9. Costs ($B) & CO_2 Emissions ($MMTCO_2$)
Scenario 2: System-Wide Restrictions

	2010	2015	2020	2025	2030	2035	2040	30-Year Total	30-year Total Diff from Baseline	
				$ Billion						
Capital Cost	0.0	5.2	5.8	1.6	2.0	2.0	1.2	18	0	
Fuel Cost	9.2	8.6	8.4	9.6	10.9	12.6	15.1	67	0	
O&M	1.9	1.9	1.7	1.8	1.9	1.9	2.0	12	0	
Change in CS from Baseline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	
Grand Total	11.1	15.7	15.9	13.0	14.7	16.6	18.4	97	0	
				Electric Sector CO_2 Emissions $MMTCO_2$						*Cost of GHG Abatement $/ton CO_2 reduced*
DOH CO_2 Accounting	7.4	6.1	5.6	5.7	5.7	6.0	6.4	185	0	$0
Lifecycle Accounting	9.5	7.9	7.2	7.4	7.5	7.8	8.3	239	0	$0
DOH CO_2 Acct + Lifecycle Bio	7.4	6.1	5.6	5.8	5.8	6.1	6.4	186	0	$0

Under this set of assumptions, the RPS policy achieves the necessary emission reductions for Hawai'i's electric sector to comply with Act 234. The GHG policy does not incur economic costs because market forces essentially lead to the same outcome. In other words, neither the proposed DOH GHG rules nor NSPS restrict generation and new build decisions under a system-wide partnering and system-wide NSPS assuming reference fuel prices.

Moreover, the NSPS is not restrictive because this scenario assumes NSPS averages the emission rates over all new generation sources. If instead the NSPS is computed by a system emissions rate considering only fossil-fired units, then no new oil-fired generation could come on-line unless gas-fired units also came on-line because the emissions rate for oil-fired units exceeds 1,100 lbs CO2/MWh. Furthermore, if the emissions associated with the liquefaction and regasification of natural gas were considered, then the emissions rate from gas-fired generation may also be close to 1,100 thus virtually eliminating the ability for any new oil-fired generation from coming on-line.

Scenario 3: Extended State GHG Cap

This scenario assumes that the DOH would require that all new GHG emitting generation units would have to be built under existing GHG permits. This is not currently specified in the proposed rules but could be a possible extension of the cap. In this instance, the NSPS would no longer apply to Hawaii because the GHG cap would be more binding than the NSPS concentration limits. We assume that there would be system-wide flexibility in meeting the GHG target. Table 10 shows the mix of generation in this scenario and the difference from the baseline in 2040.

Table 10. Electricity Generation by Fuel/Technology
Scenario 3: Extended State GHG Cap

	2010	2015	2020	2025	2030	2035	2040	Diff from Baseline in 2040
Total Generation (TWh)	*11.0*	*11.3*	*12.1*	*12.7*	*13.3*	*14.2*	*15.0*	*-0.1*
Oil	70%	55%	55%	54%	52%	53%	52%	-1%
Wind	6%	14%	16%	16%	15%	15%	14%	0%
Rooftop PV	4%	4%	5%	6%	8%	10%	10%	0%
Coal	13%	13%	12%	11%	11%	10%	10%	0%
Geo	3%	5%	5%	5%	5%	5%	5%	0%
Utility Solar	0%	3%	3%	3%	3%	3%	3%	0%
Bio	1%	0%	0%	0%	2%	1%	2%	1%
MSW	3%	3%	3%	2%	2%	2%	2%	0%
Hydro	1%	2%	2%	2%	2%	1%	1%	0%

There is little difference between this scenario and the baseline. There is a 1% reduction in the use of oil in the year 2040, and a switch towards biofuel instead. This acts as a means of meeting the GHG cap in later years, when the capacity limits for wind, in particular, are met. With different assumptions about the possible total penetration of wind energy and the rate at which PV can come onto the system, perhaps as a result of grid upgrades, the tradeoff is more likely to be between oil and these sources of renewable energy.

Table 11 shows the cost and GHG implications of the extended State GHG cap.

Table 11. Costs ($B) & CO_2 Emissions ($MMTCO_2$)
Scenario 3: Extended State GHG Cap

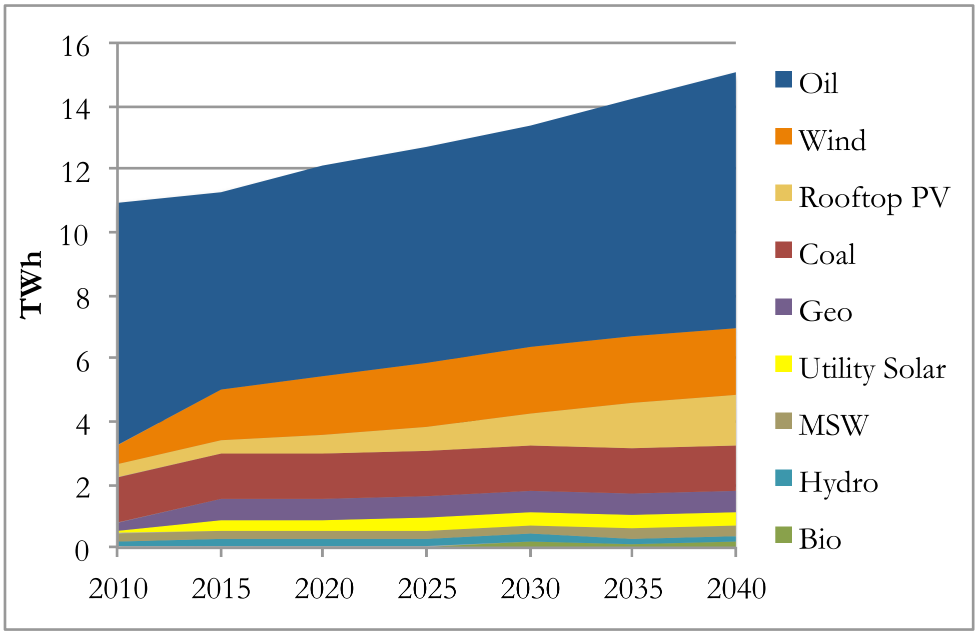
	2010	2015	2020	2025	2030	2035	2040	30-Year Total	30-year Total Diff from Baseline	*Cost of GHG Abatement \$/ton CO_2 reduced*
				$ Billion						
Capital Cost	0.0	5.2	5.8	1.6	1.9	2.2	1.1	18	0	
Fuel Cost	9.2	8.6	8.4	9.6	10.9	12.5	15.0	67	0	
O&M	1.9	1.9	1.7	1.8	1.9	2.0	2.1	12	0	
Change in CS from Baseline	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0	0	
Grand Total	11.1	15.7	15.9	13.0	14.7	16.7	18.3	97	0	
				Electric Sector CO_2 Emissions $MMTCO_2$						
DOH CO_2 Accounting	7.4	6.1	5.6	5.7	5.7	6.0	6.2	184	-1	$5
Lifecycle Accounting	9.5	7.9	7.2	7.4	7.5	7.7	8.1	238	-1	$5
DOH CO_2 Acct + Lifecycle Bio	7.4	6.1	5.6	5.8	5.8	6.0	6.3	186	-1	$7

Superseding the NSPS with a State GHG cap that extends over the model time horizon results in findings similar to that of Scenario 2 because of the similarity in system-wide flexibility in meeting the GHG targets. The GHG abatement costs are estimated to be between $5-7/ton CO_2. But Scenario 3 induces more emission reductions than Scenario 2.

Summary of Electricity Generation, 2010-2040

Figures 4 and 5 show electricity generation from 2010 to 2040 under the baseline and three scenarios. Figure 4 shows baseline electricity generation by technology, as well as overall demand.

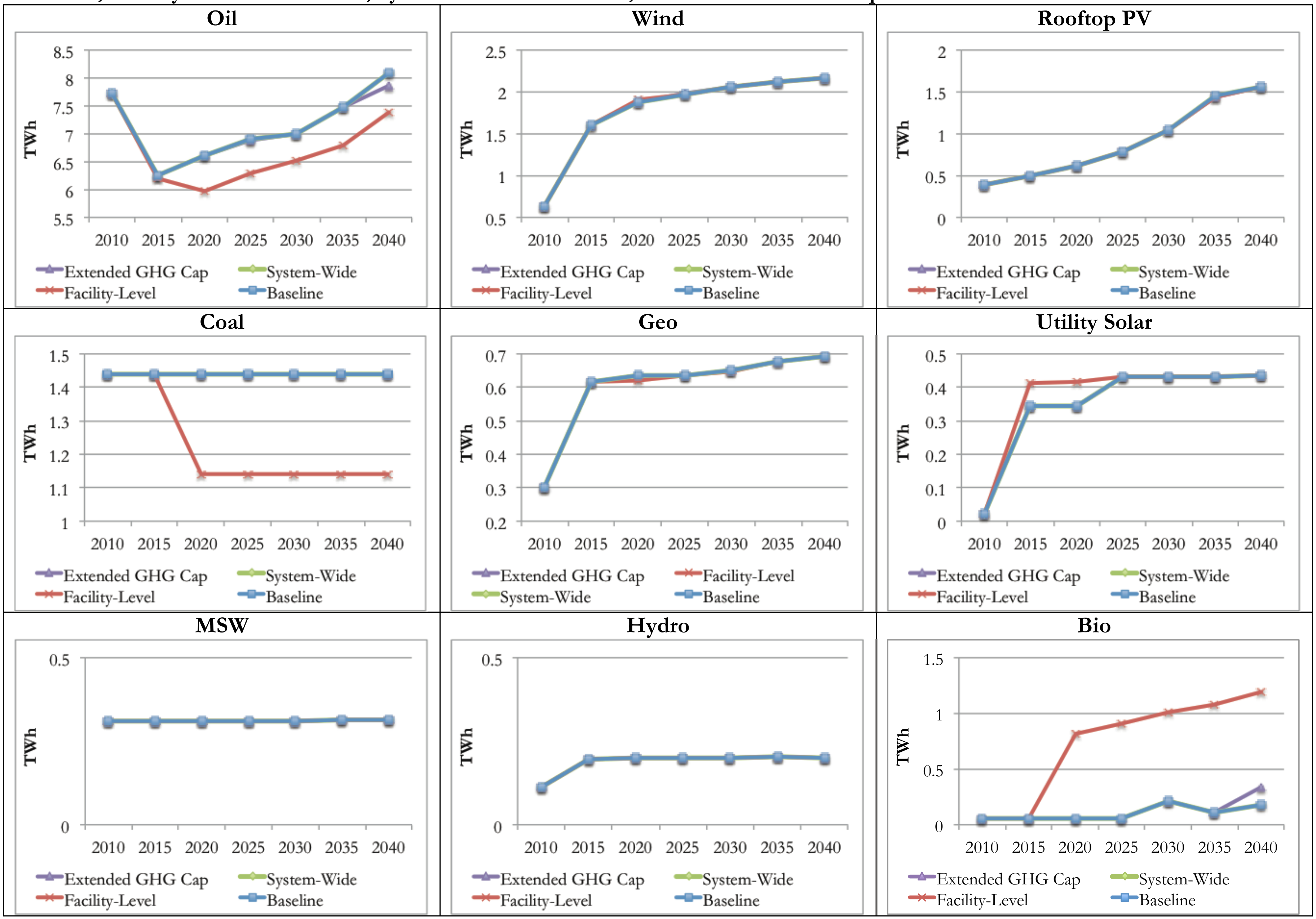
Figure 4. Electricity Generation by Fuel/Technology (TWh)
Baseline



This figure shows how electricity demand is met over time, where the portion of oil-fired generation relatively declines with, primarily, increased wind and rooftop PV. Coal-fired generation remains constant, by assumption and thus declines as a relative portion of overall electricity generation. The RPS is met, where 40% of electricity sales are met through renewable energy sources. The remaining 60% are met primarily through oil (assuming there is no introduction of LNG) and, to a much lesser extent, coal.

Figure 5 shows how electricity generation changes under the three scenarios in comparison to the baseline, under *reference* fuel prices. Note that the scale of the vertical axis is different for each fuel/technology.

Figure 5. Electricity Generation by Fuel/Technology (TWh)
Baseline, Facility-Level Restrictions, System-Wide Restrictions, and Extended GHG Cap



As this figure shows, there is the greatest reduction in oil use in facility-level GHG regulation. This oil-fired generation tends to be replaced by fuel-switching within existing generation units to biofuels. In the case of system-wide regulation, either with the NSPS or extended State GHG cap, much less biofuel-fired generation comes on-line because of its high cost. The exception is in the extended State GHG cap, where oil-fired generation declines in the year 2040 relative to the baseline and is replaced by bio-based generation. This occurs to continue compliance with the GHG cap, where other GHG neutral technologies have reached their capacity constraints. This is by assumption within the model. With additional data about the ability to increase the capacity of renewable energy technologies such as wind and solar, for example through grid upgrades, then there would likely be a switch from oil-based generation to other renewable sources. Because renewable energy sources such as wind and solar are cost-effective in the baseline, there is little difference between generation in the baseline and scenarios.

Sensitivity Analysis

Biofuel GHG Emissions

How to account for biogenic sources of emissions were an important and controversial topic for much of the public testimony submitted to the DOH. The current DOH proposed rules excludes biogenic sources of emissions from the GHG cap and may therefore lead to unfair preference for biofuels over other sources of renewable energy. Here we assess the impact of including lifecycle-based biofuel emissions within DOH's framework, namely a GHG accounting of the third type (DOH CO_2 Acct + Lifecycle Biofuels).

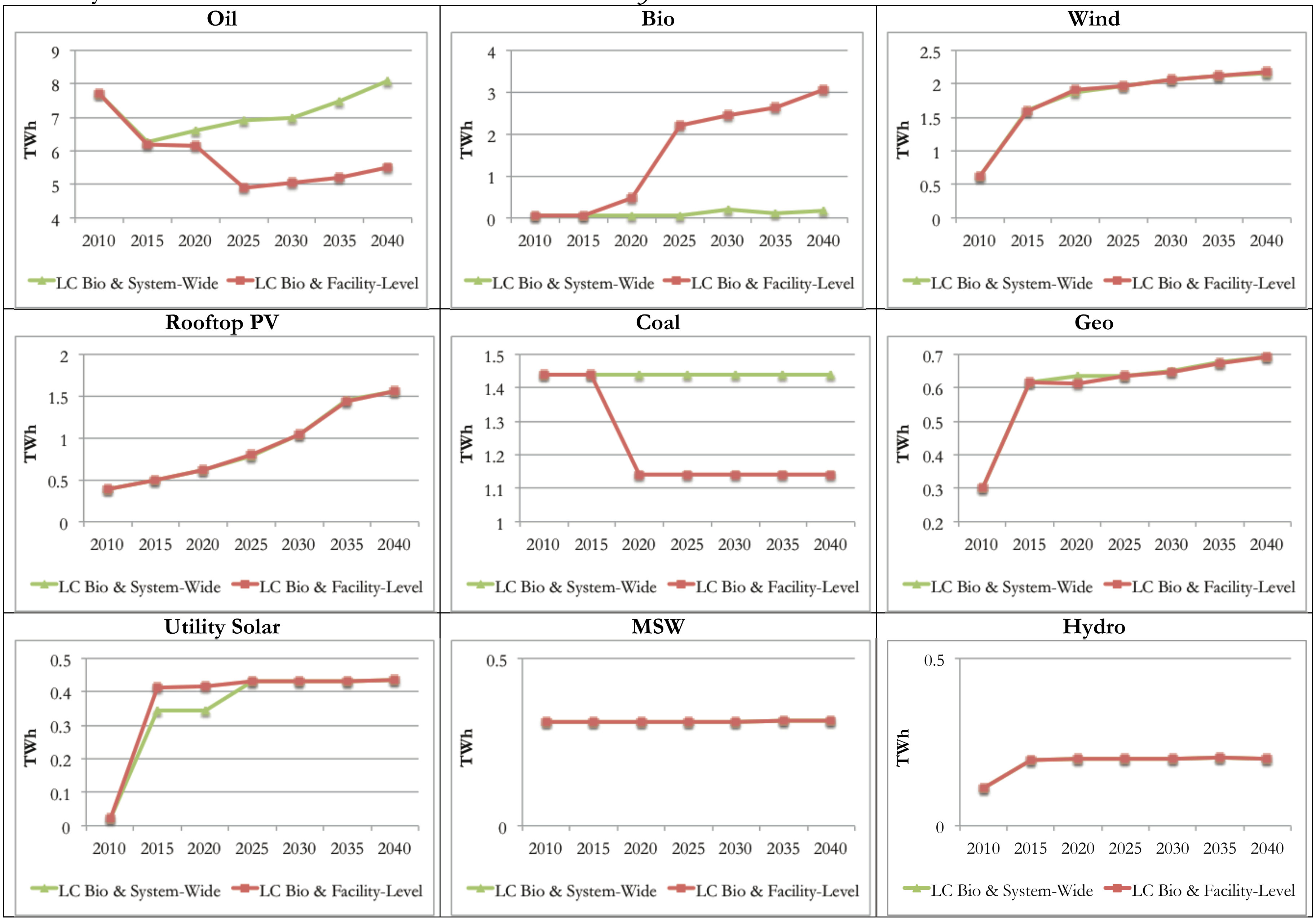
Our results are both interesting and counter intuitive. Rather than discouraging the use of biofuels, including biogenic sources of emissions in the GHG rules can encourage their use. This result is highly sensitive to the assumed fuel price forecasts and whether the GHG cap is implemented at the facility or system level.

In the case that there are facility-level restrictions and biogenic emissions are considered, 20% of electricity production is biofuel-based in the year 2040.[9] There is also significant over-shooting of the RPS—60% of electricity generation is met through renewable sources by the year 2040.

On the other hand, this finding is reversed when there is system-wide partnering. Biofuels are more costly than fossil fuels and other renewables. Therefore, when GHG rules allow for flexibility, even when biofuel-based GHG emissions are included in the rules, biofuel-fired generation is minimal. These two cases are shown in Figure 6 below.

[9] We find that the biofuel blending limit is binding. This means that even more biofuels might come onto the system if the blending limit is increased or there is 100% switching of units to biofuels.

Figure 6. Electricity Generation by Fuel/Technology (TWh)
Sensitivity Biofuel A: Lifecycle Biofuel-Based Emissions Included in DOH Rules *Facility*-Level Restrictions and Sensitivity Biofuel B: Lifecycle Biofuel-Based Emissions Included in DOH Rules *System*-Wide Restrictions



The reason for the substantial increase in biofuel-based generation in the case of facility-level restrictions is simple yet counterintuitive. If biogenic sources of emissions are accounted for in the DOH's rules and there is no partnering, then all current oil-fired generators must switch at least partially to biofuels or curtail their output to meet the facility GHG cap. The logic is shown in equation 1 below.

$$EC_{Oil} * Oil + EC_{Biofuel} Biofuel \leq GHGCap \quad (1)$$

Where:

EC_{Oil} and $EC_{Biofuel}$ are the emissions coefficients for oil and biofuel, respectively,

Oil and $Biofuel$ are the quantity of the oil and biofuel burned in the facility, respectively, and

$GHGCap$ is a constant, the total amount of GHG emissions allowed at that facility as set by the DOH proposed rules.

If biofuel-based GHG emissions are included in DOH's rules (on a lifecycle basis), this makes $EC_{Biofuel} > 0$. Consequently, less oil can be burned within the generator to meet the fixed GHG cap and either more biofuel must be burned or overall generation must be reduced. Rearranging Equation (1) illustrates this relationship.

$$Oil \leq \frac{GHGCap}{EC_{Oil}} - \frac{EC_{Biofuel}}{EC_{Oil}} * Biofuel \quad (2)$$

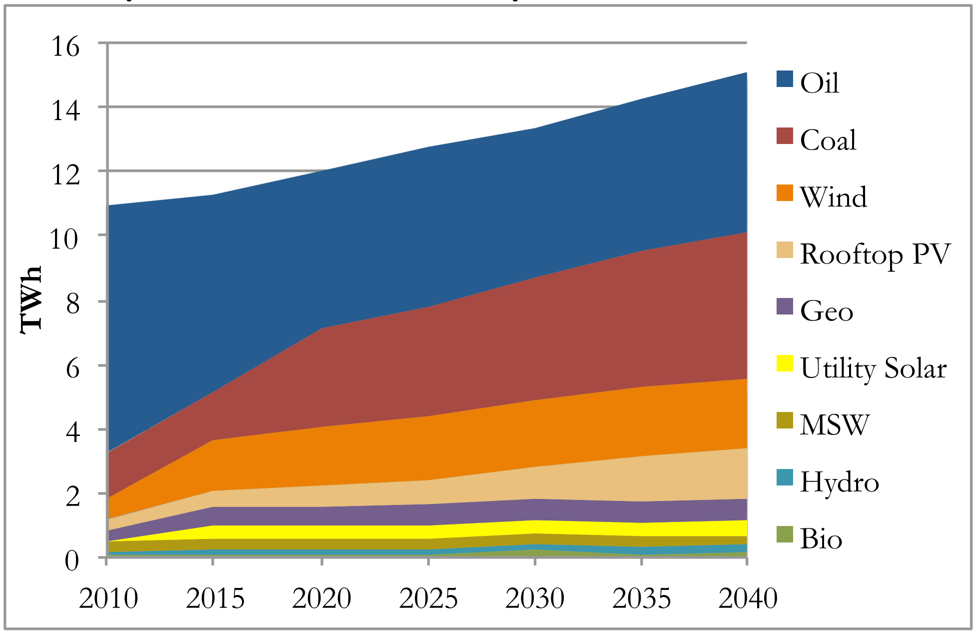
Equation (2) defines the maximum amount of oil that a unit can burn and still meet its cap. The smaller $EC_{Biofuel}$ is, the more oil the unit can burn and the less biofuel it needs to burn to meet its cap.

If we assume that biofuels will become less expensive than fossil fuels, then biofuels would completely displace oil-based fuels in these dual fired units as long as their emissions factor is less than that of their oil-based counterpart.

New Coal

Allowing new coal units to be built also significantly changes outcomes if the rules are implemented at the system-wide level. In the case with no partnering and the NSPS implemented at the unit level, no new coal can enter the system because its emissions rate exceeds that of the NSPS regulations. In fact, AES will be required to decrease generation. On the other hand, if there is partnering (thus allowing AES to maintain its current levels of generation) and the NSPS is implemented at the system-wide level as in Scenario 2, it would be cost-effective to build a great deal of new coal-fired generation. This is allowable under the assumption that new generation units are regulated under a system-wide NSPS – and it is based on a concentration threshold rather than an overall cap. The relative increase in coal-fired generation is shown in Figure 7 below.

Figure 7. Electricity Generation by Fuel/Technology (TWh)
Sensitivity Coal: New Coal Allowed, System-Wide Restrictions



The amount of new coal entering the system is restricted by constraints in the model that limit the amount of new coal-fired capacity that can come on-line over time. When a large amount of new coal enters the system, the cost of electricity generation declines. Costs and GHG emissions are shown in Table 12, in comparison to the case where there are system-wide restrictions, inclusion of biogenic sources of emissions, and exclusion of new coal units (i.e. the comparable case).[10]

[10] When there is system-wide partnering for DOH rules, the EPA's NSPS is implemented at the system level, inclusion of biogenic sources of emissions and exclusion of new coal units.

Table 12. Electricity Generation by Fuel/Technology
Costs and GHG Emissions New Coal Allowed in Comparison to No New Coal, System-Wide Restrictions

	New Coal	No New Coal
2040 Generation Total (TWh)	*15.1*	*15.1*
Oil	33%	54%
Coal	30%	10%
Wind	14%	14%
Rooftop PV	10%	10%
Geo	5%	5%
Utility Solar	3%	3%
MSW	2%	2%
Hydro	1%	1%
Bio	1%	1%
30-Year Total Cost ($B)	91	105
30-Year Total CO_2 Emissions ($MMTCO_2$)		
DOH CO_2 Accounting	206	186
Lifecycle Accounting	263	239
DOH CO_2 Acct + Lifecycle Biofuels	206	186

In comparison to its comparable case, the all-in cost of electricity generation over the 30-year time horizon declines by 15%. However, GHG emissions increase considerably – by 11% within the DOH CO_2 accounting framework. This result implies that if coal-fired generation were allowed today, then a baseline scenario with no DOH or NSPS regulations, emissions would be about 206 MMTCO2 and the cost to operate the system would be about $91 billion dollars. Therefore, the cost of disallowing coal-fired generation under system-wide DOH and NSPS regulations is about $14 billion dollars or about $700/ton of CO_2. This amounts to extremely costly abatement if a more stringent GHG cap were to be adopted at the State or Federal level in the future.

Fuel Prices

Major changes in fuel prices do not qualitatively change the impacts of Hawai'i's GHG policy. When fuel prices are *high*, there is more incentive to switch away from high-priced oil and biofuel and towards other renewable sources of energy, such as wind and rooftop PV (although capacity/grid limitations are a major binding constraint). In the *low* fuel price scenarios, the RPS is binding and renewable sources of energy account for approximately 40% of electricity sales between years 2030 and 2040 (in both the facility-level and system-wide restrictions). When oil prices are *high*, the effect of system wide versus facility-targeted implementation of the rules is more pronounced. When there are facility-level restrictions, 51% of electricity sales are met through renewable sources between 2030 and 2040. When there are system-wide restrictions, it is 42%. This is because facility-level regulation brings in more high-cost biofuels. Also intuitively, electricity generation costs increase when fuel prices are *high* and there is more incentive to reduce GHG emissions due to market forces. The opposite is true when fuel prices are *low*.

V. Discussion & Conclusions

We use a detailed model of Hawai'i's electricity sector to study the potential impacts of State and Federal GHG regulations. Given uncertainty about the final implementation and form of regulation, we adopt a scenario approach that brackets a range of possible outcomes. Scenario 1 assumes that there is no-partnering between facilities to meet the State's DOH proposed rules for existing units and the EPA's NSPS are implemented at the unit level for new units. In contrast, Scenario 2 assumes partnering, akin to a system of tradable permits, and that the NSPS are implemented at a system-wide level that includes all sources of new generation. Scenario 3 posits what might happen if the State's DOH proposed rules are extended to new facilities as well through the entire model time horizon (to 2040).

We find that implementing GHG rules at the facility level (Scenario 1) results in larger reductions in emissions but at relatively high cost. The cost of electricity production increases by $3 billion ($2007) from 2010 to 2040, and the cost of a ton of GHG abatement is $180, based on DOH's proposed GHG accounting framework. If biogenic sources of emissions are included in this framework, abatement costs rise to $340/ton.

With system-wide flexibility in meeting constraints (Scenarios 2 & 3), targets are achieved much more cost-effectively. In Scenario 2, there is not a meaningful difference from baseline conditions, meaning there is no additional cost to the electric sector. This is outside of transactions costs; such as the cost monitoring emissions and time spent negotiating partnerships. In Scenario 3, the cost of GHG abatement is estimated at $5/ton.

In sensitivity analysis, we find that the currently relatively high price of biofuels drives our results for bio-based generation if such emissions are accounted for in the DOH proposed rules. Assuming the aim is to meet the GHG regulation at least-cost and biofuels remain more costly than fossil fuels, then bio-based generation is not optimal and is not highly selected when there is flexibility in meeting goals. If GHG rules are implemented at the facility level, however, including lifecycle biofuel emissions can actually lead to the counter-intuitive result of increasing bio-based generation through partial repowering of existing oil-fired generators. However, if biofuel prices are lower than oil, then biofuels would displace oil and the emissions from existing units would be well below the GHG target. Since emissions from biofuel generation is below that of oil-fired generation even when including lifecycle bio-based emissions, the DOH rules would further strengthen the cost advantage of biofuels over their oil-based counterparts. It should also be noted that biofuels have wide ranging lifecycle emissions profiles. Setting an emissions factor to zero fails to differentiate among biofuels and does not incentivize burning the least carbon-intensive fuels (which is best promoted in the system-wide GHG cap).

This finding gives insight into how LNG might be encouraged or discouraged within the proposed GHG rules. Natural gas burns relatively cleanly, though on a lifecycle basis gas originating from LNG is substantively more GHG intensive than gas that was never liquefied and regasified (for example see Hondo, 2005) as well as depends on its overall production. By only considering out-of-stack emission for natural gas and because natural gas is expected to be less costly than oil (Facts Global Energy, 2012; EIA, 2013), introduction of LNG is likely to be encouraged under the proposed rules.

We find that rising fossil fuel prices provide a strong incentive to move towards renewable sources of energy and reduce GHG emissions. In the case that fuel prices substantively drop from current levels or there is large-scale fuel switching to a potentially lower cost fuel (such as LNG), this outcome might no longer hold. In addition, the RPS encourages a large-scale switch to renewable sources of energy. However, as shown in sensitivity analysis in regards to coal-fired generation, the RPS only governs the 40% sale of renewable energy and not the composition of the other 60%. This means that the RPS alone does nothing to limit the introduction of new coal. We find, however, that a facility-level NSPS effectively prohibits building new coal units, making "no new coal" policy compulsory rather than voluntary. If it is implemented at the system level, however, a large amount of new coal could still be built while meeting the overall GHG intensity level. If coal-fired generation were allowed today, then in a baseline scenario with no DOH or NSPS regulations, emissions would be about 206 MMTCO2 and the cost to operate the system would be about $91 billion dollars. Therefore, the cost of disallowing coal-fired generation in the future, under system-wide DOH and NSPS regulations, amounts to an extremely costly $700/ton of CO_2.

The implementation of DOH's proposed GHG rules and form of EPA's final NSPS is uncertain – including the interaction between the two. The current writing of DOH's proposed rules allow for partnering among affected facilities (economically akin to system-wide partnering or a system of tradable permits), though at *the discretion of the director*.

EPA's draft NSPS guidelines read as though they are more pertinent at the facility level or between like-technologies. If Hawaii is able to import LNG, then new oil or coal-fired generation could be produced under a system-wide NSPS program that is based solely on fossil-fired generation. If Hawaii decides to prohibit imports of LNG for electricity generation, then an NSPS program based on fossil-fired generation would preclude the running of any new oil or coal-fired generation because the emissions rate for these units exceeds the NSPS threshold of 1,100 lbs CO2/MWh.

Overall, we find that the high cost of Hawai'i's current electricity generation leads to a large-scale switch towards renewable energy, primarily wind and rooftop PV. With uncertainty in fuel prices, however, the qualitative findings about the impact of GHG policy remain robust. It is less costly to implement GHG restrictions with flexibility through a system – regardless of whether it's a concentration limit (most flexible) or a GHG cap (most environmental certainty). If a greater level of GHG emissions reduction is desired, the least-cost approach is to lower the level of the GHG cap while still allowing for the greatest flexibility in achieving targets system-wide. If policy is sufficiently stringent, GHG restrictions, particularly an overall cap, can act as a "backstop" policy by encouraging GHG emissions reduction in the case of lower fuel prices or fuel switching to another GHG-intensive fuel.

Future Inquiry

The proposed State GHG rules and NSPS apply to stationary sources of GHG emissions. This means that mobile sources, such as transportation, are excluded. In Hawai'i, transportation-based emissions accounted for approximately 51% of total emissions in 2007 (ICF International, 2008). Thus there is a distinction between the proposed State GHG rules and the requirements of Act 234. In future inquiry, we will examine transportation-based emissions as well to better understand whether or how the Act will be met.

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Appendix I

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) (U.S. 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.

$$\begin{aligned} z = e = \sum(t, DF(t) & \\ &* (\sum((f,g,b), FuelPrice(f,t) * HeatRate(g,f) * Gen(g,f,b,t) \\ &+ \sum\big((f,g,b), VOM(g) * Gen(g,f,b,t)\big) \\ &+ \sum((f,g,), FOM(g) * Cap(g,f,t)) \\ &+ \sum\big((f,g), CapCost(g) * Bld(g,f,t)\big) \\ &+ \sum((f,g)\$RePwrF(f), RePwrCst(g) * Bld(g,f,t)))) \end{aligned} \tag{1}$$

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
*Heat*Rate(*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:

$$\sum\big(f, Gen(g,f,b,t)\big) = G = MinCapFac(g,b) * BlkHr(b) * \sum(f, Cap(g,f,t)) \tag{2}$$

$$\sum\big(f, Gen(g,f,b,t)\big) = L = MaxCapFac(g,b) * BlkHr(b) * \sum(f, Cap(g,f,t)) \tag{3}$$

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.

$$MaxCap(g,t)Sum\big(f, Cap(g,f,t)\big) = L = MaxCap(g,t) \tag{4}$$

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.

$$\sum\big((g,f)\big), Gen(g,f,b,t)) * (1 - TrnLoss(p)) = G = \sum(c, Demand(c,p,b,t)) \tag{5}$$

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.

$$\sum((f,g))\$(mapg2p(g,p)), Cap(g,f,t) * (1 - derate(g))) = G = (1 + ReserveMargin(p)) * PeakDemand(p,t) \tag{6}$$

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.

$$\begin{aligned}\sum((g\$map2p(g,p), BlkHr(b) * \sum(f\$(mapf2g(f,g)), Cap(g,f,t)))) \\ - Mnt(g,b,t) = G \\ = (1 + OperRM(p)) \\ * \sum((f,g)\$(mapf2g(f,g)) and mapg2p(g,p), Gen(g,f,b,t))\end{aligned} \tag{7}$$

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.

$$Cap(g,f,t) = E = Cap0(g,f) + Bld(g,f,t)\$CapCost(g) - Ret(g,f,t) \text{ (t=2010)} \tag{8}$$

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:

$$Cap(g,f,t) = E = Cap(g,f,t-1) + Bld(g,f,t)\$CapCost(g) - Ret(g,f,t) \tag{9}$$

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

$$mapp2rps(p,rps), RPSCredit(g,f) * Gen(g,f,b,t)) = G = RPSTgt(rps,t) * Sum((f,b,g)Gen(g,f,b,t))$$

(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 CO_2. Though it could be expanded, currently HELM's emission constraints account only for CO_2 and are active only if an emissions target or emissions rate is specified for CO_2. 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)).

$$\sum\Big((f,g,b)\$\big(mapf2p(f,g) and EmisRate(f,\text{"TpMMBtu"})\big), EmisRate(f,\text{"TpMMBtu"}) * HeatRate(g,f) * Gen(g,f,b,t)\Big) + \sum\big((f,g,b)\$EmisRate(f,\text{"TpKWh"}) and, mapg2type(g,\text{"ZC"})\big) EmisRate(f,\text{"TpKWh"}) * Gen(g,f,b,t)) = L = EmisRateTgt(t) * \sum\big((f,g,b)\$mapf2g(f,g), Gen(g,f,b,t)\big)$$

(11)

$$\sum\big((f,b), EmisRate(f,\text{"TpMMBtu"}) * HeatRate(g,f) * Gen(g,f,b,t)\big) \leq EmisRateStandard(t) * \sum((f,b,), EmisRate(f,\text{"TpMMBtu"}) * HeatRate(g,f) * Gen(g,f,b,t)$$

(12a)

$$\sum\big((f,g,b)\$fossil\,unit(g), EmisRate(f,\text{"TpMMBtu"}) * HeatRate(g,f) * Gen(g,f,b,t)\big) \leq EmisRateStandard(t) * \sum((f,b,), EmisRate(f,\text{"TpMMBtu"}) * HeatRate(g,f) * Gen(g,f,b,t)$$

(12b)

Where:

EmisRate(f,"TpMMBtu") = Emissions rate for fuel *f* (metric tons of CO_2/MMBtu) for combustion units
EmisTgt(t) = Emissions target for CO_2 (millions of metric tons)
EmisRate(f,"TpkWh") = Emissions rate for non-combustion units (metric tons of CO_2/kWh).

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

	Mine to Plant	Plant + Combustion	Total (kg CO2/ kWh)	Total (MTCO2/ MMBtu)
Oil	0.013	0.085	-	0.098
Coal	0.005	0.109	-	0.11
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	-

Source: Estimates from GREET model 1.8d.1 (Argonne National Laboratory, 2010)

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.

$$MaxAsAvail(p,t) * \sum((f,g)\$\big(mapg2p(g,p)and, mapf2g(f,g)\big), Gen(g,f,b,t)) \geq \sum((f,g)\$\Big(mapg2p(g,p)and, mapf2g(f,g)and, \big(Windg(g)or, Solrg(g)\big)\Big) Gen(g,f,b,t)) \quad (13)$$

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.

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

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.