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HUMBOLDT COUNTY AS A RENEWABLE ENERGY SECURE COMMUNITY

Resource and Technology Assessment Report

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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Humboldt County as a Renewable Energy Secure Community: Resource and Technology Assessment Report is an interim report for the Humboldt County Renewable Energy Secure Community: Planning for Renewable-Based Energy Security and Prosperity in Humboldt County project (Contract Number PIR-08-034) conducted by the Redwood Coast Energy Authority. The information from this project contributes to PIER's Renewable Energy Technologies Program.

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ABSTRACT

This resource and technology assessment examines renewable energy development opportunities in Humboldt County, California. This work supports the development of a strategic plan for the Humboldt County Renewable Energy Secure Community project. The study explores the viability of using local renewable energy resources coupled with energy efficiency and other enabling technologies to meet the majority of the local electricity demand and a large portion of the county's heating and transportation energy needs.

A single-node energy dispatch model was developed to examine the temporal match between various supply-side resources and the aggregate Humboldt County demand. Numerous scenarios are evaluated based on their associated costs and their ability to meet energy demands and reduce greenhouse gas emissions. An optimization algorithm is employed to identify scenarios that can reduce greenhouse gas emissions at the least cost.

This study found that Humboldt County can meet the majority of its electricity demand and a large portion of its heating and transportation energy needs using local renewable resources while achieving a substantial reduction in greenhouse gas emissions at a modest cost increase. Key resources and energy technologies identified include biomass, wind, energy efficiency, electric vehicles, and electric heat pumps. Other California communities can use the models and tools developed and lessons learned to further their sustainable energy and greenhouse gas reduction efforts.

Keywords: Renewable, energy, secure, community, RESCO, local, resource, technology, assessment, cost, greenhouse gas, strategic, plan, grid, integration, dispatch, model, optimization, fuel switching, electric vehicles, heat pumps, California, Humboldt

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EXECUTIVE SUMMARY

Introduction

The Humboldt County Renewable Energy Secure Community (RESCO) project is an exploratory study intended to evaluate renewable energy opportunities in Humboldt County, California, and develop a strategic plan for their efficient and successful development. The stated goal of the Humboldt County RESCO project is to develop a strategic action plan for Humboldt County to develop its local renewable energy resources to meet 75 percent to 100 percent of local electricity demand, as well as a significant fraction of heating and transportation energy needs. A full range of resources and technologies are being considered that can meet the county's energy needs while maximizing environmental, economic, and social benefits. One key element of the Humboldt RESCO study, and the topic of this report, is an assessment of renewable energy resources and technology options.

Purpose and Objectives

The resource and technology assessment identified and explored the viability of using local renewable energy resources and demand-side energy technologies to efficiently meet Humboldt's renewable energy goals. A key issue was matching local electricity supply availability with local demand profiles. If there was a temporal mismatch in supply and demand, then energy import/export capabilities, energy storage assets, and/or demand management technologies were required to maintain stability on the electric grid.

The viability of various options was assessed according to a number of criteria, including:

- Providing adequate energy supply to meet projected demand.
- Using resource and technology options that are currently ready for commercial development.
- Using options that will function acceptably with Humboldt County's local electricity grid.
- Providing cost-efficient energy services.
- Providing environmental benefits, including cost-efficient reductions in greenhouse gas emissions.
- Providing local economic benefits in terms of jobs and economic output.

In addition, an effort was made to identify optimal combinations of various resource and technology options. The optimization analysis focused particularly on energy costs and greenhouse gas emissions.

Project Approach and Scope

A set of energy supply, demand management, energy import/export and energy storage scenarios was developed to meet the RESCO goal − provide at least 75 percent of local electricity demand and a significant portion of heating and transportation energy needs using local

renewables. Key tasks included identifying energy resource and technology options, assessing energy demands, and analyzing the ability of the energy resources and technology options to meet project goals. The work included the development and use of a customized energy balance and optimization model called the Regional Energy Planning Optimization (REPOP) model. The model is a single-node energy dispatch model that balances energy supply and demand on an hourly basis over a full year. As a single-node model, it ignores spatial characteristics and instead assumes all supply and demand occur at a single node. It was used to assess the ability of various supply portfolios to adequately meet demand, the overall cost of the supplied energy, and the resulting greenhouse gas impacts.

An optimization algorithm was used to identify optimal supply mixes coupled with energy technology solutions for given scenarios. The algorithm involved a set of constraints (e.g., supply must equal demand, cost must not exceed a certain amount) and an objective (e.g., minimize greenhouse gas emissions), as well as a method for searching through a large number of alternate energy supply mixes to find the optimal solution. For one of the potential scenarios, Pacific Gas and Electric (PG&E) staff conducted a steady-state power flow analysis to assess associated impacts to the local electric grid and to identify required infrastructure upgrades.

The renewable energy supply options for Humboldt County that were considered in the study are wind, wave, biomass, solar, biogas, and run-of-the-river hydro. Imported power and power generated by the new PG&E Humboldt Bay Generation Station were also considered. The new PG&E plant consists of ten 16 megawatt (MW) natural gas-fired internal combustion engine generators.

The demand-side technology options included energy efficiency and demand shifting, as well as fuel switching opportunities in the transportation and heating sectors. The technologies that enable fuel switching are electric vehicles (both plug-in hybrid and battery electric) for transportation and heat pumps for space and water heating. To help match energy supply to demand, centralized energy storage and transmission system capacity upgrades to the Humboldt electric grid were considered.

Hydrogen was considered as a means for powering the public transit fleet. Hydrogen is another way to fuel-switch from gasoline and diesel to electricity. The Argonne National Laboratory Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model was used to examine trade-offs between various forest biomass to transportation energy pathways. Biomass-fired power plants coupled with electric vehicles were compared with several forest-based biofuel production pathways.

Conclusions and Recommendations

Humboldt County has a wealth of local renewable energy resources. It is geographically isolated and severely constrained with regard to energy transmission capacity in and out of the county. Nearly all of Humboldt County's transportation fuels and the majority of its heating fuels are imported. Given these characteristics, the key issues Humboldt County faces in meeting its energy goals are not related to the adequacy of local resources, but instead to the

ability to develop these resources and the associated energy infrastructure needed to adequately serve demand with local renewable energy generation.

Key lessons learned in this study include the following:

- Humboldt County can meet 75 percent or more of its electricity needs and a large fraction of its heating and transportation demand using local renewable energy resources. This can result in a substantial reduction in greenhouse gas emissions and can be achieved at a modest cost increase.
- There are many possible resource and technology options to choose from, and a mixed portfolio of options will be more advantageous than any technology alone. Aggressive implementation of cost-effective energy efficiency opportunities should be a near-term pursuit. Biomass, wind, and small run-of-the-river hydroelectric energy sources should play a key supply-side role.
- The RESCO goal of meeting 75 percent or more of electric demand with local renewable resources may not be the best metric for measuring success. Instead of focusing on the percentage of electric energy demand served by local renewable resources, the authors recommend the focus be on cost-effective options to decrease overall greenhouse gas emissions across the whole energy sector.
- Fuel switching to plug-in hybrid and battery electric vehicles in the transportation sector and to electric heat pumps in the heating sector has the potential to play a major role in realizing the RESCO vision. Fuel switching opportunities are critical to cost-effectively achieving large reductions in energy-related greenhouse gas emissions. Without fuel switching, deep reductions in greenhouse gas emissions are infeasible.
- Humboldt County's RESCO goals can be achieved with only a modest cost increase. The majority of greenhouse gas reductions can be realized with only a 5 percent to 15 percent increase in overall energy costs, and beyond this level there are diminishing returns. With a cost increase of only 5 percent and a 40 percent penetration of electric vehicles and heat pumps, Humboldt County can achieve an 80 percent share of local renewable electricity and a 36 percent decrease in greenhouse gas emissions. Doubling the percentage cost increase to 10 percent can achieve a 95 percent share of local renewable electricity and a 43 percent decrease in greenhouse gas emissions.
- Distributed generation, like rooftop solar, can play a smaller but important role. These technologies can provide direct economic benefits to retail customers. In addition, they provide an active way for individuals and businesses to help implement the RESCO vision. Appropriate levels of support for these technologies can help cultivate broad backing for the overall RESCO plan.
- A steady-state power flow analysis conducted by PG&E indicates that substantial upgrades to the local transmission and distribution system will be required to accommodate large-scale development of local renewable energy sources.

- Energy storage will not likely play a significant role unless local renewable generation provides the vast majority (for example, greater than 90 percent) of local electricity demand.
- Regarding pathways for the use of forest-based biomass to provide energy for the transportation sector, the Fischer-Tropsch biodiesel pathway[1] compares favorably with the biopower to electric vehicles pathway[2], with both of these pathways achieving greater than 90 percent reduction in fossil fuel use and greenhouse gas emissions. The cellulosic ethanol pathway[3] does not fare as well in comparison.
- Opportunities for further research include:
    - Review, refine, and improve the Regional Energy Planning Optimization Program model, with subsequent adaptation of the model for use in another California community.
    - Identify and assess ways to cost-effectively and sustainably use forest fuel reduction material from remote locations as a fuel source.
    - Assess small hydroelectric opportunities and barriers in Humboldt County.
    - Conduct a more robust power flow analysis for the Humboldt area electric grid to include a transient stability analysis, as well as nonconventional means of meeting North American Electric Reliability Corporation (NERC) reliability standards such as energy storage facilities or curtailment of generation.
    - Conduct further research into the Fischer-Tropsch biodiesel forest-based biofuel pathway for using local biomass resources to meet transportation energy needs. Include further study into the cost and feasibility of this pathway.
- Benefits to California communities include:
    - Development of simulation models and planning tools for community energy and greenhouse gas reduction planning.
    - Lessons learned that can be applied to other communities.

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[1] The Fischer-Tropsch biodiesel pathway uses the Fischer-Tropsch process, a gas-to-liquids refinery process, to convert gaseous hydrocarbons, made from gasified woody biomass, into longer-chain hydrocarbons such as diesel fuel.

[2] The electric vehicle pathway uses woody biomass to fuel a rankine cycle steam power plant, thereby producing electricity that can be used to charge electric vehicle batteries.

[3] The cellulosic ethanol pathway converts woody biomass into ethanol via the biochemcial processes of hydrolysis and fermentation.

- A case study of how large percentages of local renewable resources coupled with the adoption of electric vehicles and heat pumps can lead to cost-effective reductions in greenhouse gas emissions and substantial local economic benefits.

CHAPTER 1: Introduction

1.1 Study Context

The Humboldt County Renewable Energy Secure Community (RESCO) study is a two-year planning study intended to evaluate renewable energy opportunities in Humboldt County and to develop a strategic plan for their efficient and successful development. The stated goal of the Humboldt County RESCO project is to develop a strategic action plan for Humboldt County to develop its local renewable energy resources in an effort to meet 75 percent to 100 percent of the local electricity demand as well as a significant fraction of heating and transportation energy needs. A full range of renewable resources is to be considered and a portfolio of supply and demand technologies is to be identified to best meet the county's needs and best capture associated environmental, economic, and social benefits.

One key element of the Humboldt RESCO study, and the topic of this report, is an assessment of resource and technology options. Additional elements of the study include an economic analysis, an assessment of development, financing and ownership options, an assessment of regulatory and political issues, and a stakeholder analysis. Key information obtained through these various work elements will be combined to inform the development of the Humboldt RESCO strategic plan. Separate study documents are being prepared for most of these key elements and a final report will integrate the full body of work.

1.2 Study Objectives

The purpose of this resource and technology assessment is to identify and explore the viability of using various integrated mixes of local renewable energy resources to meet most or all of Humboldt County's electricity needs and a significant portion of its heating and transportation energy needs in the year 2030. The viability of various options was assessed according to a number of criteria, including:

- Providing adequate energy supply;
- Utilizing resource and technology options that are currently ready for commercial development;
- Utilizing options that will function acceptably on Humboldt County's local electricity grid;
- Providing cost-efficient energy services;
- Providing environmental benefits, including cost-efficient reductions in greenhouse gas emissions; and
- Providing local economic benefits in terms of jobs and economic output.

The work documented in this report addresses all of these criteria. In addition, an effort was made to identify optimal combinations of various resource and technology options. The optimization analysis focused particularly on energy costs and greenhouse gas emissions. While local economic benefits were also considered, they are not discussed in this report. They are examined in detail in a companion document entitled *Humboldt County as a Renewable Energy Secure Community: Economic Analysis Report* (Schatz Energy Research Center, 2011).

1.3 Study Overview

The focus of this assessment is to identify a set of resources and technologies that efficiently meet Humboldt County's RESCO goals. This required the identification and assessment of local renewable energy resources along with key energy technology options that could help enable development of these resources. A key issue to be examined was the ability to match local energy supply and demand profiles. If there is a temporal mismatch in supply and demand then energy import/export capabilities, energy storage assets, and/or demand management technologies will be required to maintain stability on the electric grid.

Key tasks for this project included the identification of energy resource options, the identification of energy technology options, an assessment of energy demands, and an assessment of the ability of the energy resources and technology options to meet project goals. The assessment task involved the development and use of a custom energy balance and optimization model called the Regional Energy Planning Optimization Program (REPOP). The model is a single-node energy dispatch model that balances energy supply and demand on an hourly basis over a full year. This model was used to assess the ability of various supply portfolios to adequately meet demand subject to various constraints. In addition, the model was used to assess the overall cost of the supplied energy and the resulting greenhouse gas impacts. Finally, an optimization algorithm was used to identify the optimal supply mixes coupled with energy technology solutions.

Chapter 2 identifies the energy resource and energy technology options , and presents a description of the energy balance model. Chapter 3 presents the results of optimization modeling. Chapter 4 discusses the overall conclusions resulting from this assessment..

1.4 Background

Humboldt County has an electrical system that is geographically isolated from the larger California grid. It has a small electrical demand (170 MW peak), and a wealth of local renewable energy resources, including wind, wave and biomass. The *Humboldt County Energy Element Appendices: Technical Report* (Schatz Energy Research Center, 2005) found that Humboldt County's renewable energy resources could potentially meet all of the county's energy needs for electricity, transportation, and heating. Local biomass fired generators already support a third of the local demand. In addition, there are currently numerous renewable energy projects being considered for development. The largest of these is the Shell Wind Energy Bear River Wind Power Project, with a proposed installed capacity of 50 MW. Pacific Gas and Electric (PG&E) has recently re-powered a local natural gas fired power plant, and the new plant

consists of ten 16-MW high efficiency engine generators that are ideally suited to following changes in the intermittent supply of renewable electricity.

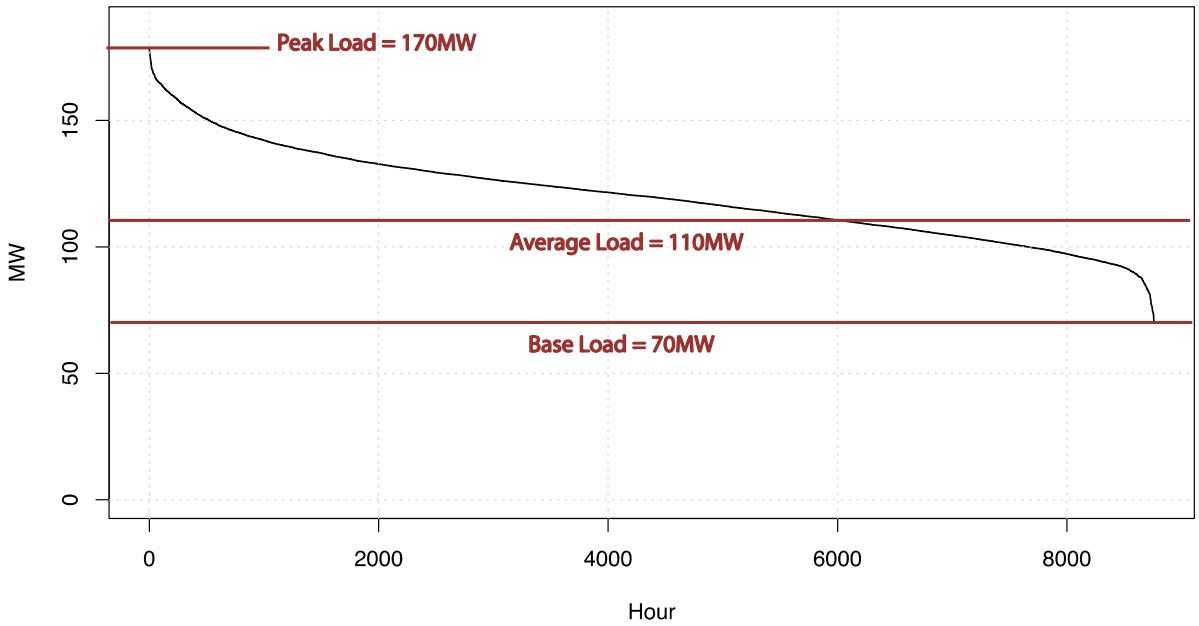
Humboldt County is geographically isolated and is almost an energy island. It has only one connection to the larger natural gas grid and four connections to the larger electric grid. The normally available capacity (approximately 60-70 MW) of the electrical transmission lines that connect Humboldt County to the larger grid is less than half of the County's 170 MW peak electrical demand. For this reason Humboldt County generates much of its own electricity. Although Humboldt County has a tremendous potential supply of indigenous renewable energy sources, it currently imports the majority of its energy in the form of natural gas and petroleum products.

1.4.1 Energy Use

In Humboldt County, energy is used as a transportation fuel and as electrical and heat energy in homes, businesses, industries, and agriculture. In 2008 it is estimated that Humboldt County's end-use energy consumption totaled about 18 trillion Btu's. Approximately half of the energy was used as a transportation fuel (gasoline and diesel), with large amounts also used to meet end-use electrical demands and end-use natural gas heating demands. Because of inefficiencies in the generation and transmission of electricity, the county's primary energy consumption totals about 25 trillion Btus. Primary energy sources were comprised mainly of natural gas, gasoline, diesel, and biomass (wood waste and firewood).

Humboldt County electricity use in 2008 totaled 990 GWh. This was used primarily in the residential, commercial, and industrial sectors. Lighting and refrigeration were the primary end-uses served in the residential and commercial sectors. The Humboldt area is winter peaking, with a peak demand of about 170 MW. Average demand is 110 MW, and baseload usage accounts for about 70 MW. Figure 1 shows a typical load duration curve for Humboldt County. Electricity use in Humboldt County increased by about 2.4 percent per year between 2004 and 2009.

Figure 1: Humboldt County 2008 Electricity Load Duration Curve



Source: Generated by Schatz Energy Research Center, data from PG&E.

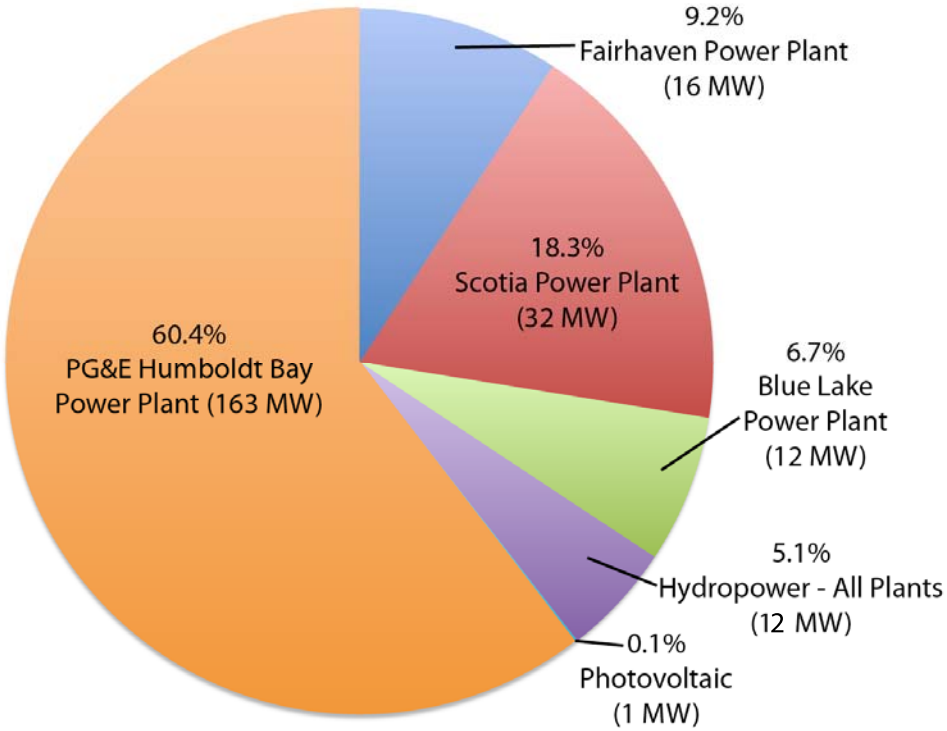
In Humboldt County, natural gas consumption in 2008 totaled an estimated 40 million therms. This usage does not include gas for producing electricity. More than half of the gas is consumed by the residential sector for home heating and cooking. The rest is consumed by the commercial, industrial, agricultural, and mining sectors.

Gasoline and diesel consumption in Humboldt County in 2008 was about 68 million gallons. The use of transportation fuels is closely linked to the number of vehicle miles traveled. Due to its rural nature, the county averages more vehicle miles traveled per capita than many more densely populated areas.

1.4.2 Energy Supply

The majority of primary energy used in Humboldt County is imported, with the exception of biomass energy. Essentially all of the county's transportation fuels are imported. Although the majority of electricity is generated in the county, a large portion of it is generated using natural gas. The county imports about 90 percent of its natural gas; the rest is obtained locally from fields in the Eel River valley. The county has the capability of generating all of its own electricity. In fact, in 2001 during the California electricity crisis, Humboldt County was a net exporter of electricity. Figure 2 shows an estimate of the breakdown of electricity sources serving Humboldt County in 2010. Three wood-fired power plants, Fairhaven, Scotia, and Blue Lake, provided 34 percent of the electrical energy needs. About 5 percent of electricity was supplied by small-scale hydropower (various plants each less than 3 MW). Finally, PG&E's Humboldt Bay Power Plant provided most of the remaining locally produced electrical energy.

Figure 2: Humboldt County 2010 Estimated Electricity Supply by Generator (Humboldt Bay fueled by Natural Gas; Fairhaven, Scotia, and Blue Lake fueled by wood biomass)



Source: SERC Staff, 2011

1.4.3 Renewable Energy Resources

It has been estimated that the total electricity generation from local renewable resources could provide as much as 1500 MW of generating capacity and over 6000 GWh per year of electrical energy (SERC, 2005). This includes power primarily from waves, wind, and biomass, with smaller contributions from small hydroelectric and solar. This is over six times the county's current electricity consumption rate. However, there is considerable uncertainty about how much of these resources can realistically be developed. For example, over 75 percent of the estimated renewable electricity resource would come from wave power, a technology that is in its early stages of development and therefore unproven. Even for well proven resources like wind, solar, and hydropower, there are many potential barriers that could impede development, including high costs, regulatory hurdles, lack of financing, siting and transmission access issues, and lack of public support. Nonetheless, the potential of these local resources is large and offers significant economic development potential.

1.4.4 Energy Transmission Infrastructure

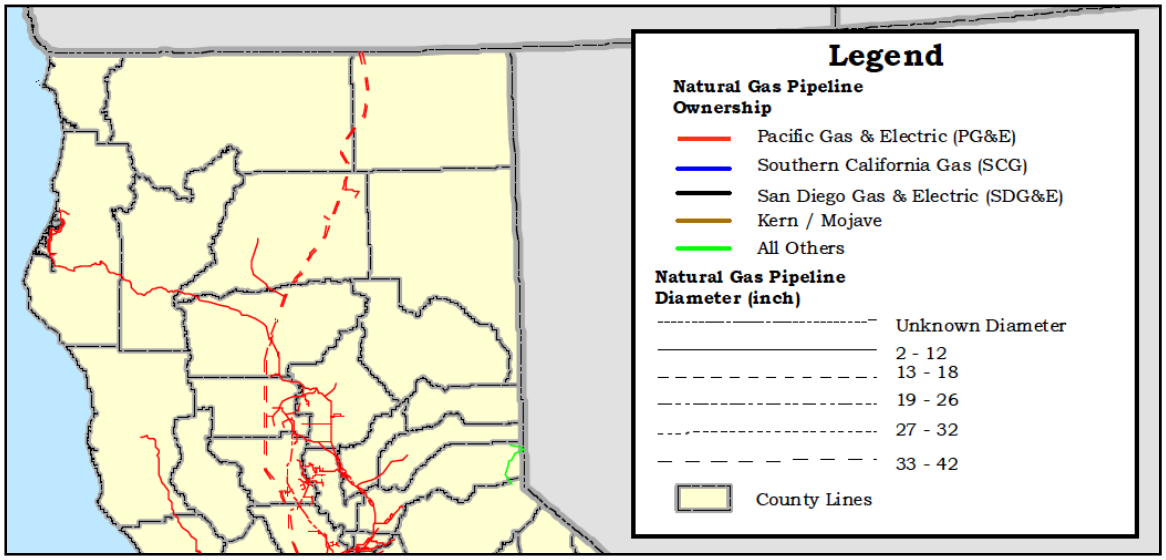
Humboldt County is remotely located at the end of the electrical and natural gas supply grids. PG&E owns the natural gas and electricity transmission and distribution systems in Humboldt County. There is one major natural gas supply line that comes from a compressor station in

Gerber in the Central Valley and follows a route roughly parallel to Highway 36 (Figure 3). This pipe is between two and 12 inches in diameter and according to PG&E is capable of transporting enough natural gas to meet current local needs. There are no gas storage fields in the local area, though there are some native gas fields in the Eel River Valley. It is estimated that approximately 65 to 70 percent of the households in Humboldt County have access to the natural gas grid (SERC, 2005).

The Humboldt area electrical grid covers about 3000 square miles and is connected to the bulk PG&E transmission system by four transmission circuits, each ranging from 31 to 115 miles in length (Figure 4 and Figure 5). Electricity imports are primarily transmitted through two 115kV circuits that come from the east at Cottonwood and follow a route roughly parallel to Highway 36 and Highway 299. Lower capacity circuits include a 60 kV circuit coming from the south at Bridgeville-Garberville (roughly parallel to Highway 101) and a second 60 kV line coming from Trinity County to the east that ties into the 115 kV lines. The total electrical transmission capacity into Humboldt County through the existing lines is 60 to 70 MW, less than half of the county's current peak demand. Therefore, local electrical generators are critical to meeting local electricity needs.

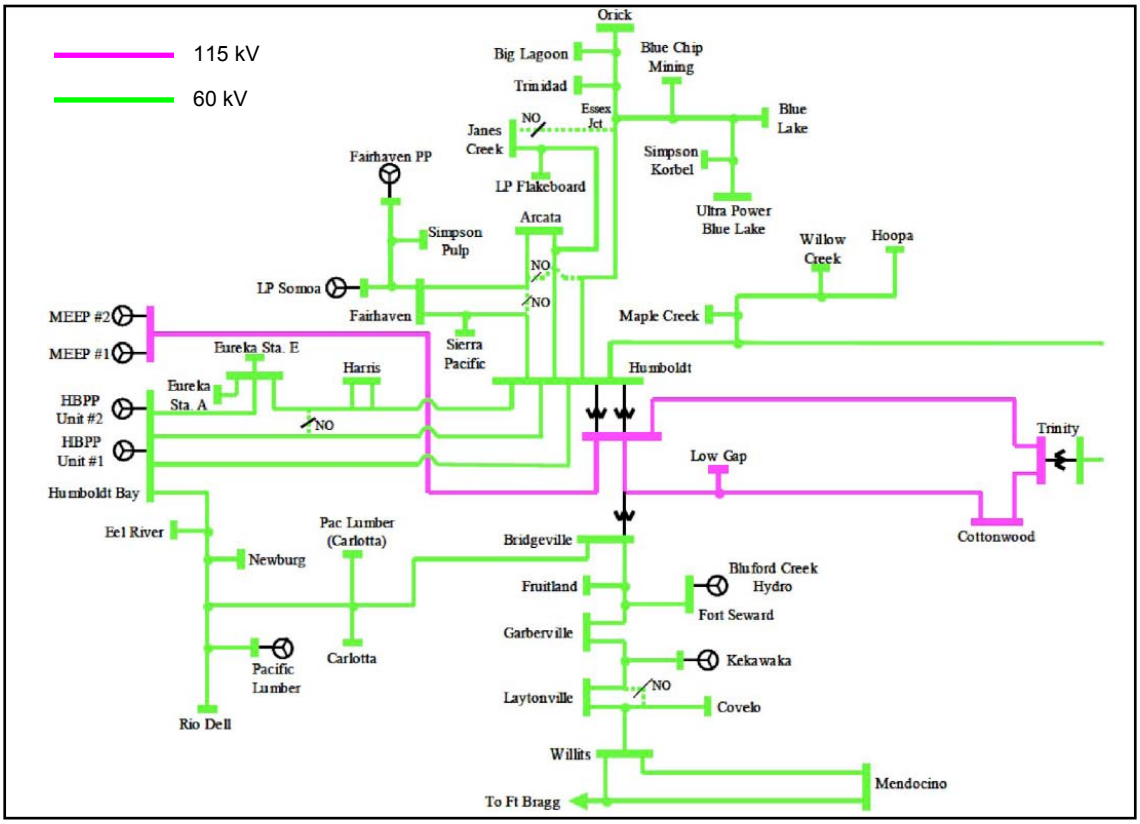
Humboldt County's connection to PG&E's larger electrical transmission grid serves many important functions. It supports wholesale market transactions and helps stabilize electricity prices, improves system stability and reliability, and provides additional voltage support. This connection allows electrical power to be imported, as well as exported.

Figure 3: Humboldt County Natural Gas Pipeline



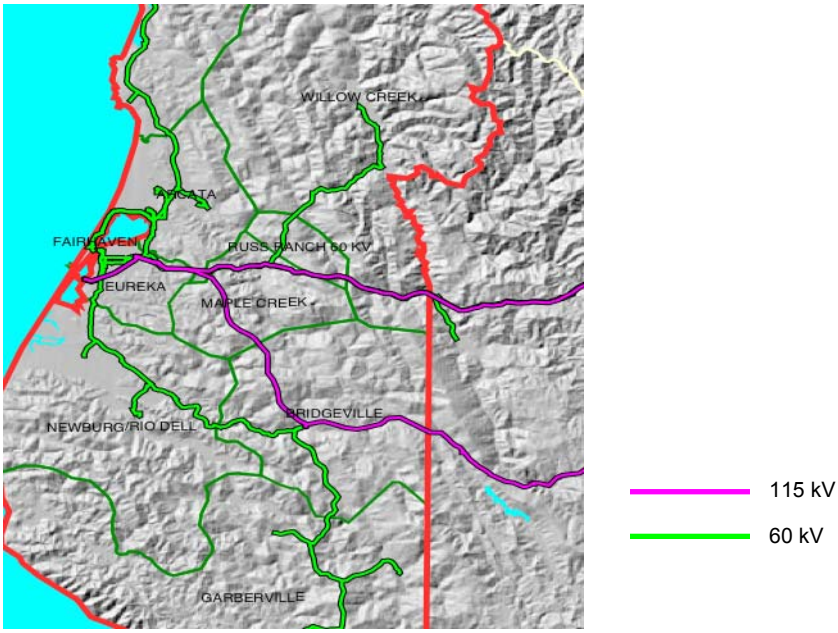
Source: Adapted from California Natural Gas Pipelines, California Energy Commission, Systems Assessment and Facilities Siting Division, Cartography Unit, http://www.energy.ca.gov/maps/natural_gas.html.

Figure 4: Humboldt Area Electricity Transmission Schematic



Source: Pacific Gas and Electric, 2005

Figure 5: Humboldt Area Electricity Transmission Map



Source: PG&E, undated.

CHAPTER 2: Approach

2.1 Overview

A resource and technology assessment was conducted to determine which local renewable energy resources and associated energy technologies can be used to meet Humboldt County's renewable energy goals. Accordingly, a set of energy resource, energy storage, and demand management scenarios were developed in an effort to provide at least 75 percent of local electricity demand and a significant portion of heating and transportation energy needs using local renewables. These scenarios were assessed for their technical feasibility according to their ability to meet projected energy demands in the year 2030. In addition, they were assessed based on their expected cost, greenhouse gas emission impacts, and economic impacts. For one potential scenario, PG&E staff conducted a steady state power flow analysis to assess associated impacts to the local electric grid and required infrastructure upgrades.

Section 2.2 identifies and characterizes renewable energy resources in Humboldt County and includes an estimate of their available capacity. Energy technology options are identified and characterized in Section 2.3, the Regional Energy Planning Optimization (REPOP) Model is described in Section 2.4, and the Power Flow Analysis conducted in partnership with Pacific Gas & Electric Company is introduced in Section 2.5.

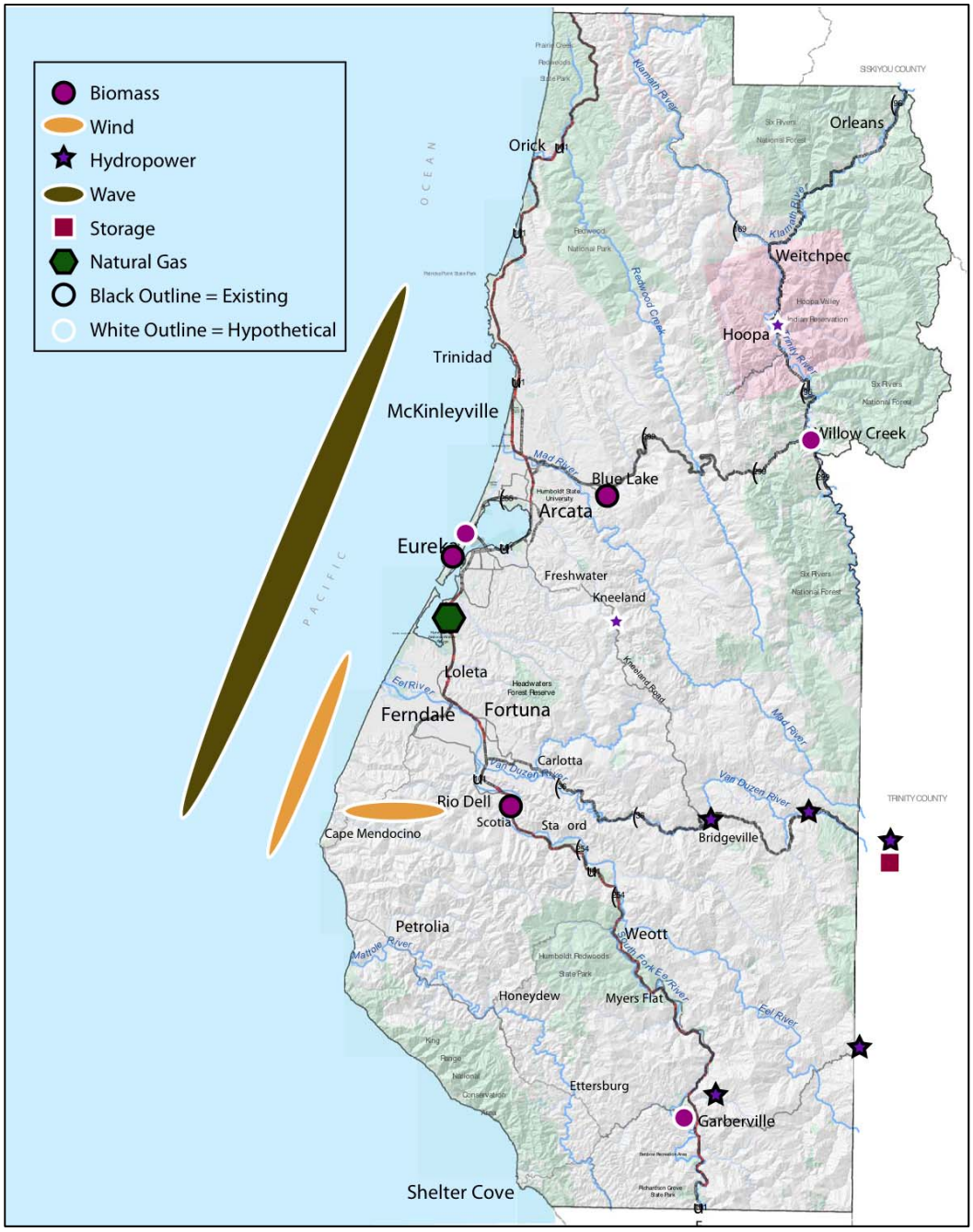
2.2 Energy Resource Options

Humboldt County is blessed with an abundant supply of renewable energy resources. Topping the list are wind, wave and biomass. In addition, run-of-the-river hydro and solar energy resources are also available in substantial quantities. To a lesser extent there are various biogas resources that can be accessed. Finally, Humboldt County possesses a significant supply of natural gas in Eel River Valley. Each of these resources is discussed briefly below. Figure 6 highlights existing as well as potential future sites for renewable electricity production.

2.2.1 Wind

Humboldt County's primary wind resource is located in the Cape Mendocino area. There is both a high quality onshore and offshore resource in this area. The onshore resource is rated at Class 5 or better and therefore exhibits good commercial potential. Shell WindEnergy, Inc. is currently pursuing the development of a 50 MW wind farm in this area on Bear River Ridge (Shell WindEnergy, Inc. 2007). It has been estimated that there is greater than 400 MW of onshore wind resource potential in this area (California Department of Water Resources, 1985). No other onshore geographic areas in Humboldt County exhibit potential for utility scale wind development. The maximum wind farm capacity examined in the REPOP Model was 250 MW. Offshore wind was not considered in the modeling analysis due to its inherent cost disadvantage compared to onshore development.

Figure 6: Existing and Potential Resources for Electricity Production in Humboldt County



Source: SERC staff.

2.2.2 Wave

Currently, wave energy technologies are relatively immature. Nonetheless, there is tremendous wave energy potential worldwide and tremendous interest in the technology. In 2003 the California Energy Commission completed a study (California Energy Commission, 2003) that

estimated the wave energy potential offshore from Humboldt County. Primary sites for the Humboldt County coastline north of Cape Mendocino (a 72 mile stretch) were estimated to have a total potential capacity of 3,900 MW. Primary sites for the southern Humboldt and northern Mendocino coastlines (an 81 mile stretch) were estimated to have a total potential capacity of 3,700 MW, approximately half of which falls within Humboldt County's coastline. A conservative estimate is that as much as 1,000 MW of this potential capacity could be developed (SERC, 2005). PG&E recently considered development of a 5 MW wave energy pilot project directly west of Humboldt Bay (PG&E, 2010a). Although this project has been suspended, future development of wave energy potential on the Humboldt County coastline continues to be a real possibility. The REPOP Model was used to examine the potential for wave energy development as large as 100 MW in capacity.

2.2.3 Biomass

The primary biomass resource in Humboldt County is forest biomass. Humboldt County is fortunate to have a tremendous forest resource base, with 1.9 million acres (65 percent private) of forested land covering more than 80 percent of the county's land area (Humboldt County, 2005). The timber harvest volume in Humboldt County in 2000 was 389,000 million board feet. This accounted for 20 percent of the timber harvest volume in the state, ranking Humboldt County as the number one county in the State with almost twice the harvested volume of second ranked Siskiyou County (Laaksonen-Craig, Goldman, and McKillop, 2003).

Humboldt County has historically obtained a large portion of its electricity from wood-fired, Rankine cycle steam power plants. Currently there are three operating wood waste-fired power plants in Humboldt County: the 32 MW Town of Scotia Company, LLC power plant (formerly Pacific Lumber), the 16 MW DG Fairhaven Power, LLC power plant, and the 12 MW Blue Lake Power, LLC (formerly Ultrapower) power plant. The Fairhaven plant sells all of its electricity to PG&E under a long-term contract that extends to 2017. The Scotia plant provides electricity for the town of Scotia and the Humboldt Redwood Company sawmill, and excess electricity (approximately 80 percent of what is generated) is sold to PG&E under a long-term contract. Power from the Blue Lake power plant is sold under long-term contract to San Diego Gas & Electric Company. These three operating plants currently provide between a third and a half of Humboldt County's total electricity needs.

Biomass fuel currently comes from wood waste from mill operations and forest slash left over from timber harvest operations. Another potential source is residue from forest fuel reduction programs aimed at minimizing forest fire hazards. While most sources of sawmill waste are currently being utilized, there may be room for expansion of biomass power production if woody biomass from forest fuel reduction efforts can be economically utilized.

Our estimate of the available biomass resource comes from the findings of the California Biomass Collaborative (Williams, 2008), which was reported without modification from estimates developed by the California Department of Forestry and Fire Protection. The forest biomass available for fuel use in Humboldt County for the period 2007-2020 is estimated to be 1,314,000 bone-dry tons per year. This resource is distributed between forest thinnings (48 percent), forest slash (31 percent), and mill residue (21 percent). Logging slash comprises

branches, tops and other materials left on the ground after harvest. Forest thinnings are non-merchantable materials removed during harvest activities and include understory brush, small diameter trees, and other material that cannot produce saw logs. Thinning is designed to reduce crowding and enhance overall forest health and fire resistance. Thinning resources exclude materials from forest reserves, stream management zones, coastal protection zones, and steeply sloped lands (greater than 30 percent to 35 percent slope). Sawmill residues are a by-product of milling operations and are already utilized for energy production or other non-energy uses. Williams (2008) estimates that Humboldt County forest biomass residues are capable of supporting 222 MW of electricity generation capacity. The maximum biomass capacity examined in the REPOP Model is 225 MW.

2.2.4 Hydro

There are currently six small hydroelectric facilities that serve Humboldt County (SERC, 2005). These facilities have a combined rated capacity of 11.5 MW. All but one of these, The Mathews Dam facility at Ruth Lake, are run-of-the-river systems. All of these systems are 5 MW or less in capacity and all of them sell power to Pacific Gas and Electric Company via long-term contracts. Although numerous other sites totaling about 60 MW in capacity have been identified for potential development of small, run-of-the-river hydroelectric power (Oscar Larson & Associates, 1982), very few sites have been developed. Likely barriers to small hydropower development include rigorous permitting requirements, remote site locations, and lack of economic viability. That said, significant potential for expansion of small hydropower exists in Humboldt County. A maximum biomass capacity of 38 MW of small hydroelectric power was examined in the REPOP Model.

2.2.5 Solar

Humboldt County is not well suited for large, utility-scale solar energy installations, including photovoltaic and concentrating solar thermal electric. The solar resource is not adequate to make such an installation economically viable, and there are few areas with large expanses of flat, available terrain. Most of the flat areas are in the foggy coastal parts of the county (near the Humboldt Bay and Eel River deltas), which are the population centers.

Rooftop solar electric and solar hot water systems that serve individual facilities can be very appropriate in Humboldt County. On a per capita basis since 1998, the residents of Humboldt County have installed over twice as many grid-connected solar electric systems as the State of California as a whole. The total grid-connected capacity in 2010 was 1.44 MW for 428 systems (California Energy Commission, 2010a).

The average solar resource in the coastal areas of Humboldt County is 4.4 kWh/m2/day for a surface sloped at latitude (41°) and facing due south. A maximum cumulative solar electric system capacity of 10 MW was examined in the REPOP Model.

2.2.6 Natural Gas

There are natural gas deposits in Humboldt County in the Eel River basin. As of 2005, there were 38 producing wells and 15 shut-in wells in the county. Shut-in wells cannot produce gas at

their existing depths and are sealed off to maintain the pressure on remaining deposits. Total net gas production in the county in 2003 was 1,040,000 MCF. The active gas wells are concentrated in the Tompkins Hill gas field, where there are 31 producing wells. In county production in 2003 was enough gas to supply approximately 11 percent of Humboldt County's total natural gas needs that year. The peak production for the Tompkins Hill field has passed. Current production rates are barely one half what they were in 1992 when net production was 1,930,000 MCF (thousand cubic feet) (California Department of Conservation, 2003). There were 10 new exploratory wells drilled in recent years in the Alton area where there are two new producing wells (Wheeler, 2005). The size of the natural gas reservoir in the Alton area is still unknown and data being collected is proprietary. All of the active gas wells in Humboldt County are dry gas wells and are not associated with oil deposits.

Natural gas is also supplied to Humboldt County via a gas transmission pipeline, as discussed in Section 1.4.4.

2.2.7 Natural Gas-Fired Power Plant

The Humboldt Bay Generating Station is a 163 MW power plant located on the eastern shore of southern Humboldt Bay in King Salmon. It is owned and operated by Pacific Gas and Electric Company and was first brought online in 2011. It consists of ten 16.3 MW natural gas fired engine generators made by Wartsila. The generators have an overall thermal efficiency rating of 45 percent. They are operated individually and can be used to closely follow changes in demand and changes in the supply of local intermittent renewable resources. They can be ramped up from a warm standby state to full power in 10 minutes. These generators are able to provide all of the local reserve capacity that is needed for the Humboldt Area. The Humboldt Bay Generating Station is included as one of the electricity supply resources in the REPOP Model.

2.2.8 Biogas

Additional sources of biomass-based fuel in Humboldt County include biogas from numerous resources. These include anaerobic digester gas from wastewater treatment plants and/or food waste digesters, landfill gas, and dairy biogas. These projects are not likely to make a large contribution toward meeting the county's electricity needs as the electricity production from all of these sources combined is unlikely to generate more than about 1 MW in the best of circumstances. Nonetheless, these projects are likely to be small-scale community based efforts that will have strong local support. As such, they represent some good potential near-term projects for the Humboldt RESCO strategic plan.

A food waste digester project currently being proposed by the Humboldt Waste Management Authority could generate up to 300 kW (Humboldt Waste Management Authority, 2010). The project would involve the creation of a local food waste collection program and would require strong participation from area restaurants, food vendors, and other food waste generators. Food waste would be digested adjacent to the Eureka wastewater treatment plant facility and digester gas would be added to the wastewater treatment plant's digester gas stream. Project benefits will include a reduction in the solid waste stream, monetary savings and greenhouse gas reductions in addition to renewable energy generation. Environmental documents for this

project have already been completed and preliminary project development is under way. A pilot food waste collection program is being used to determine the cost of collection and the most efficient collection strategy, as well as to establish partnerships with commercial and industrial food waste generators. Additional work underway involves digester procurement, property rezoning, assessment of site suitability and negotiations for site control.

Humboldt Waste Management Authority is also pursuing a landfill gas to energy project at the Cummings Road Landfill that could power a 250 kW generator. In April 2011, they released a Request for Proposals for the development of the landfill gas resource. In July 2011, the Waste Management Authority Board approved a contract with Flex Energy to develop the resource. This approval was subject to a number of contingencies, including: clarifying the costs associated with interconnection to the electricity grid, site development, and permitting. Other contingency efforts include further evaluation of the landfill gas resource, assessment of system durability, and researching agreements for selling electricity and using the waste heat. Once these contingencies have been fully addressed the project economics will be reassessed and, provided the project is still cost-effective, the Humboldt Waste Management Authority will proceed with the contract to install a Flex Energy Powerstation.

Regarding power generated from anaerobic digester gas from wastewater treatment plants, Humboldt County has four facilities that may be large enough to justify electrical power generators (SERC, 2005). The Eureka wastewater treatment plant already operates a 95 kW generator powered by anaerobic digester gas. Three additional wastewater treatment plants offer power production potential of 20 to 30 kW each and include the plants for the cities of Arcata, Fortuna and McKinleyville. Economic feasibility for each of these facilities is uncertain.

Finally, power generation from dairy biogas does not appear very promising for Humboldt County dairies because of their small size and pasture-based operations (Reis and Engel, 2003). If a biogas digester system were installed for a local dairy operation the typical generator size would likely be about 25 kW.

Note that these various biogas resources are not considered in the REPOP Model due to their small cumulative capacity.

2.2.9 Heating Fuels

Heating fuels in Humboldt County predominantly include natural gas (discussed in Section 2.2.6), propane, and firewood. All propane is trucked into the County. In 2003, an estimated 5.8 trillion Btus of heating energy were used in Humboldt County for space heating, water heating and other uses (SERC, 2005). Of this total, 85 percent was in the form of natural gas, 9 percent in the form or firewood, and the remaining 6 percent in the form of propane.

2.2.10 Transportation Fuels

Essentially all transportation fuels are in the form of diesel and gasoline and are imported into the county via barge to the Chevron petroleum terminal in the south end of Eureka. In 2003 nearly half of Humboldt County's end-use energy (8.52 trilling Btu's) was used in the form of

gasoline and diesel fuels. This amounted to 54.6 million gallons of gasoline and 16.8 million gallons of diesel fuel (SERC, 2005).

2.3 Energy Technology Options

It is anticipated that the addition of various energy technologies may be necessary or desirable to effectively integrate large-scale development of renewable energy resources into the Humboldt County electric grid . For example, energy storage may be required to buffer intermittent renewables. Similarly, growth in local electric demand can be used to absorb additional generation from local renewable resources. In particular, fuel switching in the transportation sector by converting to electric vehicles and in the heating sector by converting to electric heat pumps may prove beneficial in reducing greenhouse gas emissions while also making use of local renewable energy sources.

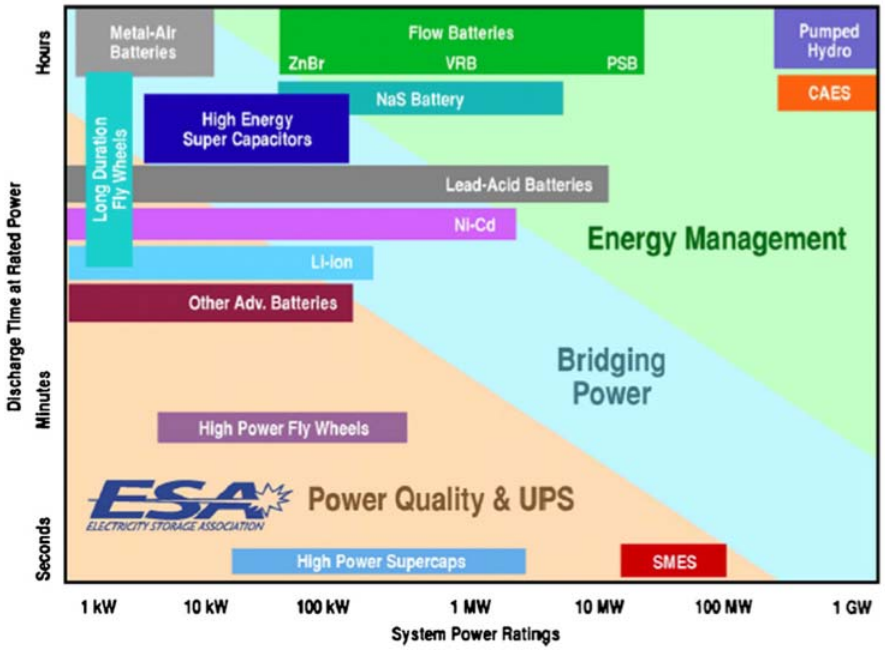
This section of the report identifies and describes various energy technology options that have been considered as part of the Humboldt RESCO study. Where detailed analyses were required to develop the required input to the REPOP Model, a summary of the information is presented here and greater detail is provided in associated appendices.

2.3.1 Energy Storage

A significant challenge to achieving high penetrations of renewable energy on the electric grid can be the variable and intermittent nature of some renewable resources. For example, solar and wind energy cannot be dispatched to match fluctuating demands, but instead must be utilized when available. A mismatch between the availability of these resources and the demand for electricity can result in supply deficits or surpluses that cannot be used. Energy storage provides a solution to this issue by decoupling the timing of resource availability from resource use, allowing electric power to be stored and released when needed.

Initial simulations of high levels of renewable energy penetration in Humboldt County suggest that energy spillage due to surplus intermittent renewable energy may occur frequently throughout the year. The term “spillage” refers to available renewable electricity that cannot be used due to a lack of adequate demand and capacity for export. This curtailed power is estimated to range from about 5 MW to 20 MW for durations of two to three days at a time. This suggests the need for an energy storage solution with a capacity of 240 MWh to 1440 MWh. As shown in Figure 7, pumped hydroelectric energy storage, compressed air energy storage (CAES) and various battery energy storage technologies are suitable for energy storage applications requiring these power and stored energy characteristics. The REPOP Model considered a maximum charge/discharge capacity of 25 MW and a maximum energy storage capacity of 18 GWh (enough energy to discharge for 30 days) at a cost of 1.25 million $/MW of capacity. These assumptions are based on data associated with pumped hydroelectric storage. Appendix D.2.2 presents a full discussion of the storage technology assessment as well as the treatment of energy storage in the REPOP Model.

Figure 7: Distribution of Energy Storage Technologies as a Function of Field Application



Source: Electricity Storage Association (2010)

2.3.2 Fuel Switching − Transportation

2.3.2.1 Electric Vehicles

Electric drive vehicles have the potential to substantially displace gasoline and diesel demand with the use of cleaner, locally generated electricity. Compared to conventional gasoline and diesel, which is entirely imported, the majority of electricity consumed in Humboldt County is generated by local natural gas and biomass fired power plants. Studies indicate that electricity generation from fossil fuels such as natural gas and even coal is cleaner than the combustion of gasoline and diesel (EPRI, 2007). Moreover, electricity generated from local renewable sources can further reduce greenhouse gas (GHG) emissions. Electric drive vehicles represent a fuel switching option that can reduce GHGs and allow greater use of local renewable energy resources.

The term electric vehicle (EV) is used throughout this report to refer to both plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs). Electric vehicles can derive part or all of their propulsion power from electricity stored in an on-board rechargeable battery. This has two primary benefits: electricity can be generated domestically and an electric motor is more energy efficient than an internal combustion engine.

PHEVs incorporate a drive train architecture that includes both an internal combustion engine (ICE), powered by gasoline or diesel, and an electric motor. A PHEV can be propelled by its ICE, its electric motor, or a combination of the two. The vehicle's all-electric range refers to the number of miles that can be traveled using only electricity from a single battery charge while in charge-depleting mode. For travel beyond a PHEV's electric range, the vehicle operates in

charge-sustaining mode and is powered by its ICE. Depending on PHEV architecture, some driving events, such as aggressive acceleration, may cause the vehicle to simultaneously demand power from both its electric motor and ICE (blended-mode). Examples of PHEVs include the Chevrolet Volt and Toyota Prius Plug-In, with advertised all-electric ranges of 40 miles (PHEV-40) and 13 miles (PHEV-13), respectively. PHEVs provide a flexible alternative to conventional vehicles because they can meet the typical energy required for daily commuting with electricity, while relying on gasoline for extended travel.

In contrast to a PHEV, a BEV is solely propelled by an electric motor and powered by electricity, with no reliance on an ICE. A BEV generally has a larger battery capacity since its travel distance is limited to the energy available in a single battery charge. The Nissan Leaf is a BEV with an advertised all-electric range of 100 miles. While a BEV's lack of an ICE makes it a zero emissions vehicle (ZEV), it is reliant on the development of a rich charging infrastructure for extended travel and to reduce consumer range anxiety.

To assess the potential impacts of electric vehicles in Humboldt County, the literature was consulted and a technical assessment was conducted. Only light duty conventional vehicles (vehicles classified as autos or light trucks by the California Department of Motor Vehicles) fueled by gasoline were considered for replacement by an electric vehicle. Key tasks included establishing a baseline, projecting the future adoption of electric vehicles, characterizing vehicle performance, and estimating vehicle charging power requirements. The methodology and results are described in detail in Appendix A. An economic benefit/cost analysis was also conducted as part of the RESCO study and is presented in SERC (2011).

2.3.2.2 Hydrogen Vehicles

Another way of meeting transportation energy demands with local renewable energy resources is to produce hydrogen fuel. The most likely hydrogen production pathway would be electrolysis utilizing local renewable electricity. This fuel could then be most efficiently utilized in hydrogen fuel cell vehicles. This pathway would directly compete with the electric vehicle pathway, as the local renewable electricity could be used to either charge electric vehicle battery packs or produce hydrogen. In this regard, EVs have numerous advantages over hydrogen fuel cell vehicles. EVs are currently becoming commercially available, whereas hydrogen fuel cell vehicles are still several years away from commercial release. EVs are likely to be cheaper than hydrogen fuel cell vehicles, at least in the near-term. EVs make more efficient use of the available renewable electricity (plug-to-wheel efficiency for a modern EV, like the Nissan Leaf, is likely to be about 0.24 kWh/mi compared to a hydrogen fuel cell vehicle running on electrolytic hydrogen at 1.0 kWh/mi.) And finally, the infrastructure requirements for hydrogen production and fueling are likely to be somewhat more demanding than the required electrical system infrastructure upgrades required to support EVs. For all of these reasons hydrogen fuel cell vehicles were not considered in the REPOP model.

There are, however, market niches where hydrogen fuel cell vehicles may out-compete EVs. These include vehicle applications that demand long distance driving. For example, the Toyota Highlander Fuel Cell Hybrid Vehicle advanced (FCHV-adv.) has a range of 400 miles compared to the Nissan Leaf BEV with a range of only 100 miles. In addition, fuel cell vehicles can be

refueled in a few minutes, not the hours that are required to recharge an EV battery. Most major car companies (Toyota, Honda, GM, Hundai, and Daimler) have major fuel cell vehicle programs.

Fuel cell vehicles also outperform EVs in heavy-duty vehicle applications, like for transit buses. All electric vehicles are not being proposed for full-size transit applications, whereas hydrogen fuel cell buses are being successfully used in these applications. The Humboldt RESCO study examined the use of hydrogen fuel cell powered transit buses. This is a niche application that accounts for about 1.5 percent of the county's diesel fuel consumption. The analysis considered the development of hydrogen infrastructure capable of handling 10 to 100 percent of transit needs and examined the resulting cost and greenhouse gas emission implications. It was assumed that hydrogen fuel would be generated via electrolysis. Details for the methodological approach are given in Appendix B.1 and the results of this analysis are presented in Section 3.3.

2.3.2.3 Forest-Based Biofuels

Humboldt County has a tremendous forest biomass energy resource. Currently a large portion of this resource is used to fuel steam-fired power plants, thereby generating electricity. If the use of this resource were expanded, a portion of the added electricity could be used to charge electric vehicles. However, an alternate pathway for using forest biomass energy resources to power the transportation sector would be to produce forest-based biofuels. Two forest-based biofuel options are cellulosic ethanol and Fischer-Tropsch biodiesel. These alternate pathways were explored and compared with the biopower to electric vehicle pathway in terms of energy efficiency and greenhouse gas emissions using the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. GREET is a software tool developed by Argonne National Laboratory to fully assess the lifecycle, or well to wheels (WTW) energy and emission impacts of various vehicle and fuel combinations. GREET calculates total energy consumption, GHG emissions (CO_2, CH_4, N_2O), and criteria pollutant emissions (VOCs, CO, NO_x, PM10, PM2.5, and SO_x). This analysis was conducted independent of the REPOP Model optimization exercise.

To conduct the fuel pathway comparison, the spreadsheet-based version of the GREET model was used as opposed to the graphical user interface version. This allowed for more control over a wider range of model parameters and visibility of underlying model calculations. Default GREET parameter values were assumed during model runs with a few exceptions, which are listed in Appendix B.2.3, Table 23. These parameters were updated primarily to specify a common biomass feedstock (forest residue) for all fuel pathways and to reflect Humboldt County's electricity generation mix. Ethanol yield via fermentation was also updated according to the literature since a comment in the GREET model explained that the default value was not well researched and should not be used.

A complete description of the technical assessment of electric vehicles can be found in Appendix A. For comparison to biofuel conversion processes, it was assumed that all marginal electricity required to power EVs would come from the combustion of biomass. From a greenhouse gas perspective, electricity generated from sustainable biomass harvesting is

generally considered to be carbon neutral, and it is treated as such in this analysis. Electric vehicle emissions directly depend on vehicle type (PHEV or battery electric vehicle (BEV)), its all-electric range, and the generation source of its electricity. The average daily distance traveled per vehicle in Humboldt County is approximately 30 miles. A PHEV with a lower all-electric range (for example PHEV 10) will consume more gasoline and emit more GHG emissions than a PHEV with a higher all-electric range (for example, PHEV 40). A BEV is a zero emissions vehicle when powered by biomass generated electricity.

The two forest-based biofuel options examined in this study are Fischer-Tropsch biodiesel and cellulosic ethanol, as these technologies are the most effective at utilizing lignocellulosic biomass. In Humboldt County it is estimated that lignocellulosic feedstocks, those derived from woody biomass in the forestry sector, account for 94 percent of the technically available biomass (Williams et al., 2007). Appendix B.2 presents a detailed description of these technologies; the results of the analysis are summarized in Section 3.4 and presented in detail in Appendix B.2.3.

2.3.3 Fuel Switching − Heating

Another area where fuel switching can be used to replace the consumption of imported fossil fuels with the use of local renewable energy sources is in the space heating sector. Currently the majority of energy used for space heating in Humboldt County, over 80 percent, comes from natural gas (Schatz Energy Research Center, 2005). A smaller portion comes from propane (approximately 9 percent), with the remainder coming from firewood. With large-scale renewable electricity development in Humboldt County, a portion of this heating energy demand could be served using renewable electricity and electric heat pumps. Heat pumps are devices that utilize an electrically driven vapor-compression refrigeration cycle (like a refrigerator or air-conditioner) to move heat from a colder reservoir to a warmer reservoir.

When using heat pumps for space heating applications heat is either moved from the outside air (an air source heat pump) or from the ground (a ground source heat pump) to the interior conditioned space. The efficiency of a heat pump can be expressed as the coefficient of performance (COP), which is the ratio of useful heat moved into the conditioned space to the amount of electrical energy required to move the heat. A typical air source heat pump has a COP of about 3, whereas a typical ground source heat pump has a COP of about 4.

This study employed a highly conservative approach in estimating the cost of switching from natural gas furnaces to heat pumps. The total cost for heating service in Humboldt County was assumed to include the cost of fuel plus the installed cost of a geothermal heat pump system. This assumption neglects the fact that air source heat pumps, which cost considerably less than ground source units, are generally more appropriate in Humboldt County due to the mild climate (California Energy Commission 2010b). In addition, the cost of replacing existing natural gas heating equipment was ignored. This implies the that there will be an early replacement of the natural gas heating equipment as opposed to a replace of the equipment at the time of failure. Finally, a coefficient of performance of 3 was used in the analysis, which is a conservative performance estimate. Ground source heat pumps generally have a coefficient of performance of about 4 (U.S. Department of Energy (DOE) 2010). The lower coefficient of

performance results in more electricity consumed and therefore greater cost to meet a given heating demand.

2.3.4 Energy Efficiency

Improvements in energy efficiency can substantially reduce energy demand in Humboldt County. While there are no detailed Humboldt County specific estimates of energy efficiency potential and associated costs, there is a wealth of literature at the state level. The most recent and authoritative of these reports is the *California Energy Efficiency Potential Study* by Itron, Inc. (2008).

The Itron (2008) study quantifies yearly (2007-2026) energy savings potential and associated costs by investor owned utility service territory, California Energy Commission climate zone, consumption sector, building type, end-use category, fuel type (electricity or natural gas), and efficiency measure type. The sectors and end-use categories included in the analysis can be seen in Table 1. Each end-use category is comprised of a number of efficiency measures that provide energy savings above a common base technology.

The Itron (2008) study assessed statewide technical, economic and market potential for energy efficiency measures. This study considers only market potential and examines a range of incentive levels, starting with a base incentive and increasing up to the full measure cost. The total savings potential from the statewide study was scaled to Humboldt County with adjustments for climate zone, population and total county energy consumption. Details of the energy efficiency analysis are described in Appendix C.

2.3.5 Smart Grid and Demand Response

Smart grid technologies can provide for two-way communication over the electrical grid, thereby allowing for control of appliances at customers' homes and businesses. Smart grid technology will be critical to allow intermittent renewable energy resources to charge electric vehicles, generate hydrogen fuel for vehicles, and charge heat pump thermal storage systems. As such, smart grid technology can play a significant role in the context of Humboldt County's renewable energy future. As of March 2012, PG&E has installed almost 98,000 electric and gas smart meters in Humboldt County, which accounts for 89 percent of eligible meters (PG&E, 2012).

By 2030 the smart grid will likely provide mechanisms to induce consumers (residential, business, and industrial) to curtail or shift electricity demand at critical times based on price signals. There are numerous programs being studied and pilot tested currently, with critical peak pricing being the framework in California (Goldman, Hopper, Bharvikar, Neena, & Cappers, 2007). Table 2 contains a summary of demand response studies for California. Based on the range of estimates from those studies and with an assumption that Humboldt County is typical in the California context, it is reasonable to expect up to 10percent to 15 percent of peak electricity demand can be curtailed or shifted to a later time with appropriate program design and supporting technology. A maximum of 10 percent load curtailment and 6 percent load shifting were assumed in the REPOP Model.

Table 1: Sectors and End-Uses Included in 2008 Itron Energy Savings Potential Analysis

End-Use	Description
Residential Electric	
HVAC	High efficiency central and room air conditioners, heat pumps, whole house fans, windows, infiltration control and attic and wall insulation
Lighting	Compact fluorescent lamps and hardwired fixtures, LED exit signs, occupancy sensors, photocells, T8 linear fluorescents, and torchieres
Water Heating	Water heaters, low-flow showerheads, faucet aerators, high efficiency clothes washers, dishwashers, and pipe wrap
Miscellaneous	One-and two speed pool pumps, high efficiency refrigerators and refrigerator and freezer recycling
Residential Gas	
HVAC	High efficiency gas furnace, attic and window insulation, infiltration control, and duct repair
Water Heating	Water heaters, low-flow showerheads, faucet aerators, pipe wrap, clothes washers, and dishwashers
Commercial Electric	
HVAC	High efficiency air conditioning, chillers, chiller tune-up, motors, and DX tune-up
Lighting	Compact and efficient linear fluorescent lamps and hardwired fixtures, HIDs and metal halides, LED exist signs, time clocks, occupancy sensors, and photocells
Refrigeration	Controls, infiltration barriers, compressors, fan motors, and night covers
Food	Holding cabinet, steamer, high efficiency ovens
Miscellaneous	Copy machines, high efficiency computers, and vending machine controls.
Commercial Gas	
HVAC	Boilers and high efficiency furnaces
Food	High efficiency steamers, ovens and fryers
Water Heating	Water heaters, boilers, circulation pump time clocks, and clothes washers
Miscellaneous	High efficiency water heating boilers, water heaters, and pool heaters

Source: Itron (2008)

Table 2: Demand Response Studies Focused on California

Reference	Study Type	Sector	Notes	Percentage reduction (%)
Herter and Wayland (2010)	Pilot study	Residential	483 California households in 2004; critical peak pricing	5.1% (avg.) 1.9-10% depending on climate and housing type.
Goldman et al (2007)	Mixed	Commercial / Industrial (C&I)	Economic model to estimate C&I demand response in California; multiple mechanisms studied	0-5% depending on customer size and program type.
Brattle Group et al. (2009)	Economic Model	All	Nationwide study with state highlights; multiple mechanisms included in estimates (parallel programs).	6.1% (Business As Usual (BAU)) 6.5% (expanded BAU) 12.6% (achievable) 17.3% (full participation)
Piette et al (2006)	Pilot Study	Commercial	18 facilities with automated demand response.	8% coincident reduction.

Source: SERC staff.

2.3.6 Upgrades to Electrical Transmission System

One alternative for enabling the large-scale development of renewable energy resources in Humboldt County may be to upgrade the capacity of the transmission lines that serve the county, thereby allowing excess renewable power to serve loads in other geographic regions of the state. The current transmission infrastructure has four circuits that connect Humboldt to the greater California grid. These circuits include two 115kV lines from Cottonwood to the east, one 60kV line from Trinity to the east and one 60kV line from Laytonville to the south (PG&E 2005). The combined thermal limit to the export (or import) of power over these circuits is 80 Megavolt-amperes (MVA) to 167MVA. The range of limits is due to a combination of real-time factors such as weather and congestion outside of Humboldt. In addition, the power factor over the system is less than unity, which means that the exportable real power is less than the capacity of the lines. In addition, there must be redundancies in the system to ensure reliable operation of the Humboldt area grid. Accurately estimating all of these factors at the hourly time resolution of the energy balance model was beyond the scope of this study. The authors therefore make the conservative assumption that there is currently a 60MW limit to the real power that can be exported or imported from/to Humboldt County during any hour of the year.

Consultation with PG&E staff has confirmed that a normal operating capacity of 60-70 MW is reasonable. The authors considered an expansion of the capacity of the transmission system serving Humboldt County of up to 200 MW in the REPOP Model.

2.3.7 Distributed Generation and Combined Heat and Power

Distributed generation has been defined by the California Energy Commission as electricity production of a capacity of 20 MW or less that is on-site or close to a load center and is interconnected to the utility distribution system (California Energy Commission 2007). Typical distributed generation technologies include photovoltaics, small wind, small biomass, and small combined heat and power (CHP) or small cogeneration. The Humboldt RESCO optimization analysis considered distributed photovoltaics, along with small biomass and small hydro. However, the representative small biomass and small hydro projects considered may not meet the California Energy Commission's definition of distributed generation because they may not be located on-site or close to a load center and may interconnect to a substation at a transmission level voltage (likely 60 kV).

With regard to small, distributed generation that is connected on-site at distribution level voltages, it is not expected that these facilities will contribute a large portion of the Humboldt County electricity supply. For example, while the REPOP model simulations did consider distributed photovoltaic capacity up to 10 MW, it was found not to be economically preferable compared to other available renewable resources. Other distributed generation opportunities that might meet the California Energy Commission's definition include small wind and small biomass facilities, though it is not expected that there will be a large number of opportunities for these technologies to be connected at the distribution level.

Finally, combined heat and power opportunities may play a role. While these opportunities were not examined as part of the RESCO analysis, it is recommended that they be included in the strategic plan and be studied in the future. One key resource for this further study is the Pacific Clean Energy Application Center sponsored by the U.S. Department of Energy[4]. Another key resource is a recent consultant report prepared for the California Energy Commission that quantifies the long-term market penetration potential for combined heat and power (ICF International, Inc., 2010). Prime opportunities for CHP include commercial and industrial applications where substantial thermal energy is required. These include hospitals, jails, colleges, large office buildings, casinos, supermarkets, and commercial and industrial processes. CHP systems are typically sized to meet the heating load.

Regardless of whether the distributed generation opportunities in Humboldt County fit the California Energy Commission's definition and regardless of whether they can meet a large portion of the local electrical demand, the authors feel that distributed generation can still play an important role in Humboldt County's RESCO plan. Small, distributed projects are one key way that local residents and businesses can directly participate in implementing the RESCO vision. This can play an important role in building community support for the goals of the

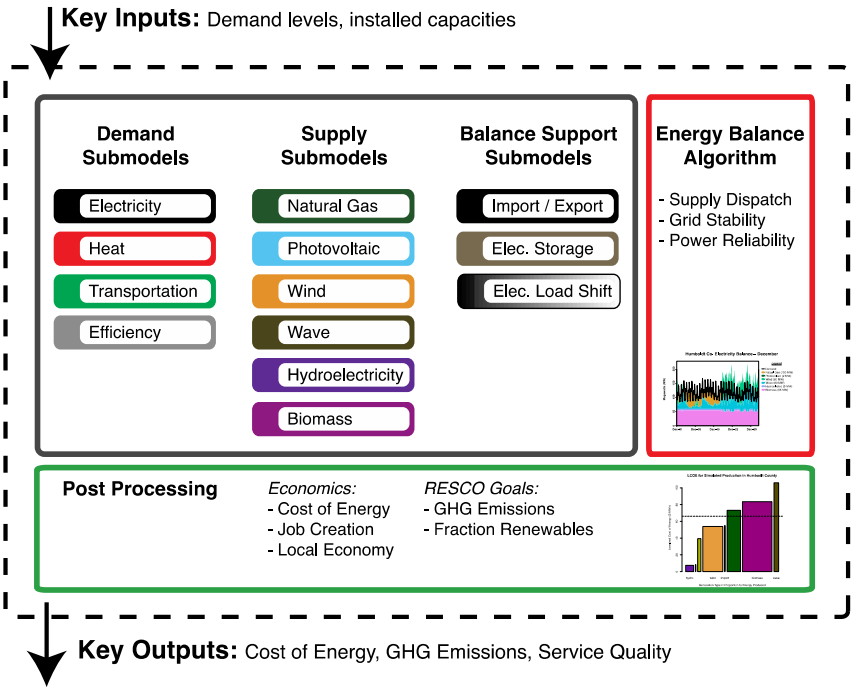
[4] http://www.pacificcleanenergy.org

greater community, and therefore is expected to be a significant part of the Humboldt County RESCO strategic plan.

2.4 Energy Balance Model Methodology

This section describes the Regional Energy Planning Optimization (REPOP) Model. The REPOP model includes an energy balance model and an optimization algorithm that wraps around the energy balance model. See Section 2.4.11 for a description of the optimization algorithm. The energy balance model is made up of a combination of submodels that characterize supply and demand for energy, an algorithm that dispatches supply to meet demand, and post processing algorithms that serve to summarize a model run. Figure 8 depicts how these algorithms work together to model energy production and consumption. A portfolio, or combination, of generation capacities and demand levels is defined as the input to the model. Outputs from the model summarize the resulting energy costs, greenhouse gas emissions, economic impacts and service quality associated with the supply and demand portfolio used to serve Humboldt County's energy needs for one year. Each of the submodels is briefly described below. Details on the individual submodels and the team's background research that informed their creation are included in Appendix D and in other sections that describe the technologies in question.

Figure 8: Regional Energy Planning Optimization Model



Source: SERC staff.

2.4.1 Supply Modeling

To the extent that data allow, the energy balance model simulates the availability of electricity from the following sources on an hourly time scale: natural gas, biomass, wind, wave, hydropower, solar photovoltaic (PV) and import from outside the county. Each source is assigned a maximum power output capacity along with a distribution of availability for each hour of the year (that is, at a given hour some percentage of the total capacity is available).

For the intermittent resources (wind, wave, solar, and hydro), the hourly availability is based on observed or derived data that are representative of the resource in the geographic region where it is currently or is likely to be developed (for example, wind resource near Cape Mendocino, wave power off of Humboldt Bay). For the natural gas power plant, the full net capacity of the plant is assumed to be available. For the biomass power plants, the hourly availability is based on a time series model designed to reproduce key operational characteristics observed at a local power plant. For a detailed description of each of the supply submodels, including a listing of technical and economic assumptions, see Appendix D.1.

2.4.2 Demand Modeling

Humboldt County residents' demand for energy falls generally in three categories, classified by the general end-use: electricity-driven services, heat, and transportation. The demand submodels in the energy balance model consider the three end-use categories separately with a goal of developing estimates for hourly demand for electricity and daily estimates for liquid and gaseous fuels.

Of all the fuels, electricity is the most flexible; people in Humboldt County use electricity to saw logs, communicate using modern media, light their homes, and for a myriad of other purposes. With enabling technologies electricity can be used to meet demand in the other end-use categories. Fuel switching from liquid or gaseous fuels to electricity for heating and transportation is a key phenomenon the model is designed to study. Table 3 summarizes the type of fuels considered in each end-use category. Note that electricity shows up in each.

Table 3: End-Use Energy Categories and Fuel Types Included in Demand Estimates

End-Use	**Energy and Fuel Types**				
Electricity Services	Electricity				
Heat	Electricity	Natural Gas	Propane (LPG)	Kerosene	Wood
Transportation	Electricity	Gasoline	Diesel	Biofuels	

Source: SERC staff.

2.4.2.1 Demand Submodel Framework

The following submodels were used to develop estimates of demand for energy in Humboldt County.

Heating

The monthly demand for heat (for space heat, hot water, and cooking) is estimated for each end-use sector based on natural gas billing data, information on natural gas market share by sector, and estimates of the baseline efficiency of existing heating equipment and appliances. The monthly heat demand estimates are parsed into the hours of each month using typical load profiles for non-weather related end-uses (hot water and cooking). For space heating, a weather-sensitive end-use, the hourly parsing was based on results from a set of DOE-2[5] energy models that represent typical building types in Humboldt County. The hourly demands for heat, weather-related or not, are then satisfied using a fleet of equipment and appliances. The fleet characteristics reflect the existing equipment stock as well as improvements associated with energy efficiency upgrades. By varying the model constraints it is assumed that from 0 to 38 percent of the space heating and hot water heat demand currently being met with natural gas furnaces can be met with electric heat pumps. The output from the heating submodel is an hourly demand for electricity and monthly demands for other heating fuels. The implementation of efficiency measures is accounted for as described below.

Transportation

The overall annual demand for transportation fuels and electricity for charging vehicles is based on methods presented in Appendix A. Baseline gasoline and diesel demand is based on annual vehicle miles traveled and fuel consumption data. Electricity demand is parsed into an hourly demand profile using a mix of typical daily load profiles from NREL (Parks, Denholm & Markel, 2007) with 60 percent lower demand on the weekends than the weekdays. The output from the transportation submodel is hourly demand for electricity and monthly demands for other fuels. Only automobiles and light duty trucks (under 3000 lbs.) are included in the analysis.

Energy Efficiency Programs

The overall impact from efficiency programs is calculated in terms of avoided electricity and natural gas demand. Supply curves for efficiency improvements are based on the base, mid, and full incentive scenarios as described in Appendix C. The net impact of electricity and gas energy efficiency measures is defined in terms of the fraction of the maximum efficiency potential that is captured. Those impacts are then distributed into the hours of the year proportional to the hourly load (that is, greater impact at peak times, less impact at off-peak).

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[5] DOE-2 is a widely used and accepted freeware building energy analysis program that can predict energy use for all types of buildings. See www.doe2.com.

Electricity

The demand for electricity is estimated by modifying the current-day electricity demand on an hourly basis. First, the existing electric heat demand (that is, mainly resistive heat) is subtracted so the data represent non-heat electricity demand. The demand is further reduced according to the level of efficiency program implementation. Finally, the additional electric demand from electric vehicles and heating systems is added to arrive at a corrected electricity demand dataset. The corrected dataset is then linearly modified to reflect population growth (described in Appendix D.3.1).

2.4.3 Stochastic Analysis

Electricity demand, as well as electricity supply from intermittent renewable resources like wind, wave and solar all exhibit some randomness. At any given point in time there might be excessive peak demands that are coincident with severe low points in the availability of intermittent renewables. Analyzing the overall reliability of the electricity grid based upon a small number of simulation years can lead to biased results. In order to avoid this potential bias and capture the probability of these rare events, the model is designed to be stochastic. For some submodels (such as electricity demand or wind), time series are randomly drawn from a pool of source data to simulate a given year. For the biomass submodel, a time series model is developed that synthesizes hourly availability for the plants. The full details of these stochastic models are described in Appendix D.1.

2.4.4 Demand-Side Management

The model includes a provision for electricity demand curtailment and shifting as a demand response when demand outstrips the available supply. For three types of demand (typical electricity, electric heat, and electric vehicle charging) there are three parameters that determine the degree and flexibility of demand response: curtailment fraction, shift fraction, and shift half-life. The curtailment fraction is the absolute fraction of peak demand that can be shed. The shift fraction is the fraction that can be shifted to a later time, and the half-life determines the decay rate of the shifted energy (that is, how much of the pent-up demand dissipates over time). For transportation demand, there is a provision to replace any curtailed electricity with gasoline while accounting for the gasoline engine efficiency of PHEVs. Based on the background research presented in Section 2.3.5 above, the parameters shown in Table 4 were used in the model.

Table 4: Demand-Side Management Factors

Sector	Curtailment Fraction	Shift Fraction	Shift Half-life
Typical electricity	10%	2%	12 hours
Electric heat	10%	2%	6 hours
Electric vehicles	6%	6%	10 hours

Source: SERC staff.

2.4.5 Long-Term Demand Forecasting

Forecasts of future energy demand in the year 2030 are entirely based on population growth projections. Appendix D.3.1 presents a detailed discussion of the population growth model and assumptions.

2.4.6 Energy Balancing

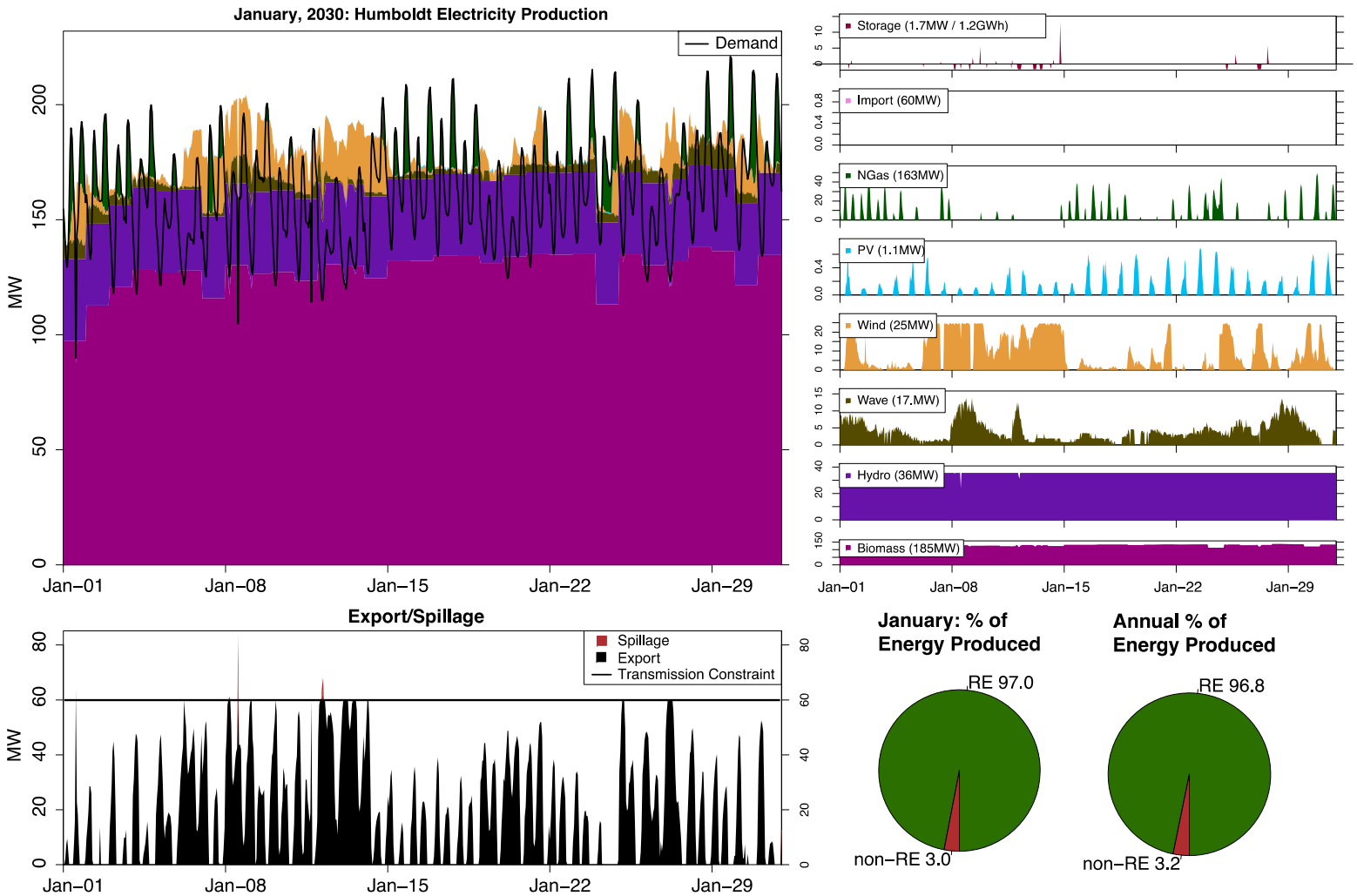
The authors developed an hourly model to balance the local supply and demand for electricity. Resources are dispatched based on an assigned priority, where renewable resources are utilized first, followed by the fossil fuel power plant and then import from outside the County. A reserve requirement must be met every hour of the year (section 2.4.7 provides a description of reserve capacity). Excess power from renewable generators can be exported up to the capacity limit of the transmission system.

The model employs an algorithm that steps through each hour of the year and dispatches resources to meet the electricity demand. A simplified formulation of the energy balance algorithm follows:

1. Always meet the reserve requirement.
2. Meet demand with available supply of priority.
3. Export excess power from renewable generators.

A full description of the energy balance algorithm is provided in Appendix D.4. Figure 9 shows the results of the energy balance algorithm for the month of January in an example simulation.

Figure 9: Example Results From Energy Balance Algorithm



Top left: Model demand (black line) and supply from various generators (color shaded regions) for a simulated month. Top right: Electricity supply by individual generator, colors in these plots match colors in top left panel. Bottom left: Electricity exports and energy spillage (available power that is not consumed or exported due to insufficient demand/transmission capacity). Bottom right: Fraction of renewable energy (RE) and non-renewable energy (non-RE) for the month and the entire year of the example simulation.

Source: SERC Staff

2.4.7 Reserve Capacity Requirements

Reserve capacity on the electricity grid is necessary to accommodate unforeseen fluctuations in demand as well as supply. In order to adequately evaluate renewable energy development scenarios, it is important that reserve requirements are accounted for. Reserve capacity is associated with uncertainty. If grid operators know exactly what the demand will be in the future, no reserve is necessary. In reality, operators can only estimate or forecast the future demand and available intermittent renewable power capacity, and therefore need enough reserve to cover any error in their forecasts.

The authors conducted an analysis of the uncertainty associated with hour-ahead forecasts of demand, wind power production, and wave power production to model the reserve capacity needed in any hour of the year,. A persistence forecasting method was used where the assumed demand or intermittent power production in the next hour was equal to that in the current hour. In reality, grid operators can employ a multitude of forecasting techniques that produce results far more accurate than with persistence forecasting. The persistence forecast method was employed as a highly conservative measure of the uncertainty associated with demand and production. A more complete description of the methodology used for estimating hourly reserve capacity is provided in Appendix D.2.3.

2.4.8 Energy Storage

One alternative to increasing transmission capacity in and out of the county is to develop local energy storage capacity. Like increased transmission, local storage capacity introduces flexibility into the electric grid. In reality, a storage facility would likely operate to maximize revenue. However, the authors lack the detailed price and contracting data necessary to accurately model purchasing costs and revenues from a storage facility. Therefore, the facility is assumed to operate in a manner intended to achieve the overall goals of this study, namely, serving local electricity demand with local renewable energy. To this end, the overall operational strategy is aimed at enhancing system flexibility for the Humboldt County grid.

The energy storage submodel requires specification of the following energy storage system parameters: nameplate power capacity (MW), energy capacity (MWh), round trip efficiency (percent), decay rate (percent/hr), and percent usable capacity (percent). These parameters can be defined for any storage technology (for example batteries, compressed air, pumped hydro). Appendix D.2.2presents a description of how these parameters are used in the storage model.

During model development, the authors experimented with various control strategies for charging and discharging storage. Ultimately, a strategy was employed that allows the storage facility to act as a mechanism for both absorbing excess renewable energy and filling supply deficits when demand outstrips generation capacity. The storage operation strategy maintains a target state of charge (in the model the target is 50 percent) by using the following decision rules:

- Discharge to help meet demand; the priority of storage as a generator is set below that of all other generators including import.

- If not discharging to help meet demand, discharge if the state of charge of the system is above the target state of charge and if doing so will displace natural gas and/or import. In other words, the storage facility does not export power and therefore will not discharge if there is enough renewable energy to satisfy demand.
- If not discharging, charge anytime there is available capacity (that is the capacity not serving load, exporting, or in reserve) and the state of charge is below the target.

The effect of these decision rules is the facility moves toward the target state of charge when possible and remains there in standby mode. Since the facility has spare charging and discharging capacity, it can respond to either type of contingency when needed.

2.4.9 Operational Constraints

The electric grid is a highly dynamic and complex machine that must be operated and maintained to rigorous standards to provide the high degree of safety and reliability demanded by end-users. In addition, power exchange on the electric grid is the physical manifestation of a dynamic and complex economic market containing myriad agents with various roles and interests at stake. A truly accurate model of the electric grid in Humboldt County would need to suitably capture most of the detail associated with the physical and economic forces at play in the system. Unfortunately, such a sophisticated modeling exercise is beyond the scope of this study. The model therefore contains the following simplifying assumptions with respect to operational and contractual constraints on the electric grid.

- All generators can be curtailed any hour of the year by any amount (with biomass power as an exception, see next bullet).
- Biomass power plants can only be curtailed by 10 percent of the available capacity in a given hour. In part, this constraint reflects the contractual obligation that some local biomass power plants have to meet or exceed an 80 percent capacity factor for certain qualifying months of the year (Marino, 2010). Additionally, this requirement ensures biomass generation will be online every hour of the year, which is used as partial justification for ignoring issues with transient stability, as discussed in the following bullet..
- The impact of asynchronous generators on transient stability is ignored in this study. This choice is based on the fact that firming generators (biomass and natural gas power plants) are always online in the model simulations. In a majority of this study's results over 50 percent of instantaneous generation is always from firming sources, and in the worst scenario, firming sources account for at least 18 percent of generation. Based on a literature review of the impact of a high penetration of wind on electric power systems (NREL 2008, EWEA 2005), the authors feel confident that these penetrations of non-firming resources are technically achievable, though regulatory and economic challenges may need to be overcome.

- Ramping capabilities of load following generators (natural gas, biomass, and hydropower) are assumed sufficient to follow the combined load and intermittent supply fluctuations from hour to hour (and within the hour).

2.4.10 Post Processing

When the energy balance model completes a one-year simulation of the Humboldt area energy supply and demand, the result is an account of the energy dispatched to meet electricity demand for every hour of the year along with an accounting of transportation and heating fuels consumed. These results are post processed to quantify the technical, economic, and environmental implications of the simulated portfolio. The following sections summarize these calculations and their associated assumptions and justifications.

2.4.10.1 Cost Accounting

A proper evaluation of any energy generation portfolio must include an estimate of the associated costs. For a detailed description of the assumptions and sources used in the lifecycle cost analysis, Schatz Energy Research Center(SERC), 2011. The following description explains how a simplified lifecycle cost analysis is conducted at the conclusion of each run of the energy balance model. The objective of this calculation is to summarize all of the cost implications of a given scenario into a single number that makes it easy to compare portfolios against each other.

To encapsulate the total cost of servicing the energy demand for Humboldt County, the annualized life cycle cost for each technology is calculated individually and then summed together. The annualized life cycle cost is the present value of the project life cycle cost divided by the project lifetime. Dividing by the lifetime normalizes the cost of each technology to a single year allowing all of the technologies and their varied lifetimes to be combined. The following formula is used to estimate the annualized cost of each technology:

$$C_{annual} = \frac{C_{overnight} + \sum_{t=0}^{n-1}\left[\frac{C_{fixed}+C_{variable}}{(1+d)^t}\right]}{n}$$

Where C_{annual}, $C_{overnight}$, C_{fixed}, and $C_{variable}$ are respectively the annualized cost, up front capital cost, annual fixed costs, and annual variable costs of a particular technology, n is the lifetime of the project in years, and d is the discount rate. All costs are in present value terms. Values for the overnight, fixed, and variable costs used for each technology are tabulated in Appendix D.6. Finally, the following list highlights some of the key assumptions made in the cost accounting:

- All cost data are based on present-day (2010) estimates, no technology learning curves are assumed.
- Costs of existing generation capacity are included in the supply estimates.
- Transportation costs include vehicle costs (both conventional and electric vehicles) in addition to fuel and maintenance costs.

- Heating sector costs include the capital cost of installing heat pumps but neglect the cost of existing infrastructure.
- All fuel costs are based on a retail rate.

2.4.10.2 Greenhouse Gas Accounting

In post processing, GHG emissions are estimated for all uses of energy simulated in the model. Table 5 lists the conversion factors used in this analysis along with data sources. The emission calculations are accomplished by multiplying the appropriate emissions factor by the amount of energy consumed for each technology.

Table 5: Greenhouse Gas Emissions Factors Used in the Model

Fuel Type / Generator	Factor (units)	Data Source
Gasoline	97.8 (gCO_2e/MJ)	Well to wheels emission factor from CARB (2009)
Wood (for heating)	0 (gCO_2e/MJ)	SERC staff assumption
LPG	63.7 (gCO_2e/MJ)	Emissions factors from IPCC: http://www.ipcc-nggip.iges.or.jp
Fuel Oil	77.6 (gCO_2e/MJ)	
Natural Gas (for heating)	56.4 (gCO_2e/MJ)	
Electricity Imports into Humboldt	362.7 (gCO_2e/kWh)	E3 GHG Tool for Buildings In California: http://www.ethree.com
PG&E Humboldt Bay Natural Gas Power Plant	450 (gCO_2e/kWh)	Engine manufacturer brochure: http://www.wartsila.com/en/Home
PV, Wind, Wave, Hydropower	0 (gCO_2e/kWh)	SERC staff assumption
Biomass Power	6 (gCO_2e/kWh)	Pellissier (2010); Marino (2010) based on observed usage of natural gas co-firing at Fairhaven power plant.

Source: SERC staff.

Biomass power production from forest-based biomass is considered carbon neutral, with the exception being the use of relatively small amounts of natural gas for co-firing. This is consistent with current California energy and climate policy, as well as policies at the national and international level. The authors acknowledge that this is a complex topic that is currently

being more heavily scrutinized, and that all sources and pathways for biomass energy production should not be considered carbon neutral. It is expected that this policy debate will become better understood and hopefully largely resolved in the near future.

The general consensus regarding where this policy debate is headed seems to be that it depends on how the forest biomass is generated (Bracmort 2011). If standing timber is being removed to fuel power plants, it may not be considered carbon neutral. If forest residues are being used, it more likely can be considered carbon neutral. Current California policy is to view biomass energy production from forest residues (mill waste, slash, thinnings and fuel reduction) as carbon neutral, and the authors expect that this will continue to be the policy well into the future (Pellissier 2010). The current biomass energy plants in Humboldt County and the possible future expansion of biomass energy as outlined in this study fit within this definition of carbon neutral biomass energy derived from forest biomass residue.

2.4.10.3 Fraction of Energy From Renewables

The authors developed two metrics to quantify the fraction of energy supplied by renewables for a particular portfolio. The first metric is referred to as the fraction of electricity met by renewables. This metric considers only the electricity sector and ignores issues of power contracting and ownership. In other words, regardless of who ultimately pays for the electricity, renewable power produced in Humboldt County is assumed to count toward the county's renewable portfolio. In addition, power exports are ignored, so the metric represents just the fraction of local electricity demand met by renewable sources.

The second metric is referred to as the fraction of total primary energy met by renewables. This metric is an attempt to quantify the penetration of renewable energy across all sectors of the energy economy: electricity, transportation, and heating. To formulate such a metric, a series of design choices were made to put these various forms of energy usage on equal footing. The energy balance model produces estimates of demand for fuels in the transportation and heating sectors, not demand for energy service. In order to avoid the complex calculations necessary to estimate the actual energy service demanded in the electricity sector, demand for electricity is instead converted into an estimate of the primary energy necessary to serve the electric load. Therefore, energy in all three sectors is expressed as primary energy and is comparable.

Another complication arises, however, with regards to renewable electricity that is not generated by thermal power plants (PV, wind, hydro, and so forth.). If the primary energy associated with these resources is assumed to be equal to the delivered energy, then their contribution to the overall fraction of renewables is dramatically underweighted compared to thermal sources like biomass. One kWh of biomass energy would have approximately 5.8 times more weight than 1 kWh of wind energy because the dimensionless heat rate for biomass is approximately 5.8. To address this issue, a heat rate is applied to non-thermal renewable generators despite the fact that there is no physical justification for doing so. The authors acknowledge that this choice may be controversial, but the ultimate goal is to fairly characterize the proportion of energy supplied by renewables, regardless of which type of renewable generator is involved.

The heat rate used is a weighted average of the annual local thermal generating grid mix. For example, if natural gas and biomass are the only two thermal generation types in a scenario and they produce 0.25 TWh and 0.75 TWh of power in a year, then the heat rate applied to the non-thermal generators is the weighted average of the natural gas and biomass heat rates in proportion to their annual production.

Once energy in the electricity sector is converted into primary form, then an overall metric is calculated by dividing the sum of primary energy from renewable sources by the overall primary energy across all sectors. For reporting purposes, the metric is also disaggregated by sector (electric, transportation, heating). To do this, the renewable fraction of all primary energy for electricity is first calculated. Then that primary energy (and its associated division between renewable and non-renewable sources) is redistributed back to the transportation and heating sectors in proportion to the fraction of the delivered electricity that served those respective demands. It should be noted here that greenhouse gas emissions are not redistributed in an analogous manner when reported as disaggregated results. The reported emissions from the electricity sector include emissions due to electricity used for transportation and heating.

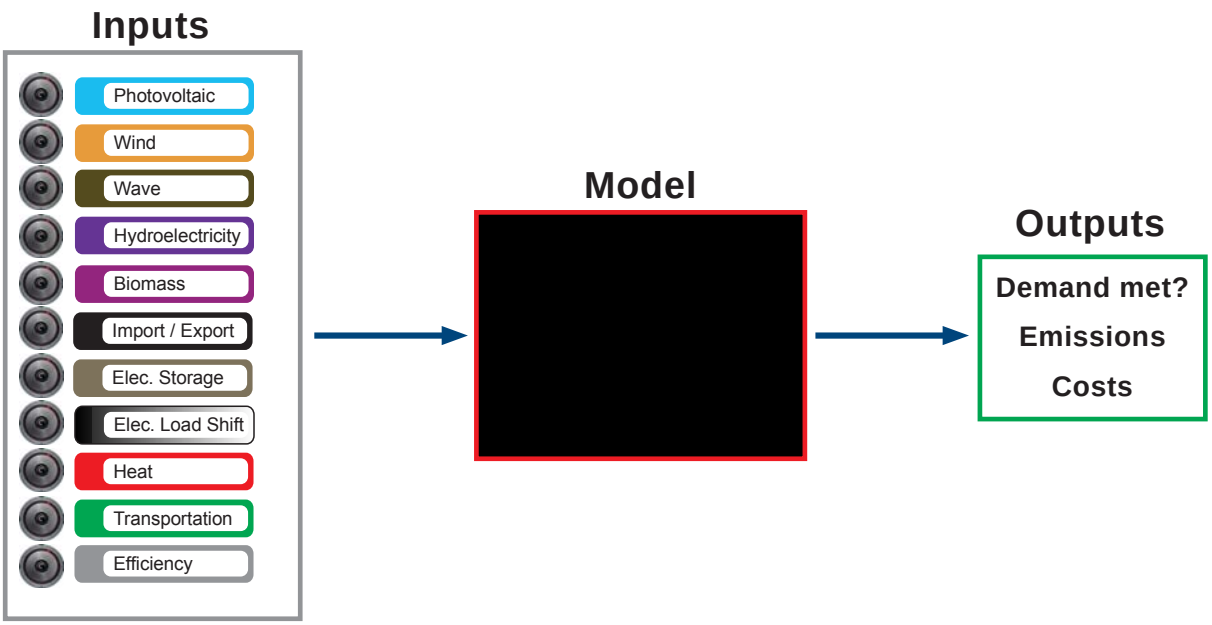
2.4.11 Model Application – Optimization

The overall goal of the Humboldt RESCO technology and resource assessment is to explore the range of supply and demand options available for increasing the use of local renewable energy sources. Ultimately, the authors' results and conclusions should help inform the creation of a strategic plan for moving Humboldt County toward a more sustainable and secure energy future.

With this goal in mind, the research team chose to apply the model in the context of various optimization problems. Optimization can provide answers to specific questions common to long term planning. For example, what portfolio of supply and demand options provides the maximum reduction in greenhouse gas emissions given a certain constraint on the overall cost? This section summarizes the methodological approach used to pose and answer these types of questions while employing the energy balance model.

The energy balance model is capable of simulating the County's energy sector for a year at the hourly timescale. The key inputs to the model include installed energy system capacities (including existing and new capacity), as well as the penetration of demand-side programs and fuel switching technologies (Figure 10). The key outputs are service reliability, the total cost of energy, and the greenhouse gas emissions associated with the scenario.

Figure 10: Black Box Representation of the Energy Balance Model for the Purpose of System Optimization



Source: SERC staff.

The optimization process involves iteratively updating the inputs to the model to achieve a desired outcome in the outputs. The desired outcome is referred to as the objective, and it usually involves minimizing or maximizing the value of an output. Constraints can be placed on the permissible values of both the inputs and the outputs, thereby keeping the range of explored options and outcomes within realistic bounds.

2.4.11.1 Optimization Problem Formulation

Optimization is used to find the portfolio(s) that satisfy various problem formulations, such as:

- Minimize GHG emission without increasing cost above a certain threshold; require that demand is met 99.9 percent of the year, or
- Minimize cost of energy but levy a price per ton of CO2e emitted; require that demand is met 99.9 percent of the year.

Differential Evolution is the optimization algorithm employed in the analysis. Differential Evolution is a metaheuristic global optimization technique, also called a direct search approach, developed by Rainner Storn and Kenneth Price. Appendix D.5 presents a description of the technique and its advantages over other common optimization approaches.

The following descriptions introduce the problem formulations explored through optimization.

Business-as-Usual (BAU)

In this report, the business-as-usual (BAU) scenario represents the energy sector in Humboldt County in the year 2030 assuming that no new generation is developed, no energy efficiency programs are enacted beyond the current base levels, and there is no fuel switching in the heating and transportation sectors. Many of the results in this analysis are reported relative to the business-as-usual scenario (for example, the costs or the emissions associated with a scenario are usually reported as a percentage of business-as-usual).

Greenhouse Gas Minimization (GHG)

The minimization of GHG emissions is the primary problem formulation explored through system optimization. The formulation is subject to the following two constraints: (1) System reliability must be 99.9 percent, (2) Total annualized cost cannot exceed a prescribed level. The result of this optimization represents the portfolio that achieves the greatest emissions reductions at a given cost. It is useful to note that the result of this problem formulation should be identical to the result of the inverse formulation: minimize total cost with an upper constraint on GHG emissions. Indeed, the authors have verified that the optimal portfolio is the same regardless of which problem formulation is used.

To explore the relationship between cost and the emissions associated with optimized portfolios, the optimization is conducted multiple times with varying constraints on cost, including a scenario where cost is not constrained at all. Taken together the results represent points on a Pareto optimality frontier. Because the outputs of interest are costs and emissions, the frontier is a curve in the two-dimensional cost/emissions space. Any point along the curve represents the optimal emissions reductions possible for a given cost.

Cost Minimization

The secondary problem formulation is a cost minimization with a 99.9 percent system reliability constraint. The optimization is solved multiple times, with a successively higher price levied on every ton of CO_2e emitted in the scenario. The solutions to this optimization also form a curve in the same two-dimensional cost/emissions space, though this curve represents the cost and emissions associated with the least cost portfolio at a given price on GHG emissions. This allows us to investigate the implications of carbon pricing policies that may occur at the state and/or federal levels.

2.4.11.2 Constraints on Inputs

There is an important difference between constraints placed on the outputs of the model (cost and emissions) and constraints placed on the inputs themselves (installed capacities, penetration of electrified heating and transport). The problem formulation descriptions in Section 2.4.11.1 focus on output constraints. For all of the optimizations conducted, there are also constraints on the inputs. The constraints are based on author's estimates of the technical

limits to development of each technology in Humboldt County by 2030. Table 6 lists the limits used in the analysis.

Table 6: Decision Variables Used in the Optimizations and Their Corresponding Boundary Constraints

Decision Variable	Lower / Upper Limit of Installed Capacity (includes existing and new capacity)
Wind Capacity (MW)	0 / 250
Wave Capacity (MW)	0 / 100
Biomass Capacity (MW)	61 / 225
Hydropower Capacity (MW)	11 / 38
Solar PV Capacity (MW)	1.1 / 10
Import/Export Transmission Capacity (MW)	60 / 200
Storage Capacity (MW)	0 / 25
Efficiency Program Level (0 = Base, 100 = Full)	0 / 100
Electrified Vehicle Penetration (% of registered vehicles)	0 / 38
Penetration of Heat Pumps (% of residential & commercial natural gas furnaces)	0 / 38
Demand Response (% of max potential or approximately 12% of peak load)	0 / 100

Source: SERC staff.

2.5 Power Flow Analysis – Impacts to the Local Electric Grid

Simulations using the REPOP model identified opportunities for substantial development of renewable energy projects on the Humboldt area electric grid. Before any new generators are added to the grid, however, interconnection studies will need to be performed to identify required transmission and distribution system upgrades. To develop a preliminary assessment of the need for infrastructure upgrades, the Humboldt RESCO study engaged the services of project partner and local investor owned utility Pacific Gas and Electric Company (PG&E).

PG&E's Interconnected Grid Planning group conducted an interconnection feasibility study to evaluate the transmission impacts of a representative scenario for future renewable energy development in Humboldt County. The objectives of the study were to identify:

- Transmission system impacts caused solely by the addition of the proposed renewable energy development;

- System reinforcements necessary to mitigate any adverse impacts of the proposed renewable energy development under various system conditions; and
- Facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility.

The study examined transmission facilities within PG&E's Humboldt and North Coast Areas. The study assumed a projected year 2030 winter peak electric loading condition of 223 MW and included nine proposed new generation facilities in Humboldt County with a total generation output of 253 MW. Table 7 lists the proposed new generation facilities, their locations, and their proposed points of interconnection while Figure 11 shows the geographic dispersion of these facilities.

Table 7: New Generation Sources Considered in Interconnection Feasibility Study

Technology	Max MW	Location Description	Proposed Point of Interconnection
Wind	50	Bear River Ridge	Rio Dell Substation 60 kV Bus
Wind	75	Bear River Ridge	Rio Dell Substation 60 kV Bus
Biomass	40	Samoa	Fairhaven Substation 60 kV Bus
Biomass	15	Willow Creek	Willow Creek Substation 60 kV Bus
Biomass	15	Garberville	Garberville Substation 60 kV Bus
Hydro	8	Maple Creek	Maple Creek Substation 60 kV Bus
Hydro	5	Hoopa Valley	Hoopa Substation 60 kV Bus
Storage – Pumped Hydro	15	Ruth Lake	Low Gap Substation 115 kV Bus
Wave	30	Samoa	Fairhaven Substation 60 kV Bus
Total	**253**		

Source: PG&E, 2011

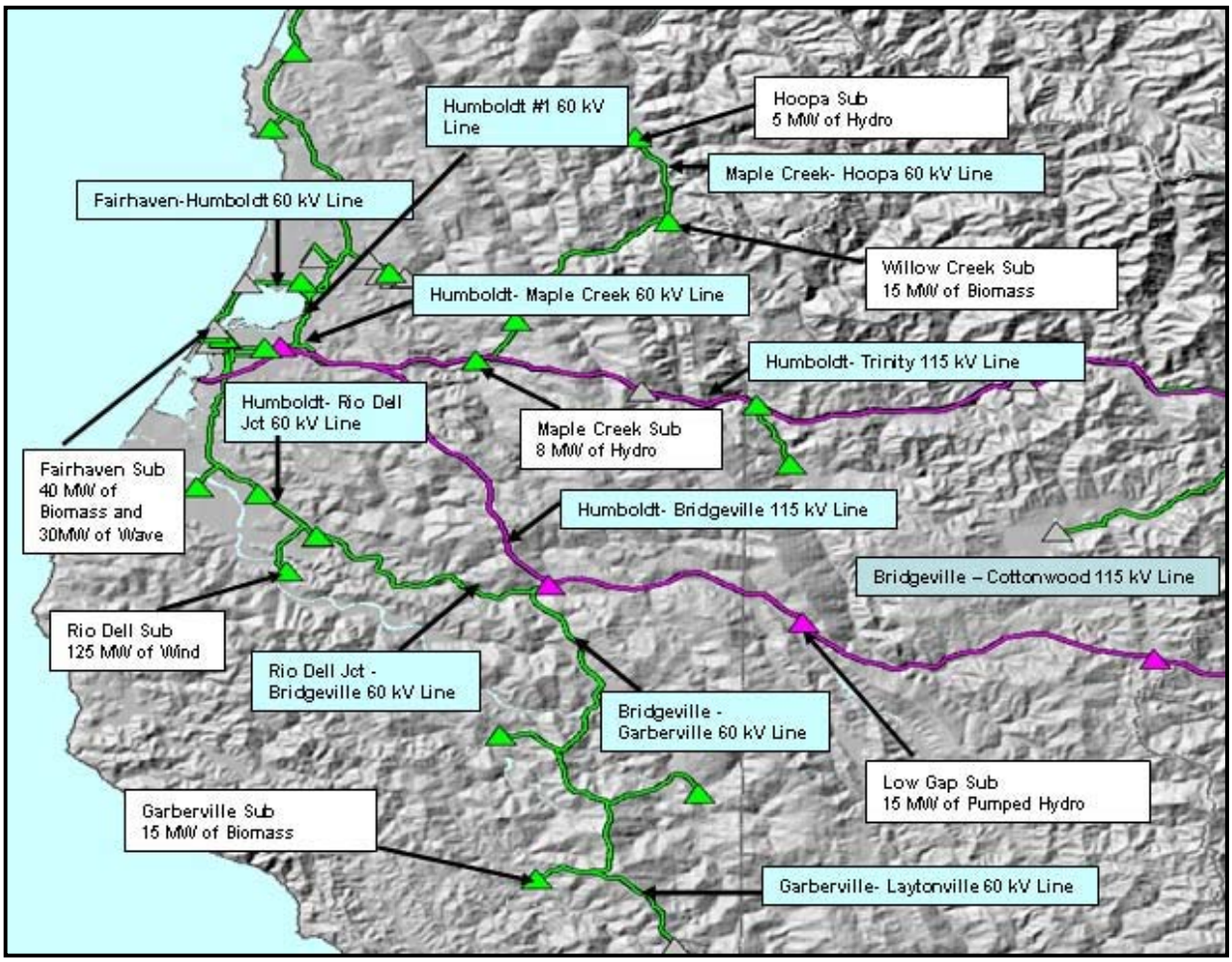
The interconnection study took into account the planned generating facilities in PG&E's service territory that are in the California Independent System Operator (CAISO) Generation Interconnection Queue in the Humboldt and North Coast Areas. In addition, all CAISO approved PG&E transmission projects in the area that will be operational by 2020 were also included.

The power flow analysis was performed to ensure that PG&E's transmission system remains in full compliance with North American Electric Reliability Corporation (NERC) reliability standards. Where a NERC reliability deficiency resulted due to the interconnection of the new generators, PG&E identified the problem and developed appropriate transmission solutions to comply with NERC reliability standards.

Two power flow base cases were used in the analysis. These included a winter peak base case and an off-peak base case, representing extreme loading and extreme generation conditions, respectively. Additional analyses were not possible within the scope of the Humboldt RESCO study. Consequently, it is important to note that this is a preliminary analysis, and the results of this study do not provide any guarantees about the ability of the system to function properly during times, seasons and situations not studied.

The base cases were used to simulate the impact of the proposed renewable energy projects during normal (CAISO Category A) operating conditions as well as during single (CAISO Category B) and selected multiple (CAISO Category C) contingency conditions. In addition, CAISO Category B and C contingencies were analyzed to identify reactive power deficiencies. A full description of the PG&E interconnection study plan is presented in Appendix E.

Figure 11: Location of New Generation Facilities and Interconnection Points



Source: PG&E, 2011.

CHAPTER 3: Outcomes

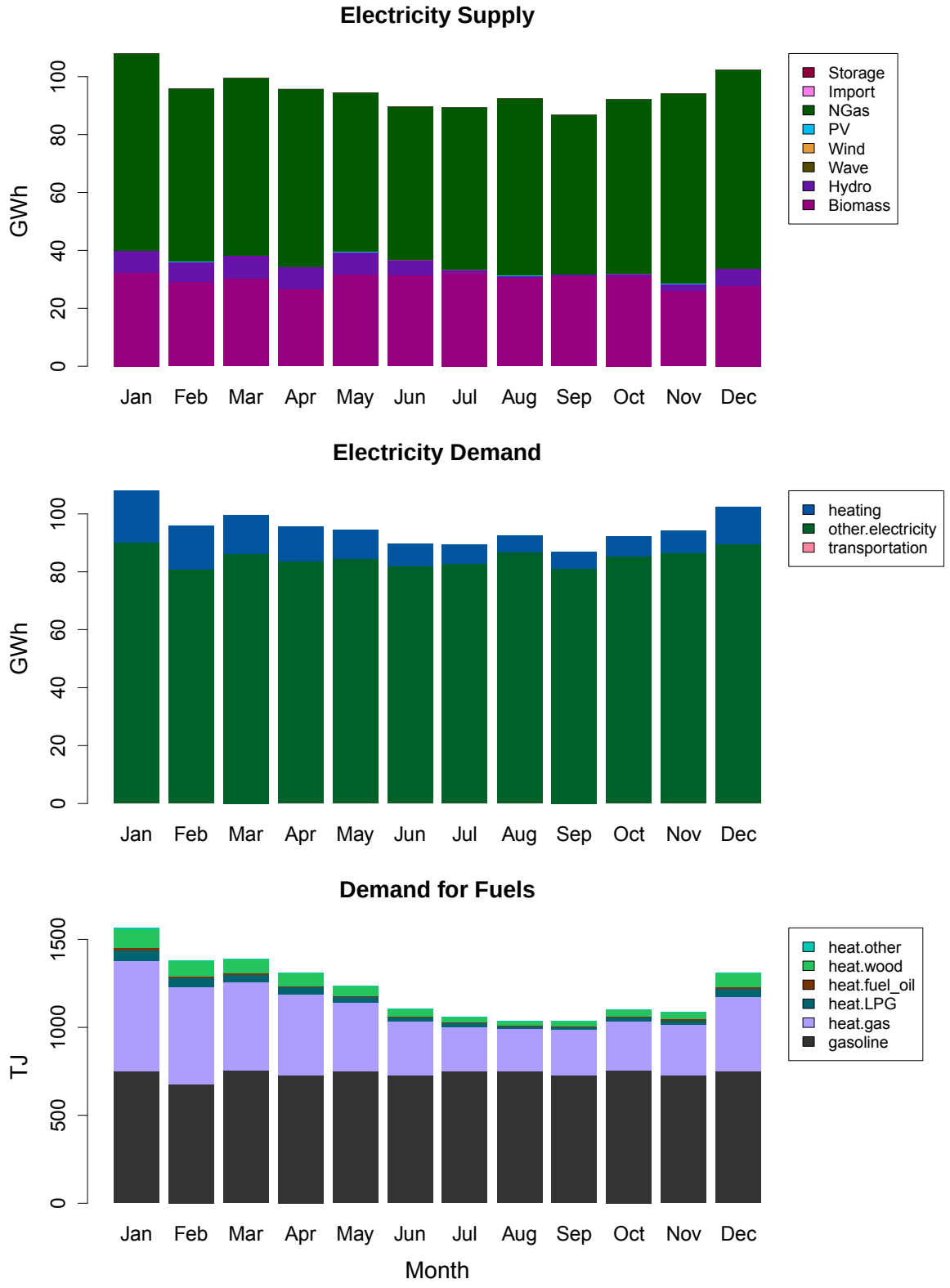
The Humboldt RESCO resource and technology assessment involved the development and use of the Regional Energy Planning Optimization Model. Chapter 3 reports on the results of the REPOP model simulations. A key focus of the work examined the trade-offs between energy costs and greenhouse gas emissions for various renewable energy resource and technology portfolios. In addition, the outcomes of multiple REPOP model sensitivity analyses are reported. Finally, results are presented for the electric grid power flow analysis, the hydrogen fuel cell bus analysis, and the forest-based biofuels analysis.

3.1 Energy Modeling Results

3.1.1 Business-as-Usual

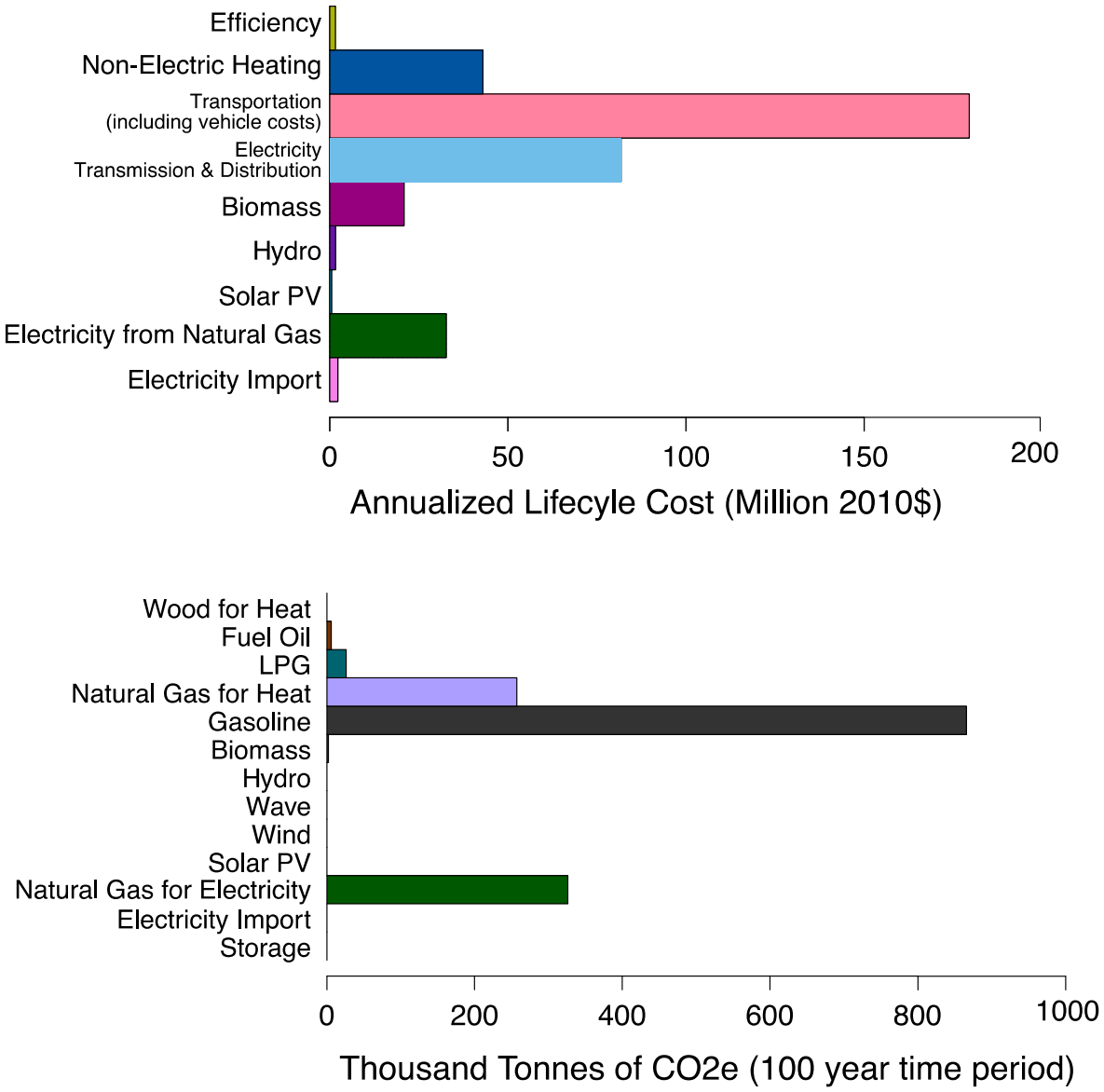
The energy demand and supply results determined by running the energy balance model for the business-as-usual, projected 2030 scenario are presented in Figure 12. The supply of electricity is dominated by natural gas (65 percent) and biomass (30 percent). Likewise, natural gas and gasoline fuels dominate the energy supplied to the heating and transportation sectors, respectively. The total annualized lifecycle cost associated with the business-as-usual scenario is $364M and the total GHG emissions are 1500 kilotonnes CO_2e. Figure 13 reports the costs and emissions associated with business-as-usual disaggregated by technology and fuel type.

Figure 12: Business-as-Usual 2030 Energy Supply and Demand by Month



Source: SERC staff.

Figure 13: Annualized Lifecycle Retail Costs (Top) and Annual Greenhouse Gas Emissions (Bottom) for Business-as-Usual 2030 Humboldt County Energy Needs

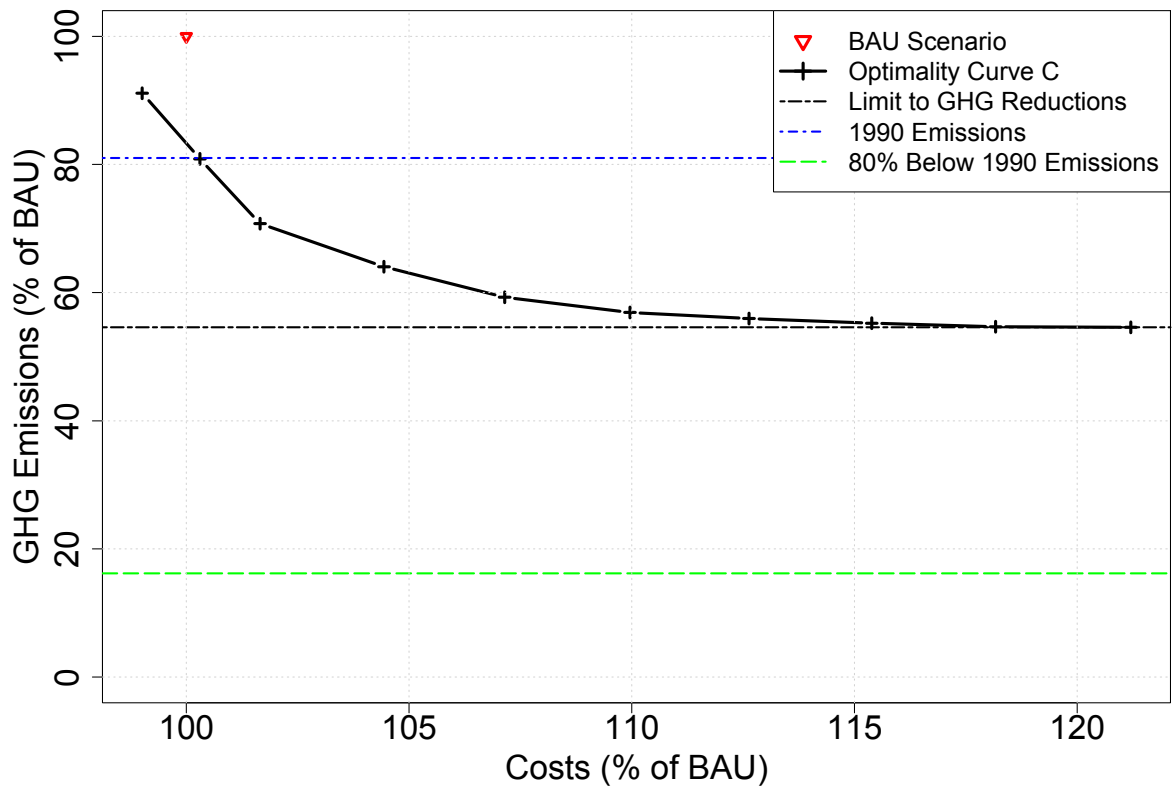


Source: SERC staff.

3.1.2 Greenhouse Gas Minimization

Given the default constraints on the decision variables (Table 6), a series of optimizations were conducted to produce the optimality curve in Figure 14. The curve represents the emissions reductions achievable at a given cost and is referred to as Curve C for reasons explained in Section 3.1.5. The leftmost point on the curve indicates that a 9 percent reduction in greenhouse gas emissions is possible with a 1 percent *decrease* in costs below business-as-usual. As costs increase, more and more emissions reductions are achievable, but with decreasing returns on investment. The dashed black line indicates the limit for reduced emissions. This represents the result of an optimization where emissions were minimized with no cost constraint, and therefore represents the technical limit to reducing emissions given the decision variable constraints in Table 6. The dashed blue line represents 1990 greenhouse gas emission levels, and the dashed green line represents an 80 percent reduction in greenhouse gas emissions below 1990 levels.

Figure 14: Optimality Curve (Curve C) for the Default Emissions Minimization Problem Formulation (Minimize Emissions with Various Cost Ceilings)



BAU stands for business-as-usual.

Source: SERC staff.

The optimal scenarios associated with a subset of the points on Curve C are summarized in Figure 15. For each scenario, the sub-plots show the installed capacities of the generators, the percent penetration of the demand decision variables, and the proportion of electricity demand

met by each generator (with efficiency counting as a generator). The error bars on the bar plots indicate the range of values found by the differential evolution algorithm that equally satisfy the problem formulation. In other words, different variations on a scenario all result in essentially the same overall costs and emissions.

Energy efficiency is maximized in all scenarios, which is consistent with the fact that efficiency measures have a negative lifecycle cost. Hydropower capacity is also maximized in every scenario, indicating that it is the least cost generation technology capable of reducing overall emissions. The capacities of PV and transmission for import/export are minimized in all scenarios, reflecting the fact that their relative costs are extremely high compared to all of the other decision variables.

Generally, as the cost constraint is increased on the optimization, two strategies are simultaneously employed to achieve the lowest GHG emissions possible. These strategies are: (1) increasing the capacity of renewables on the electric grid and (2) fuel switching in the transportation and heating sectors.

However, unexpected results emerge as the cost constraint is progressively relaxed. The capacities of wind and biomass do not exhibit monotonic behavior. Below approximately 102 percent of the business-as-usual cost, wind is favored over biomass in the optimal portfolio. As more money is spent, wind increases in capacity and biomass essentially stays at business-as-usual levels. But at 105 percent of business-as-usual costs, biomass capacity becomes favored over wind. Both technologies are present in each solution, but wind capacity is low (approximately 25MW) and biomass capacity dominates the portfolio. Finally, as the cost constraint continues to relax, wind capacity increases and plays a significant role in the solution along with biomass. This phenomenon is discussed below.

3.1.3 Marginal Cost of Greenhouse Gas Abatement

The tradeoff in dominance of wind versus biomass (described above, Section 3.1.2) can be confirmed and partially explained by estimating the marginal cost of abatement of each technology at every point on the curve. This estimation is made by the following methodology:

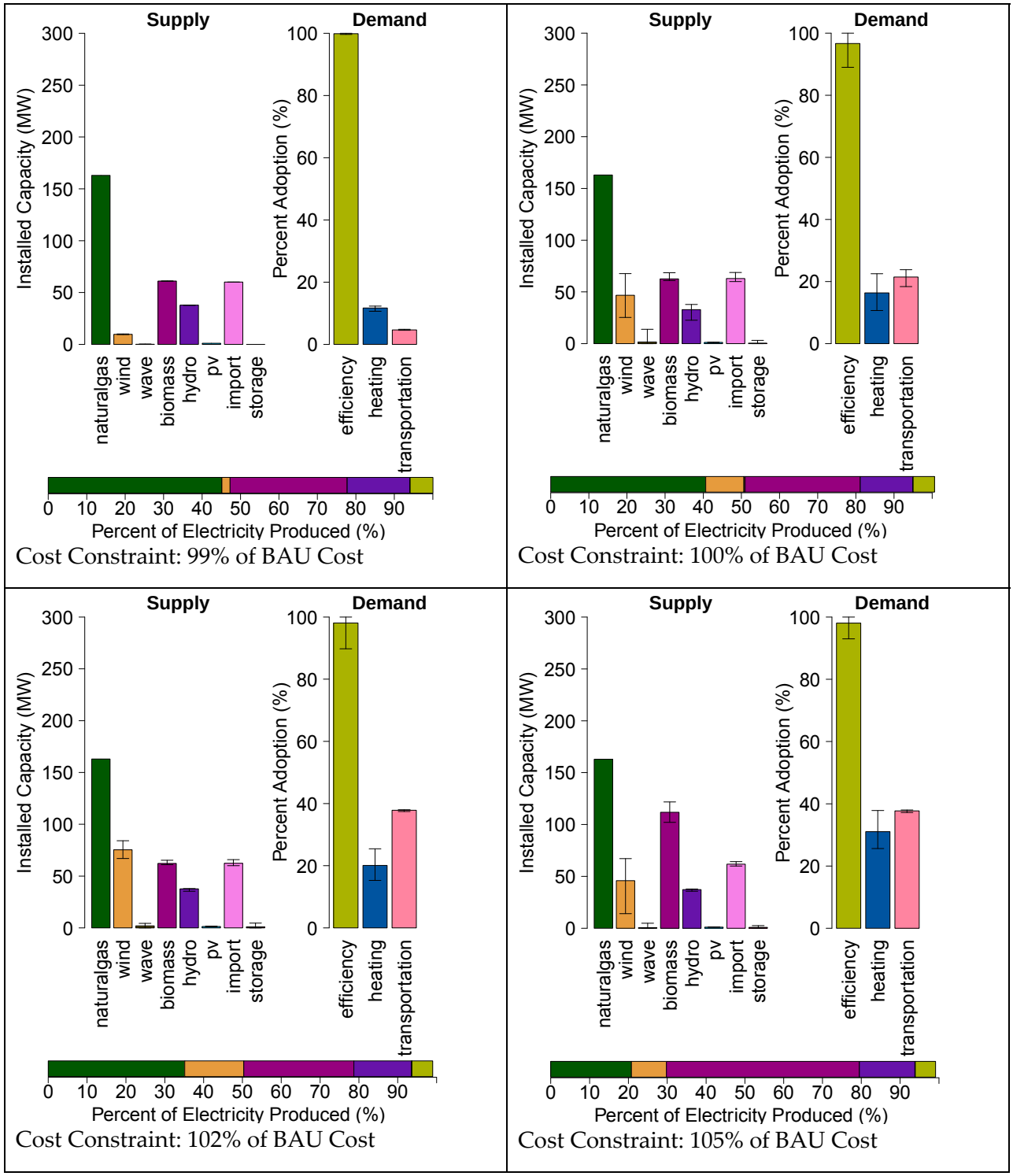
For each point on the curve:

- Run the energy balance model for the optimal portfolio associated with the point.
- Run the simulation four more times, varying the capacity of wind and biomass by +/-10 percent each (while holding all other parameters constant).
- Divide the change in emissions by the change in total cost for both biomass and wind; this is the estimate of the marginal cost of abatement.

The result of this analysis is plotted in Figure 16. Consistent with the results in Figure 15, the marginal cost of abatement of wind is lower at the left end of the optimality curve, but biomass has a lower marginal cost of abatement over the middle region. Finally, there is a region on the right side of the curve where wind again is the lower cost alternative.

While it is illustrative to compare wind and biomass in this manner, it should be stressed that this cannot be considered a full explanation of the unexpected behavior. As the cost constraint is relaxed the impact of all the decision variables, both individually and in combination, ultimately dictates the optimal portfolio.

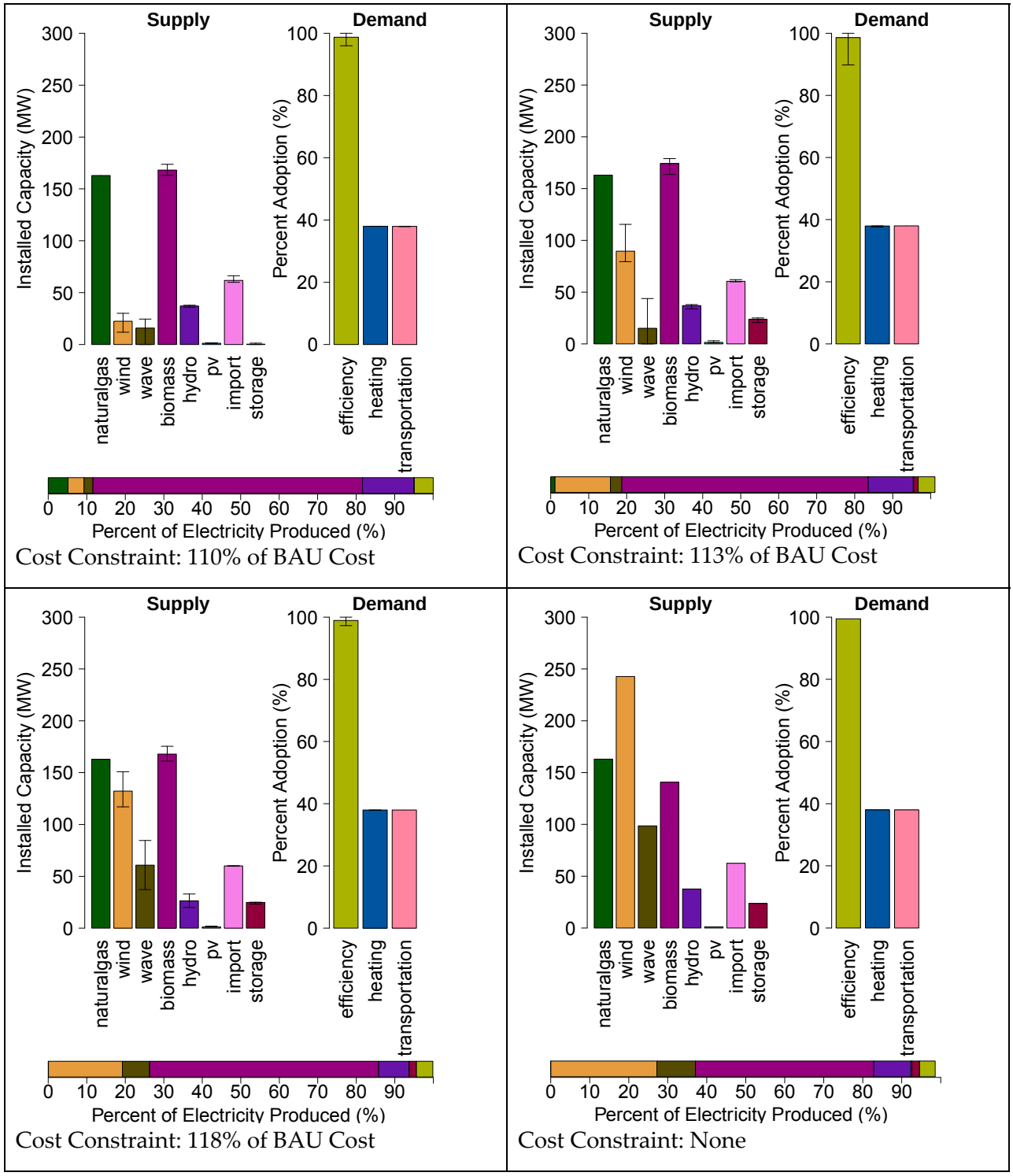
Figure 15: Portfolios From Optimality Curve C



Installed capacities of generators (top left), penetration levels associated with efficiency and load building (top right), and the proportion of the electricity produced by each generator (efficiency is treated as a generator in this context). Colors in the grid mix bar match those in the upper plots and are in the same order from left to right. The error bars associated with the decision variables represent the range of values observed in the converged generation of particles as solved by the differential evolution algorithm. BAU stands for business-as-usual.

Source: SERC staff.

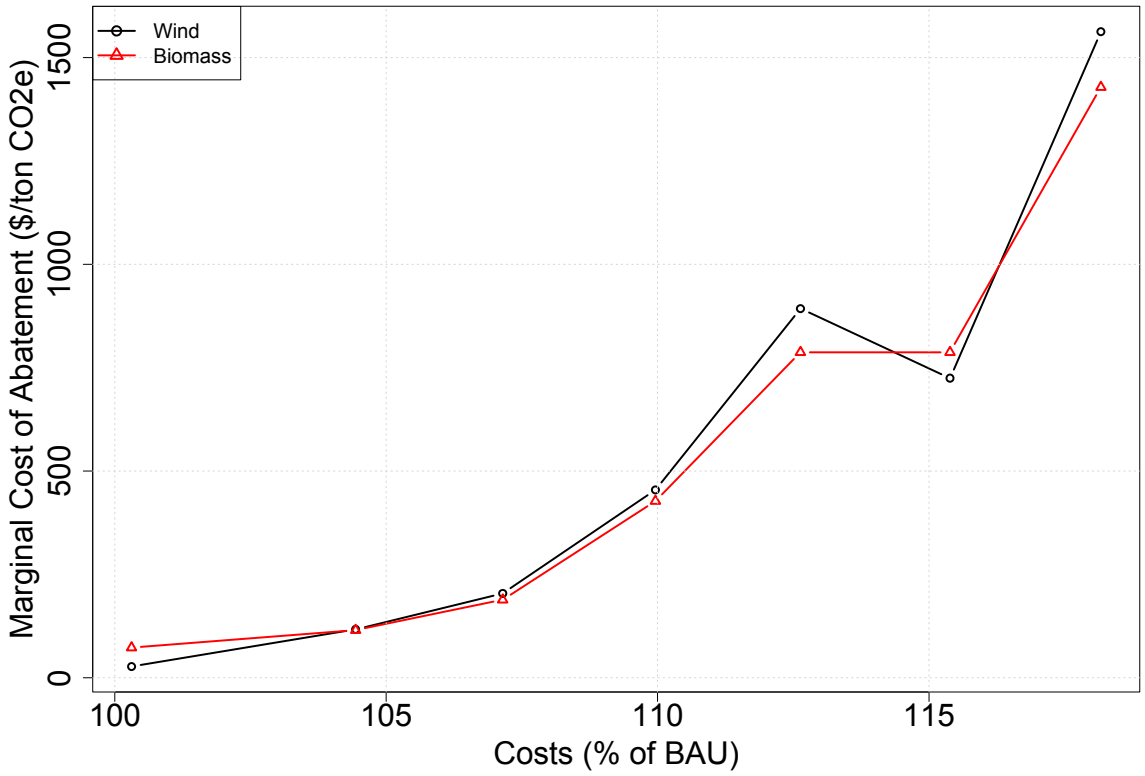
Figure 15 (Continued): Portfolios From Optimality Curve C



Installed capacities of generators (top left), penetration levels associated with efficiency and load building (top right), and the proportion of the electricity produced by each generator (efficiency is treated as a generator in this context). Colors in the grid mix bar match those in the upper plots and are in the same order from left to right. The error bars associated with the decision variables represent the range of values observed in the converged generation of particles as solved by the differential evolution algorithm. BAU stands for business-as-usual.

Source: SERC staff.

Figure 16: Marginal Cost of Greenhouse Gas Abatement for Wind and Biomass at Several Locations Along Optimality Curve C



BAU stands for business-as-usual.

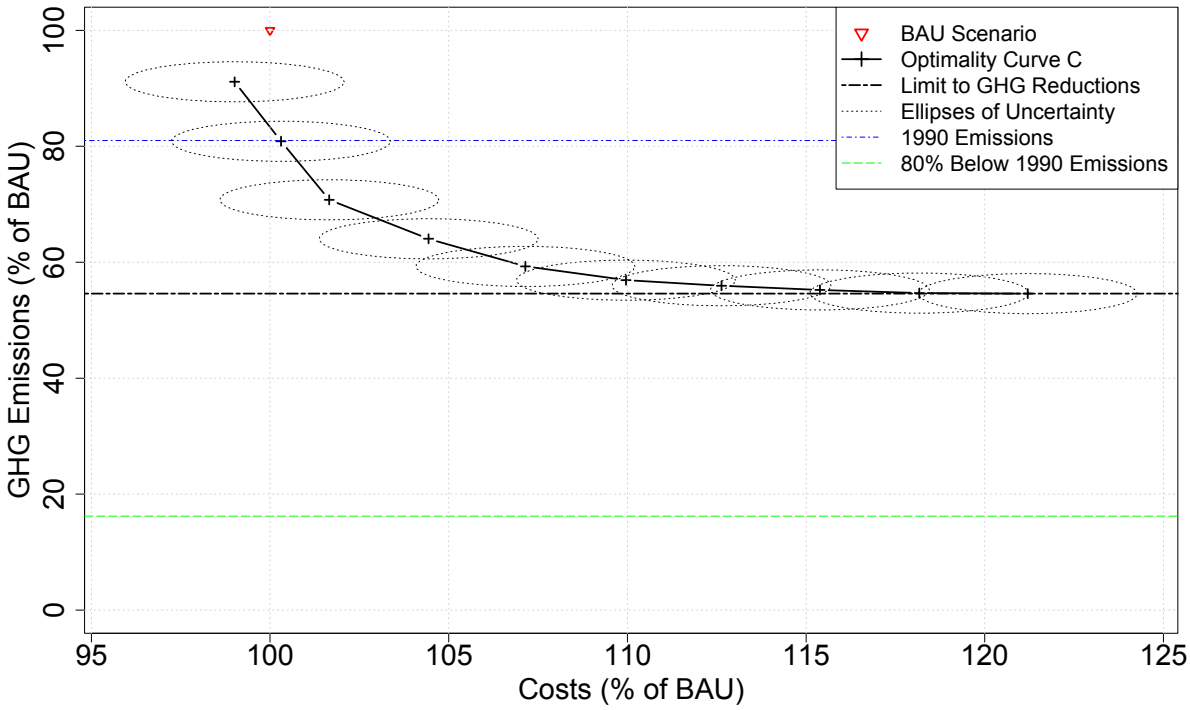
Source: SERC staff.

3.1.4 Error Analysis

To examine the uncertainty associated with these results, the authors conduct a Monte Carlo error analysis. A point on the optimality curve serves as the base scenario for the error analysis. The fourth point from the left was chosen, which roughly corresponds to a 5 percent increase in costs above business-as-usual. The energy balance model is then run 500 times. Before each run, all of the technical and economic parameters in the model (Table 8, 60 parameters in all) are modified by a random amount (no more than +/-10 percent of the original) based on a random draw from a uniform distribution. For discrete inputs (for example what year of source data to use in the wind submodel), one of the possible discrete values is randomly selected with equal probability. The total annualized cost and greenhouse gas emissions are calculated for each model run and the resulting distribution is used to create the ellipses in Figure 17. The axes of the ellipses represent +/- two standard deviations of the resulting values for costs and emissions associated with the 500 model runs.

The distributions from which parameter values are selected in a Monte Carlo error analysis are usually based on prior knowledge about the uncertainty of each parameter. Due to the large number of parameters and the lack of data necessary to confidently characterize their uncertainty, the authors chose to vary all parameters +/- 10 percent. In reality, the uncertainty may be much less than 10 percent for some parameters and somewhat greater for others.

Figure 17: Error Analysis for Optimality Curve C



Ellipses of uncertainty are based on a Monte Carlo error simulation where all model inputs and parameters are varied +/-10 percent; the axes of the ellipses represent +/- two standard deviations of the resulting values for costs and emissions. BAU stands for business-as-usual. Note that axis scales are not equivalent, variability in the cost and emissions dimensions are approximately equal.

Source: SERC staff.

Table 8: Model Parameters Varied in the Monte Carlo Error Analysis

Discount Rate	Import Heat Rate
GHG Emissions Price	Natural Gas Power Plant Heat Rate
Population Growth Rate	Wave Capacity
Efficiency Program Level	Wave Source Data Year
Heat Pump COP	Wind Capacity
Heat Pump Penetration	Wind Source Data Year
PEV Penetration	Wind Source Data Location
Demand Response Capacity	Natural Gas Power Plant Costs (Capital, O&M, Fuel, and Life Time)
Conventional Vehicle Costs (capital, O&M, fuel, and equipment life time)	Biomass Costs (Capital, O&M, Fuel, and Life Time)
PEV Vehicle Costs (capital, O&M, and equipment life time)	Heating Fuel Costs (fuel oil, gas, LPG, wood)
Storage Power Capacity	Heat Pump Costs (Capital, O&M, and Life Time)
Storage Energy Capacity	Hydropower Costs (Capital, O&M, and Life Time)
Storage Target State of Charge	Transmission/Distribution Costs (Capital, O&M, and Life Time)
Biomass Capacity	PV Costs (Capital, O&M, and Life Time)
Biomass Min Turndown Factor	Storage Costs (Capital, O&M, and Life Time)
Biomass Availability Capacity Factor	Wave Costs (Capital, O&M, and Life Time)
Hydropower Capacity	Wind Costs (Capital, O&M, and Life Time)
Import Capacity	

Source: SERC staff.

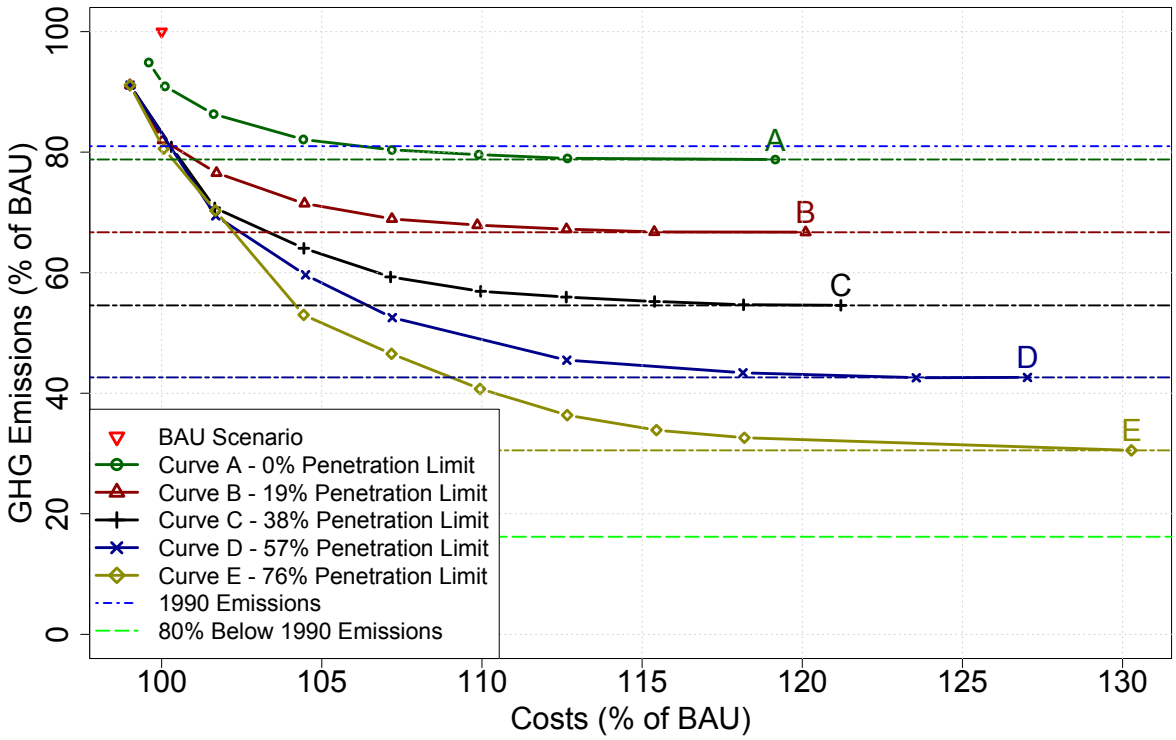
3.1.5 Effect of Changes in Heat Pump and Electric Vehicle Penetrations

The Monte Carlo error analysis only demonstrates the model sensitivity to input parameters. The constraints imposed on the decision variables can have an impact on the results as well. In particular, the limits on the penetration of electric vehicles and heat pumps in the transportation

and heating sectors have a dramatic effect on the emissions reductions that can be realized. To examine this effect, the authors conducted additional optimizations varying the limits on those two decision variables. The resulting optimality curves are plotted in Figure 18. The optimality curves identified as A through E correspond to electric vehicle and heat pump penetration limits of 0 percent through 76 percent, respectively. It is important to note that the authors do not consider curves D and E to be realistically achievable penetration levels for Humboldt County by the year 2030. Nevertheless, those scenarios were included in the analysis to examine the sensitivity of model results to that constraint.

There is a clear linear relationship between the emission reduction limit associated with each curve (represented by the horizontal line at the curve's asymptote) and the limit on electric vehicle and heat pump penetration. For every 5 percentage point increase in the penetration limits, the emission reduction limit decreases by about 3 percentage points.

Figure 18: Optimality Curves With Varying Limits on the Penetration of Electric Vehicles and Heat Pumps



Each curve has a corresponding horizontal line indicating the emissions reduction limit at that penetration level. BAU stands for business-as-usual.

Source: SERC staff.

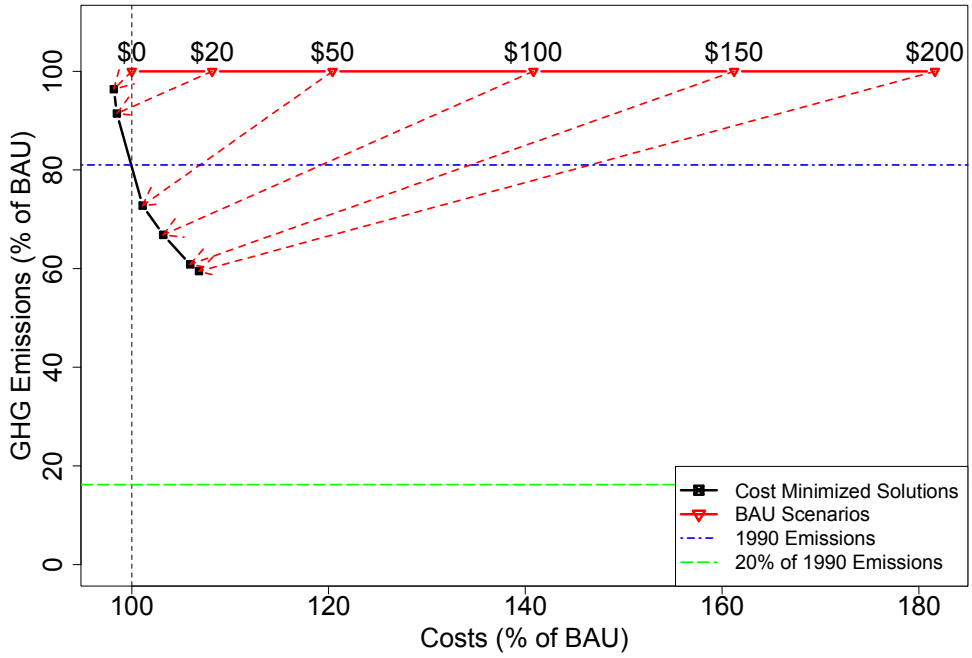
3.1.6 Cost Minimization

Like with the greenhouse gas minimization analysis (section 3.1.2), the default set of decision variable constraints (Table 6) is again used for the cost minimization exercise. The optimization algorithm finds the lowest cost portfolio that serves Humboldt County's energy needs. The

process is repeated for progressively higher prices levied on a ton of CO_2e emitted. Figure 19 presents the results of the optimizations. It is clear from these results that business-as-usual is not the economically optimal scenario, even with no price on carbon. As the price increases, the difference in cost between business-as-usual and the economically optimal scenario increases dramatically. Concurrently, the emissions associated with the economically optimal scenario decrease as carbon intensive technologies are more extensively displaced. The sensitivity of emissions to the price on carbon is very high for the first $50 per ton, but the subsequent reductions quickly decrease as the price increases thereafter.

An unexpected result of this optimization can be seen when the cost minimization curve in Figure 19 is plotted on the same axes as curve C from the emissions minimization analysis (Figure 20). The curves are essentially identical in the overlapping regions. The differences between the curves are well within the region of uncertainty discussed in section 3.1.4. This suggests that the end result is the same whether a cost constrained emissions reduction strategy or a purely economic optimization strategy is pursued in the context of a price on carbon.

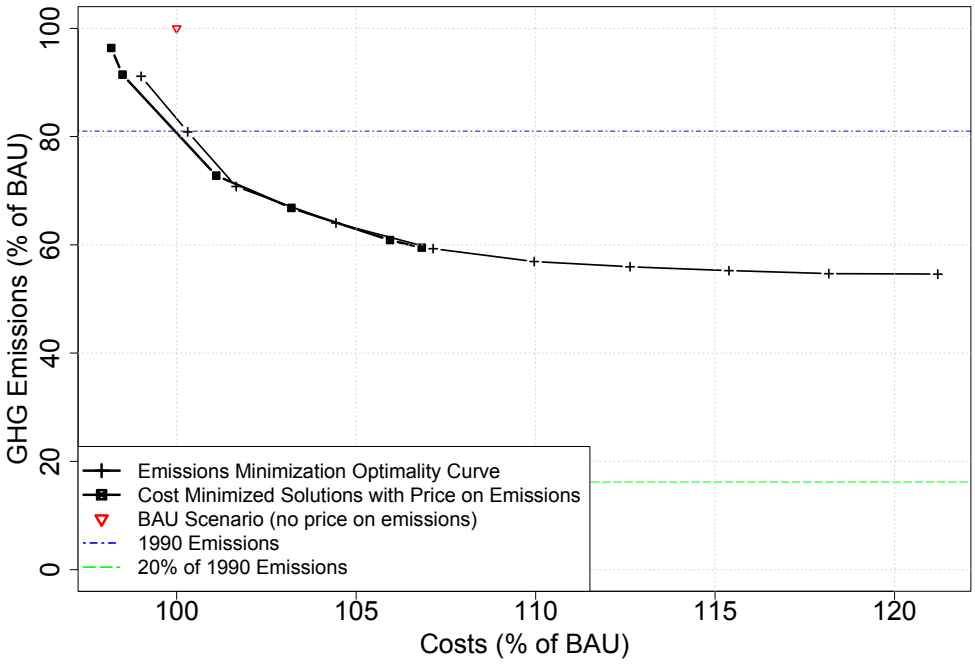
Figure 19: Cost Minimization Solutions (Black Squares) and Business-as-Usual (BAU - Red Triangles) With Various Prices Levied on GHG Emissions



BAU stands for business-as-usual. Prices have units of 2010$ / tonne CO2e.

Source: SERC staff.

Figure 20: Emissions Minimization Optimality Curve and Cost Minimization Curve With Price on Emissions



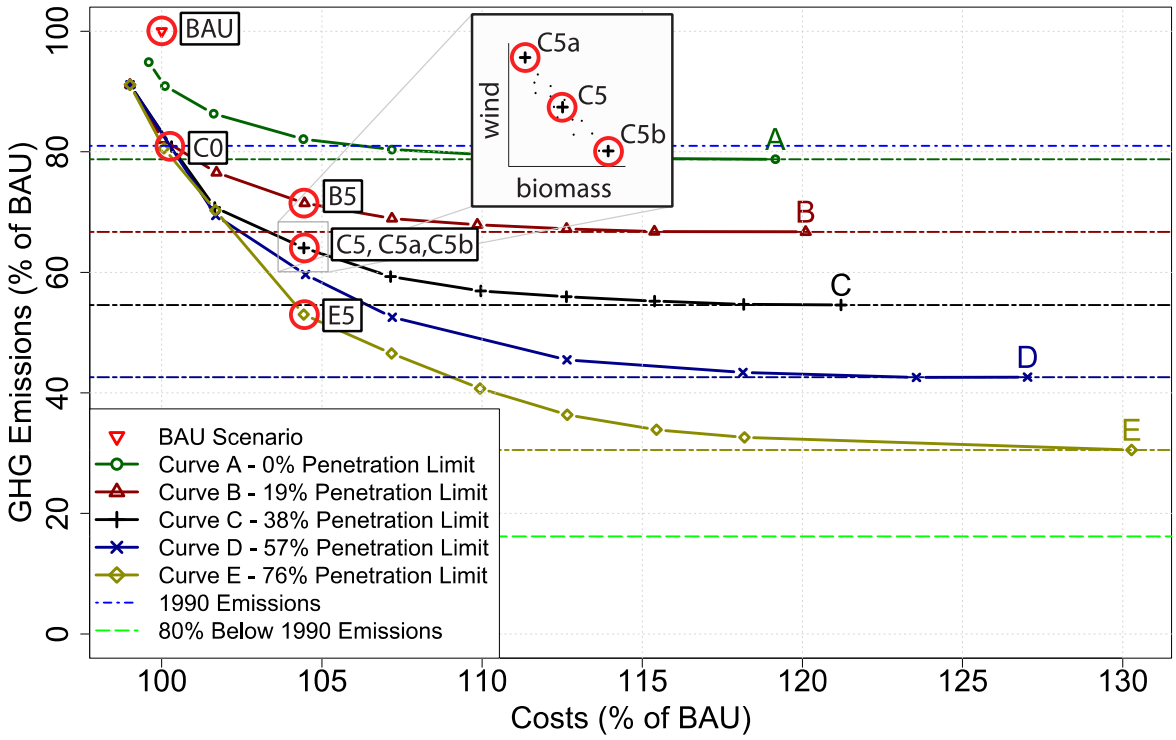
BAU stands for business-as-usual.

Source: SERC staff.

3.1.7 Preferred Scenarios

The authors selected seven scenarios to be subjected to a detailed economic analysis as reported in *Humboldt County as a Renewable Energy Secure Community: Economic Analysis Report* (Schatz Energy Research Center, 2011). These scenarios are noted in Figure 21. The naming scheme consists of an upper case letter, a number, and an optional lower case letter. The upper case letter refers to the optimality curve from which the scenario was chosen, the number represents the cost of the scenario (where x means x percent above business-as-usual cost), and the lower case letter distinguishes among multiple portfolios that have essentially the same values of costs and emissions.

These scenarios were chosen because they represent a wide range of GHG reduction potential at a reasonable increase in cost (5 percent or less). Scenarios C0 and C5 allow for a contrast between two points on the same optimality curve but with different cost constraints. To investigate the impact of electric vehicle and heat pump penetration limits, scenarios B5, C5, and E5 were chosen. Curve E represents a penetration limit of 76 percent, which the authors do not consider to be realistically achievable for Humboldt County by the year 2030. Nevertheless, that scenario is included to examine the model sensitivity to that constraint. Finally, scenarios C5, C5a, and C5b are located at essentially the same point on the optimality curve, but they explore the tradeoff that exists between wind and biomass. Among these three C5 scenarios, wind varies between 14 to 67 MW and biomass varies between 102 to 122 MW. Table 9 provides a listing of summary metrics associated with all seven scenarios.



BAU stands for business-as-usual.
Source: SERC staff.

Table 9: Summary Metrics for the Scenarios Chosen for Further Economic Analysis

Scenario	Cost M$/yr (% BAU)	Emissions kilotonnne CO2e/yr (% BAU)	% Renewables of Electricity Delivered	% Renewables of All Primary Energy
BAU	364 (100%)	1470 (100%)	36%	31%
C0	364 (100%)	1190 (81%)	57%	44%
B5	380 (105%)	1050 (71%)	87%	62%
C5,C5a,C5b	380 (105%)	940 (64%)	78%	62%
E5	380 (105%)	780 (53%)	60%	55%

BAU stands for business-as-usual.

Source: SERC staff.

3.1.8 Percentage Renewables as a Poor Metric of Success

As stated in section 1.1, the goal of the Humboldt County RESCO project is to develop a strategic plan for Humboldt County to develop its local renewable energy resources in an effort to meet 75 to 100 percent of the local electricity demand, as well as a significant fraction of heating and transportation energy needs. This goal was chosen as a proxy for achieving various benefits associated with the development of local renewable energy resources. Desired local benefits include reduction of greenhouse gas emissions, creation of local jobs and economic stimulus, reduced economic leakage associated with energy purchases, greater local control of energy supply and demand, greater stability in energy prices, and greater reliability and sustainability in local energy supply.

With regard to greenhouse gas reductions, it was expected that an increase in the use of local renewable energy resources would directly correlate to a reduction in greenhouse gas emissions. While this does hold true to an extent, it was found that obtaining the most cost-efficient reduction in greenhouse gas emissions does not directly correlate to an increase in the fraction of electricity generated from renewable sources. In retrospect, setting goals for meeting a specified portion of energy demand using local renewable energy resources may not be the best metric, especially if the most cost-efficient reductions in greenhouse gas emissions are desired. In this section, these complex results are explored further.

The results in Table 9 indicate the percent renewable energy serving the electricity grid and overall primary energy. The results, however, are not intuitive. One's expectation may be that the fraction of renewables on the grid would need to increase to decrease GHG emissions. Or if the fraction of renewables on the grid doesn't increase, at least the fraction of total primary energy from renewables must increase to see a decrease in emissions. In Table 9, the equal cost scenarios from different curves (B5, C5, and E5) indicate that both percent renewable metrics decrease as the emissions decrease.

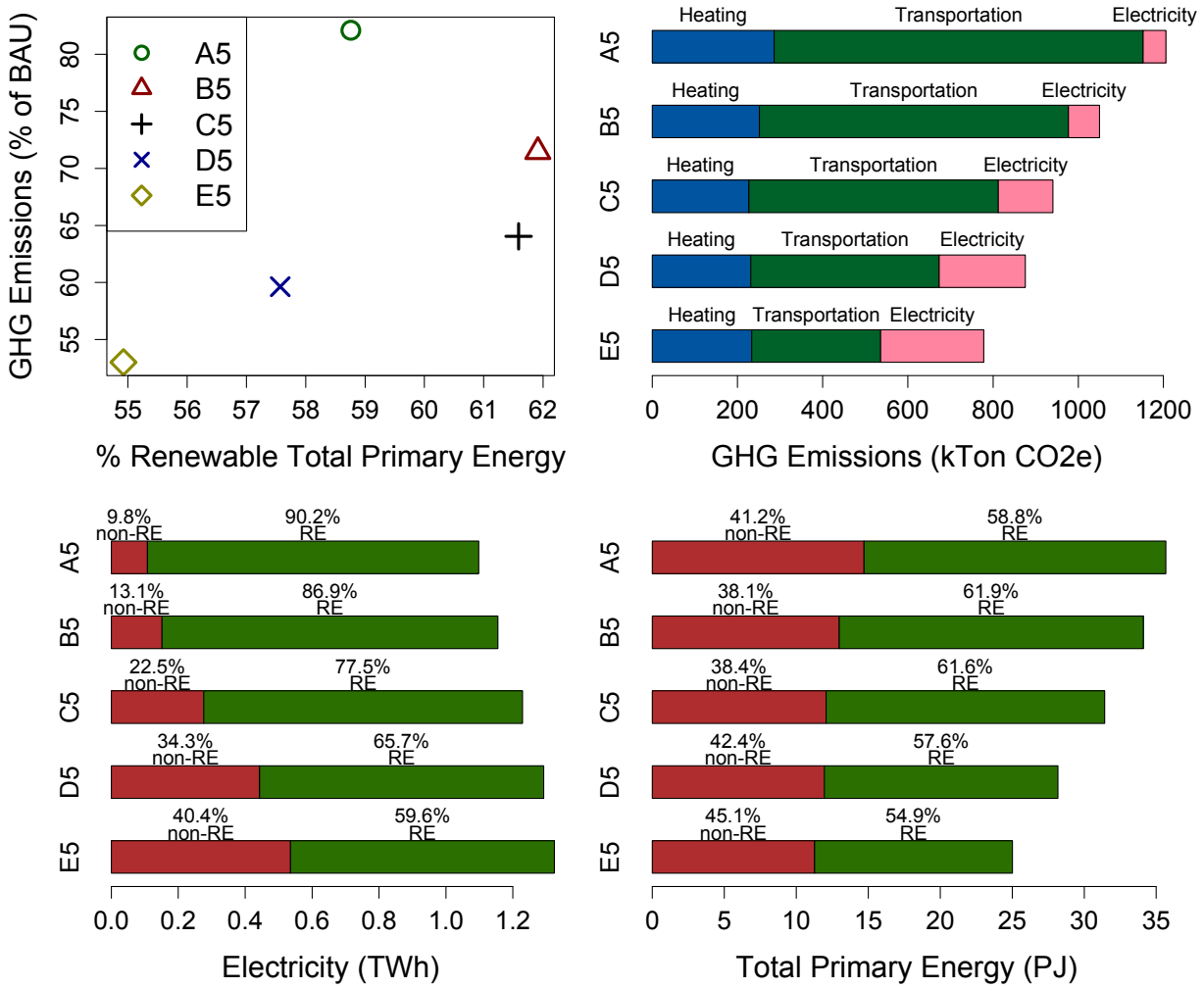
The explanation for this behavior is illustrated in Figure 22. This figure presents several results from scenarios A5, B5, C5, D5, and E5 simultaneously. The top left panel shows the relationship between emissions and the percentage of total primary energy from renewables. The top right panel contains GHG emissions for the heating, transportation, and electricity sectors. Note that the emissions from heating and transportation exclude emissions from electrified technologies. The bottom left and bottom right panels show how delivered electricity and total primary energy are distributed between renewables and non-renewables, respectively. The horizontal axes of the bottom bar plots are in units of annual energy (TWh and PetaJoules [PJ], respectively) to highlight how both total energy and the fraction of renewables change from scenario to scenario.

From point A5 to E5, the maximum allowable penetration of electric vehicles and heat pumps increases. As heating and transportation fuels are switched to electricity, there is a steep decrease in emissions associated with those sectors as well as overall emissions. The increase in emissions from the electricity sector from point A5 to E5 (Figure 22, top right panel) are due to

increases in electricity demand and also to a decrease in the fraction of renewables on the electricity grid (bottom left panel). All five of these scenarios have the same cost, and there is an expense associated with fuel switching. This means the greater the level of fuel switching, the less money there is to invest in renewable power generation. This behavior can be seen by the decreasing size (from top to bottom) of the green portion of the bars in the center panel of Figure 22. At the same time, there is also a general increase in the fraction of all primary energy from non-renewables from point to point (with an exception between A5 and B5). But even though the fraction of non-renewables is increasing, the overall non-renewable energy use is decreasing. This is due to the fact that electrified vehicles and heat pumps are substantially more efficient than their conventional alternatives, thereby consuming less primary energy. The net effect is that the absolute quantity of non-renewable primary energy decreases from scenario A5 to E5 as shown by the red bars in the bottom right panel of Figure 22. Along with this decrease in consumption of non-renewable fossil fuels comes a decrease in greenhouse gas emissions.

If the goal is to reduce GHG emissions at a reasonable cost, then it is clear that metrics such as the fraction of renewables on the electricity grid or of overall energy are misleading measures of success. Conversely, if the primary goal is to maximize the fraction of renewables, then it should be acknowledged that this would not necessarily translate into the most efficient reduction of GHG emissions. Traditionally, studies of renewable energy focus exclusively on the electricity grid where an increase in the fraction of renewables on the system will result in reduced emissions (assuming constant demand). When fuel switching is treated as an option in accomplishing the GHG minimization goal, that relationship unravels and metrics quantifying the fraction of renewables should not be taken as indicators of success.

Figure 22: Comparison of Scenarios From Different Optimality Curves of Equal Cost



Comparison in terms of emissions vs. percent renewables of total primary energy (top left), emissions from heating transportation and electricity sectors (top right), percent renewables of electricity delivered (bottom left), and percent renewables of total primary energy (bottom right).

Source: SERC staff.

3.1.9 Additional Sensitivity Analyses

The authors conducted additional analyses to investigate whether certain omissions or assumptions may have had a meaningful impact on the optimization model results. In these additional sensitivity analyses, the omission of demand response as a decision variable and the use of overly conservative heat pump costs were examined. The following describes the impact of these actions on the model results.

3.1.9.1 Demand Response

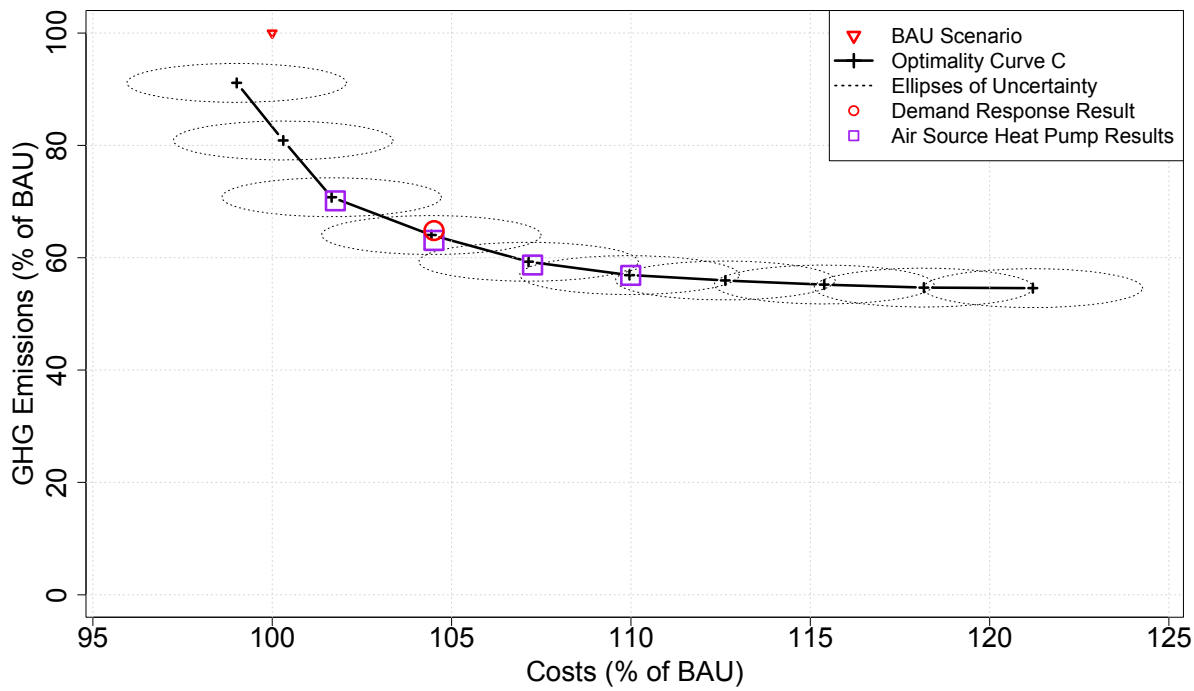
The demand response submodel is computationally intensive because it requires running the energy balance algorithm twice. It effectively doubles the length of a model run. At the same time, including demand response as a decision variable in the optimization has a negligible

impact on the final results (Figure 23). This lack of impact is not surprising given that even without the development of new generation, there is already plenty of spare capacity in the Humboldt electric power system. This is true even with substantial load growth due to aggressive adoption of electric vehicles and heat pumps (for example, 38 percent penetration). It is therefore rare when supply cannot meet demand, which is the circumstance when demand response becomes valuable. In order to reduce computation time, the authors excluded demand response as a decision variable in the optimizations.

3.1.9.2 Heat Pump Cost

The cost data used for heat pumps is a highly conservative overestimate. In order to assess the impact of this issue on the optimization results, the authors conducted several optimizations with a modified cost assumption based on the cost of air source heat pumps instead of geothermal heat pumps. Figure 23 demonstrates that the differences in outcomes are small relative to the general uncertainty of the overall results.

Figure 23: Alternative Optimization Results Compared to the Original Optimality Curve C



Demand response is included as a decision variable (red circle) or air source heat pump cost data are used instead of geothermal (purple boxes).

Source: SERC staff.

3.2 Power Flow Results

The results of the interconnection study conducted by PG&E identified a large number of CAISO Category A, Category B, and Category C violations associated with the Humboldt County Renewable Energy Secure Community (RESCO) renewable energy development

scenario that was analyzed. These CAISO violations indicate conditions on the Humboldt area electric grid that could result in power supply and/or power quality problems. Given the number of violations identified, it was clear that a plan for mitigation must be investigated. PG&E developed three alternative plans for system upgrades that would correct the violations. In addition, PG&E provided non-binding, good-faith estimates of the cost of each alternative. The full report is presented in Appendix F. The following summarizes PG&E's findings and discusses the implications for the overall Humboldt RESCO study.

3.2.1 Grid Limitations and Necessary Upgrades

As noted by PG&E (Appendix F), the electricity transmission system in Humboldt County is composed primarily of 60 kV circuits, which were designed to provide power to a geographically sparse population. The system is adequate for serving the local load, but would quickly become overloaded if mid to large generation capacity were added throughout the system. Adding 253 MW of renewable generation, as was analyzed, will require substantial upgrades to the transmission system to meet federal reliability standards. Table 10 summarizes three alternative upgrade plans investigated by PG&E.

Table 10: Transmission System Upgrade Alternatives Developed by PG&E to Mitigate Development of 253 MW of Renewable Generation

Alternative	Description	Non-binding, Good-faith Cost Estimate
1 - Reconductoring, Voltage Support and Transformer Upgrades only	Leaves voltage of the system as is but increases the capacity of transmission circuits to allow increased power flow.	$944 million
2 - Voltage Conversion, Reconductoring and Transformer Upgrades only	Convert some 115 kV transmission out of Humboldt to 230 kV. Convert several intra-county circuits from 60 kV to 115 kV.	$1002 million
3 - Build New DCTL 230 kV Line and Reconductor only	Convert circuits to 230 kV to substantially increase power flow from Rio Dell out of the County.	$260 million

Alternative 1 involves increasing the capacity of existing transmission lines through reconductoring, transformer upgrades, and the addition of voltage support. This alternative would not involve any voltage conversion (for example replacing transmission lines with new circuits at higher voltage levels). This alternative is relatively expensive because the number of system upgrades is large. This alternative is not recommended by PG&E as it is very costly and does not improve system reliability. In fact, according to PG&E, it could make the system operation more vulnerable to failures.

Alternative 2 focuses on increasing the voltage of selected transmission lines to increase the capacity of the system. The circuits identified for improvement include the export lines connecting Humboldt to Cottonwood and several other lines throughout the Humboldt Bay area and the southern end of the County. This alternative also requires extensive upgrades and is very costly.

Alternative 3 involves essentially one system upgrade, the conversion of the entire pathway between Rio Dell and Cottonwood to 230 kV. This alternative is designed to provide access to the greater California grid for the large capacity of wind power (125 MW) that was analyzed in the hypothetical development scenario. At $260 million, this alternative is the least expensive by a factor of 4, however, it is a custom solution and may not be suitable for a renewable portfolio that involves less wind development and greater development of other resources in other locations. On the other hand, the substantial difference in cost between alternative 3 and the other alternatives highlights the importance of a planning process capable of anticipating the location and extent of all (or most) of the new generation capacity. If generation projects are planned one at a time, in isolation, then alternative 1 may be the most likely pathway toward accommodating future projects. However, if project planning is coordinated across the county, there could be opportunities for substantial overall savings.

3.2.2 Study Implications and Limitations

The roughly $1 billion cost for alternatives 1 and 2 may appear to be prohibitive and unrealistic. However, if a 40-year economic lifetime is assumed for the infrastructure and operations and maintenance (O&M) costs are considered negligible, then these alternatives would have a lifecycle cost of about $25 million per year (assuming a 7 percent discount rate), which is approximately 7 percent of the total business-as-usual lifecycle cost for energy services in Humboldt County. It is important to note that the power flow study was not completed until after the completion of the energy planning optimization program (REPOP) modeling analysis presented in this report. Therefore, the cost results presented throughout this report do not include the costs of transmission system upgrades necessary to accommodate high penetrations of renewable resources. In the worst cases, the cost figures would increase by only 5 percent to 10 percent (with respect to business as usual) to account for transmission system upgrade costs.

While this cost underestimate is not negligible, the authors believe that a full inclusion of transmission upgrade costs would not appreciably change the overall conclusions of this study, namely, that substantial development of local renewable energy resources is both technically possible and economically feasible. It should also be noted that some or all of these system upgrades could count as network upgrades under the California Independent System Operators (CAISO) Tariff. While project developers are responsible for covering the upfront cost of network upgrades, they are repaid for the upgrades in the first few years of the project. This means the entire rate base, not just project developers or the citizens of Humboldt County, would share the economic burden of the upgrades.

Furthermore, the authors believe that the methodological approach PG&E is required to follow to satisfy national reliability requirements is excessively conservative and may substantially

overstate the need for system upgrades. The problem is that the analysis is based on a worst-case scenario that assumes *every* proposed generator (including the energy storage facility) in Humboldt County is producing electricity at full capacity. Essentially, the grid is assumed to be entirely unmanaged. This approach ignores legitimate and potentially cheaper solutions to reliability concerns such as using energy storage facilities as load (instead of generation) or curtailing generators during periods of excess power on the system. For example, the REPOP model assumes that most generators – especially the 163 MW natural gas power plant – can be curtailed when the total potential for power production exceeds the demand and ability to export.

The North American Electric Reliability Corporation (NERC) is the entity ultimately responsible for reliability standards on the grid. As stated in a recent report (NERC, 2009), NERC is well aware of these and other important issues relevant to the interconnection of variable power sources. They are currently working on solutions to the transmission planning process that will facilitate, rather than hinder, the rapid development of renewable power sources. Assuming the planning process is amended in the future, it is reasonable to assume that the upgrade cost estimates discussed above represent an absolute upper limit to the cost of accommodating renewable energy development in Humboldt County.

Another aspect that should be considered in the context of significant upgrades to the Humboldt area transmission and distribution system is the possibility of creating a community scale microgrid in Humboldt that can operate independent from the statewide electric grid if necessary. While alternative 3 is clearly the cheapest option for overcoming the grid reliability problems associated with large-scale renewable energy development in Humboldt, it would likely not lead to a functioning microgrid. For this reason, an upgrade plan more like alternatives 1 and 2 might be preferred if microgrid functionality is desired.

3.3 Hydrogen Transit Results

Results of the hydrogen fuel cell bus analysis are given in Table 11 below. The largest cost for a hydrogen transit system is associated with the buses themselves. The cost of a hydrogen fuel cell bus (even assuming the cost decreases significantly as they become commercial) is 25 percent higher than the current cost of a new hybrid diesel bus. The initial cost of required fueling infrastructure is also high, almost $800,000 for a small hydrogen system and over $3 million for a full hydrogen transit system. These initial costs would likely be the biggest hurdle to developing a hydrogen powered transit system. As a revenue negative system (mass transit system do not generally bring in enough revenue to be self-supporting; they rely on governments to make up the cost difference to provide a service seen as a public good), Humboldt Transit Authority would need to find outside funding to pay the initial costs.

Annual operating costs for a hydrogen transit system are higher than for a diesel-based system. Both fuel costs and operations and maintenance costs are higher on a per mile basis for a fuel cell bus than a diesel bus. However, as fuel cell bus technology matures operations and maintenance costs will likely decrease and fuel economy will likely increase, resulting in lower operating cost. The cost of hydrogen fuel will also decrease if the energy required to generate

and compress hydrogen decreases. This will happen as manufacturers make equipment more efficient, which they are already doing in response to the growing interest in hydrogen fuel.

Transitioning to a hydrogen transit system would decrease carbon dioxide emissions, but at a high cost. A full hydrogen system would result in a 32 percent decrease in CO_2 emissions at a 21 percent increase in cost compared to business-as-usual. A system with 10 percent of the miles travelled fueled by hydrogen would result in 3 percent decrease in CO_2 emissions at a 2 percent increase in cost. This corresponds to costs ranging from $1,700 to $2,000 per ton of avoided CO_2 emissions. This is significantly higher than the current price of CO_2 (approximately $20 per ton in European markets) and most projections of the future price of CO_2.

Table 11: Results of Hydrogen Transit Analysis

H2 Penetration	BAU	10%	15%	25%	50%	75%	100%
Diesel cost ($/year)	$682,527	$614,275	$1,062,500	$937,500	$625,000	$312,500	$0
Diesel cost ($/mile)	$0.55	$0.55	$0.55	$0.55	$0.55	$0.55	$0.55
Hydrogen ($/kg)	N/A	$9.89	$9.42	$9.05	$8.76	$8.67	$8.62
Hydrogen ($/mile)	N/A	$1.27	$1.21	$1.16	$1.13	$1.12	$1.11
Annual costs diesel fleet	$5,720,027	$5,148,025	$4,862,023	$4,290,020	$2,860,014	$1,430,007	$0
Annual costs H2 fleet	N/A	$712,831	$1,057,948	$1,748,182	$3,473,766	$5,199,351	$6,924,935
Annual total costs (H2 and Diesel)	$5,720,027	$5,860,855	$5,919,971	$6,038,202	$6,333,780	$6,629,358	$6,924,935
Total costs ($/mile)	$4.58	$4.69	$4.74	$4.83	$5.07	$5.30	$5.54
% of BAU Cost	100%	102%	103%	106%	111%	116%	121%
Annual CO2 emissions (lbs. CO2)	4,329,173	4,189,692	4,119,952	3,980,471	3,631,768	3,283,065	2,934,363
CO2 emissions (% of BAU)	100%	97%	95%	92%	84%	76%	68%
Fleet average CO2 emissions (lbs/mile)	3.46	3.35	3.30	3.18	2.91	2.63	2.35
Cost of avoided CO2 ($/lbs CO2 avoided)	N/A	$1.01	$0.96	$0.91	$0.88	$0.87	$0.86
Cost of avoided CO2 ($/tCO2)	N/A	$2,019	$1,911	$1,825	$1,760	$1,739	$1,728
Capital costs (not including buses)	N/A	$781,970	$922,173	$1,202,581	$1,903,600	$2,604,619	$3,305,638
Number of H2 buses	N/A	3	5	9	17	26	34
Cost of hydrogen buses	N/A	$2,568,493	$3,852,740	$6,421,233	$12,842,466	$19,263,699	$25,684,932

Source: SERC staff.

Because of uncertainty in the variables used for this analysis, it is instructive to perform a sensitivity analysis. A sensitivity analysis explores how the results change as the input variables change. The authors performed a sensitivity analysis focusing on four variables: the fuel economy of the hydrogen buses, the cost of electricity, the amount of energy required to generate and compress hydrogen, and the price of diesel fuel. Because of the high costs found in the initial analysis, these variables were only changed in a way that would make the results more cost-effective. The results were compared to the base case results from the original analysis. Table 12 shows the parameter values used in the original analysis (base case) and the optimistic values used for the sensitivity analysis.

Table 12: Variables Used in Hydrogen Bus Sensitivity Analysis

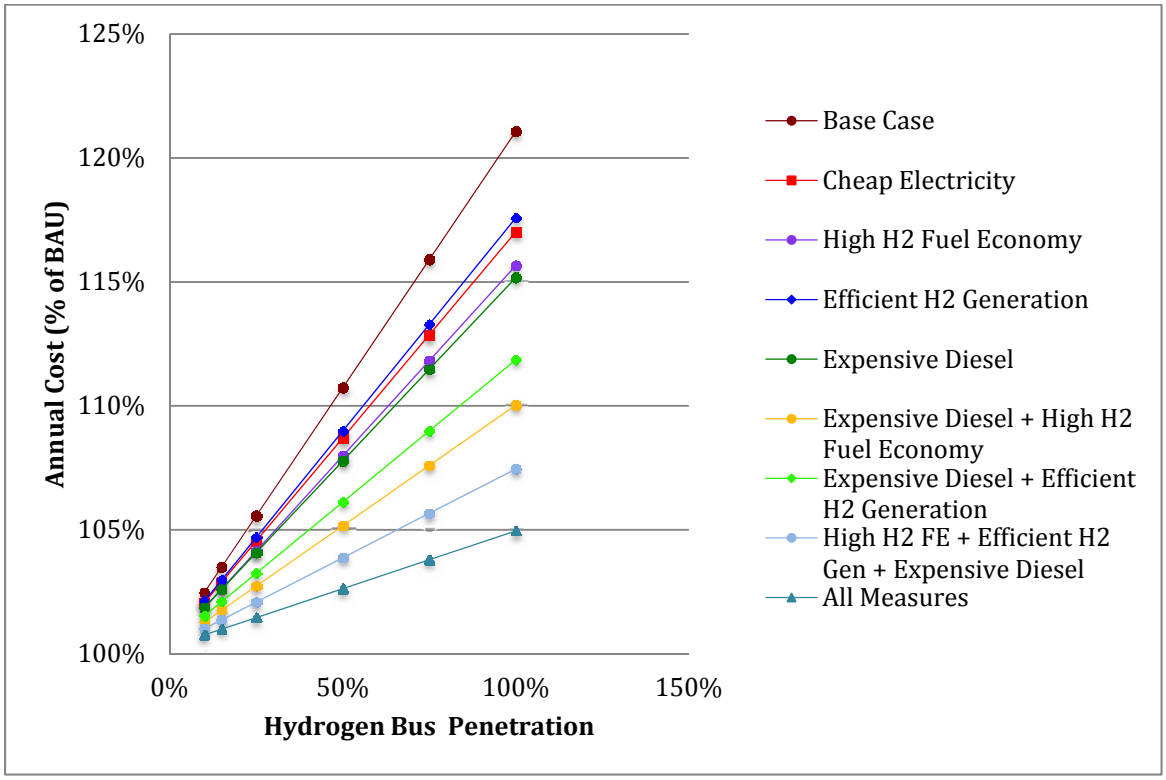
Variable	Base Case Value	Optimistic Value
Cost of Electricity ($/kWh)	0.124	0.100
Fuel Economy of H_2 Bus (Miles/kg H_2)	7.77	10
H_2 generation Energy (kWh/kg H_2)	60	50
Cost of Diesel ($/gallon)	3.5	5

Source: SERC staff.

Changing any of the variables decreases the operating costs of the hydrogen transit, but no one variable reduces the cost to BAU. Increasing the cost of diesel gas has the greatest impact. When the cost of diesel is increased to $5 per gallon, the cost of the hydrogen system is 15 percent higher than BAU for the full hydrogen scenario. If measures are combined there is a greater impact on the cost. Using the optimistic values for all the variables results in a cost that is 5 percent higher than BAU. Figure 24 shows the results from all the scenarios investigated in the sensitivity analysis.

The cost of diesel fuel is the most volatile variable in this analysis, so an analysis was performed to estimate the cost of diesel that allows a hydrogen transit system to break-even with BAU. This again excluded initial capital costs. For the smallest hydrogen system (10 percent penetration), diesel fuel would need to cost $10.72 per gallon, whereas a full hydrogen system would require a diesel price of $9.68 per gallon to break-even. While these numbers represent a several fold increase in the price of diesel fuel, they are not out of line with prices elsewhere in the world. As of March 2011, the price of diesel in the United Kingdom is around $8.25 per gallon and oil prices are rising due to unrest in Northern Africa.

Figure 24: Results of Hydrogen Bus Sensitivity Analysis



Source: SERC staff.

This analysis shows that creating the infrastructure for a hydrogen transit system is expensive and does not provide an economic benefit. Funding would need to be found for the initial costs of the fueling infrastructure and the fuel cell buses. If only the costs associated with fuel and operations and maintenance are considered, it could be economically feasible if the fuel economy of the buses increased, electrolysis and compression becomes more efficient, and the cost of diesel fuel increases. Increases in hydrogen bus fuel economy seem likely as the technology matures. Electrolyzer and compressor manufacturers are making their products more efficient in response to consumer demand, largely driven by the renewable energy sector. There is also precedent for rising gas prices. It would take some combination of all these factors for a hydrogen transit system to become economically viable in Humboldt County.

3.4 Forest-Based Biofuels Results

Section 2.3.2.3 (Forest-based Biofuels) and Appendix B.2 (Forest-based Biofuels Assessment) present two primary alternatives for utilizing the forest biomass resource in Humboldt County to power vehicles: (1) combustion of biomass for electricity generation to power electric vehicles and (2) production of biofuels through biochemical, thermochemical, and Fischer-Tropsch conversion processes. Based on these two alternatives, five related fuel pathways (Table 13) were developed and assessed using

the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model (GREET).

Table 13: Description of Fuel Pathways Modeled in GREET

Fuel Pathway	Description
Baseline: CG and RFG for CVs	Conventional and reformulated gasoline are used to fuel spark ignition conventional vehicles
E85 (gasification) for FFVs	A gasification based process is used to produce ethanol from forest biomass; ethanol is used to fuel spark ignition flex-fuel vehicles
E85 (fermentation) for FFVs	A fermentation based process is used to produce ethanol from forest biomass; ethanol is used to fuel spark ignition flex-fuel vehicles
FTD100 for CIDIVs	The Fischer-Tropsch process is used to produce Fischer-Tropsch Diesel from forest biomass; FTD is used to power compression-ignition direct-injection vehicles
CG/RFG and Electricity for SI PHEVs	Conventional/reformulated gasoline and electricity from the combustion of forest biomass are used to power spark ignition plug-in hybrid electric vehicles
Electricity for BEVs	Electricity from the combustion of forest biomass is used to power battery electric vehicles

Source: SERC staff.

Per mile lifecycle energy and GHG impacts of each fuel pathway considered are shown in Table 14. Lifecycle impacts for vehicles are often referred to as well-to-wheels (WTW) impacts, though in the case of biomass the well is the forest. Relative to the baseline, all three of the biofuel scenarios are more energy intensive, with the fermentation based ethanol pathway requiring the most energy (83 percent more than the baseline). Meanwhile, the PHEV and BEV pathways reduce energy use by 12 percent and 15 percent, respectively. All pathways significantly reduce fossil fuel use and GHG emissions relative to the baseline. BEVs have the largest impact, reducing fossil fuel use and GHGs by 95 percent and 92 percent, respectively, followed by the Fischer-Tropsch diesel (FTD) pathway, which results in reductions of 92 percent and 91 percent. The smallest impact, though still significant, is made by the PHEV pathway with a 47 percent reduction in fossil fuels and 46 percent reduction in GHGs. Clearly all of these fuel and vehicle combinations have the potential to drastically reduce transportation sector GHG emissions. The costs associated with the development of each fuel and vehicle pathway is an important criterion by which to further assess these options. A comparative lifecycle benefit/cost analysis should be conducted. Such an analysis is carried out for PHEVs and BEVs in Section 2.4 (Transportation Cost Analysis) of the RESCO Economic Analysis Report (SERC, 2011). A comparable lifecycle benefit/cost analysis should also be conducted for the identified biofuel pathways to further assess these options.

Appendix B.2.3 contains more detailed well-to-wheels (Table 25) and well-to-pump (Table 26) results for each fuel and vehicle pathway.

Table 14: Well-to-Wheels Total Energy, Fossil Fuels, and GHG Emissions for Several Pathways

Fuel Pathway	Total Energy (BTU/mi)	Relative to Baseline	Total Fossil Fuels (BTU/mi)	Relative to Baseline	GHGs (g/mi)	Relative to Baseline
Baseline: CG and RFG for CVs	5279	0.0%	4909	0.0%	405	0.0%
E85 (gasification) for FFVs	6557	24.2%	1794	-63.5%	149	-63.2%
E85 (fermentation) for FFVs	9684	83.4%	1050	-78.6%	111	-72.5%
FTD100 for CIDIVs	7367	39.5%	398	-91.9%	36	-91.0%
CG/RFG and electricity for SI PHEVs	4655	-11.8%	2594	-47.2%	219	-46.0%
Electricity for BEVs	4483	-15.1%	226	-95.4%	33	-91.7%

Percent change is relative to a baseline of conventional vehicles fueled with conventional and reformulated gasoline.

Source: SERC staff.

CHAPTER 4:
Conclusions and Recommendations

4.1 Conclusions

The overall goal of the technical and resource assessment was to explore the range of supply and demand options available for increasing Humboldt County's energy security through the development of local renewable energy resources. The research team developed and employed a custom energy balance and optimization model called the Regional Energy Planning Optimization (REPOP) model. It was used to assess resource and technology portfolios based on criteria, including the overall cost of supplied energy and greenhouse gas impacts. The results of this resource and technology assessment will inform the development of the Humboldt RESCO strategic plan.

4.1.1 Key Findings

Humboldt County has a wealth of local renewable energy resources. It is geographically isolated and severely constrained with regard to energy transmission capacity in and out of the county. Nearly all of Humboldt County's transportation fuels and the majority of its heating fuels are imported. Given these circumstances, the key issues Humboldt County faces in meeting its energy goals are not related to the adequacy of local resources, but instead to the ability to develop these resources and the associated energy infrastructure needed serve local demand with local renewable energy sources.

Key lessons learned in this study include the following:

- Humboldt County can meet 75 percent or more of its electricity needs and a large fraction of its heating and transportation energy demand using local renewable energy resources.
    - This can result in a substantial reduction in greenhouse gas emissions (for example, a 35 percent reduction below business-as-usual, which is equivalent to about a 20 percent reduction below estimated 1990 emissions levels).
    - This can be achieved at a modest cost increase (approximately 5 percent above business-as-usual), with greater reductions possible at higher cost.
- There are many possible resource and technology options to choose from, and a mixed portfolio of options is likely more advantageous than any technology in isolation. Aggressive implementation of cost-effective energy efficiency opportunities should be a near-term pursuit. Biomass, wind and small run-of-the-river hydroelectric energy sources should play a key supply-side role.
- The RESCO goal of meeting 75 percent or more of electric demand with local renewable resources may not be the best metric for measuring success. Instead

- Fuel switching to plug-in hybrid and battery only electric vehicles in the transportation sector and to electric heat pumps in the heating sector has the potential to play a major role in realizing the RESCO vision. Fuel switching opportunities are critical to cost-effectively achieving large reductions in energy related greenhouse gas emissions. Without fuel switching, deep reductions in greenhouse gas emissions are infeasible.
- Humboldt County's RESCO goals can be achieved with only a modest cost increase. The majority of greenhouse gas reductions can be realized with only a 5 percent to 15 percent increase in overall energy costs, and beyond this level there are diminishing returns. With a cost increase of only 5 percent and a 40 percent penetration of electric vehicles and heat pumps, Humboldt County can achieve an 80 percent share of local renewable electricity and a 36 percent decrease in greenhouse gas emissions. Doubling the percentage cost increase to 10 percent can achieve a 95 percent share of local renewable electricity and a 43 percent decrease in greenhouse gas emissions.
- Distributed generation, like rooftop solar, can play a smaller but important role. These technologies can provide direct economic benefits to retail customers. In addition, they provide an active way for individuals and businesses to participate in the implementation of the RESCO vision. Appropriate levels of support for these technologies can help cultivate broad backing for the overall RESCO plan.
- A steady state power flow analysis conducted by PG&E indicates that substantial upgrades to the local transmission and distribution system will be required to accommodate large-scale development of local renewable energy sources. The most cost-effective plan for these upgrades would likely involve an area-wide planning approach that simultaneously considers multiple projects. If instead a project-by-project approach is taken, a less optimal piecemeal solution is likely to result. It is also important to note that non-standard approaches to maintaining grid stability, such as curtailing generation, should be considered in the analysis. Finally, transmission planning should also consider the possibility of creating a community-scale microgrid in Humboldt that can operate independent of the statewide grid if necessary.
- Energy storage will not likely play a significant role unless local renewable generation provides the vast majority (for example, greater than 90 percent) of local electricity demand.

- Regarding pathways for the use of forest-based biomass to provide energy for the transportation sector, the Fischer-Tropsch biodiesel pathway compares favorably with the biopower to battery electric vehicle pathway, with both of these pathways achieving greater than 90 percent reduction in fossil fuel use and greenhouse gas emissions. The cellulosic ethanol pathway does not fare as well in comparison, though it does beat out the plug-in hybrid electric vehicle pathway.

4.1.2 Modeling Results

4.1.2.1 Business-as-Usual

If there is no further development of clean energy alternatives in Humboldt County, model estimates for the business as usual scenario in 2030 show an electric supply dominated by power from the natural gas fired PG&E Humboldt Bay Generating Station (65 percent) and existing biomass power plants (30 percent). In the business-as-usual scenario the energy supply for the heating and transportation sectors will continue to be dominated by fossil fuels in the form of natural gas (75 percent) and gasoline (100 percent). Transportation fuels will continue to dominate annual energy costs, and transportation fuels and natural gas usage will drive greenhouse gas emissions to 1500 kilotonnes of CO_2e per year (25 percent greater than 1990 levels). Clearly the business-as-usual scenario will not improve local energy sustainability, but instead will exacerbate the environmental problems associated with the current energy system while maintaining Humboldt County's exposure to fuel scarcity and price volatility.

4.1.2.2 Clean Energy Development

Humboldt County possesses ample renewable energy resources to meet the majority of its electricity demands and a large portion of its transportation and heating energy needs. Modeling results have shown that key local renewable energy resources include biomass, wind, and hydropower. In addition, while biomass resources can provide baseload electric power and intermittent renewables like wind and solar can provide as-available power, PG&E's new natural gas fired engine generators at the Humboldt Bay Generating Station can provide load following capability to fill the gaps when demand peaks or power from intermittent renewables fluctuates. Not surprisingly, modeling results indicate that all cost-effective energy efficiency measures should be implemented as this is the most inexpensive way to provide energy services and reduce greenhouse gas emissions.

In the transportation and heating sectors, fuel switching from fossil fuels (petroleum and natural gas) to electricity via the adoption of electric vehicles and heat pumps enables greater development of local renewable electricity sources while also deeply reducing fossil fuel use and associated greenhouse gas emissions. Perhaps more importantly, it has been shown that the adoption of electric vehicles and heat pumps can allow for a more cost-effective reduction in greenhouse gas emissions than to simply focus on renewable electricity supplies. This leads to a conclusion that the initially stated RESCO

goal of meeting 75 percent or more of electric demand with local renewable resources may not be the best target for environmental and economic reasons. Instead of focusing on the percentage of electricity served by local renewable resources, the research team suggests it is better to focus on the most cost-effective ways to decrease greenhouse gas emissions, which would include aggressive adoption of electric vehicles and heat pumps in addition to the development of local renewable energy supplies. Furthermore, without fuel switching in the heating and transportation sectors it has been shown that only a 20 percent reduction in greenhouse gas emissions is achievable regardless of the level of renewable energy development. Clearly the adoption of electric vehicles and heat pumps is critical to achieving greenhouse gas reduction goals.

The results of this analysis indicate that the ambitious development of local renewable energy resources and the adoption of electric vehicles and heat pumps would make great strides toward meeting renewable energy and climate action goals, and that this can be achieved at a modest cost increase. In fact, the optimization modeling shows that the majority of greenhouse gas reductions are realized with only a 5 percent to 15 percent increase in overall energy costs, and that beyond this level there are diminishing returns. With a cost increase of only 5 percent and a 40 percent penetration of electric vehicles and heat pumps, Humboldt County can achieve an 80 percent share of local renewable electricity and a 35 percent decrease in greenhouse gas emissions compared to business-as-usual. Doubling the allowable cost increase to 10 percent can achieve a 95 percent share of local renewable electricity and a 45 percent decrease in greenhouse gas emissions. In addition, as documented in *Humboldt County as a Renewable Energy Secure Community: Economic Analysis Report* (Schatz Energy Research Center, 2011), aggressive development of local renewable energy sources would also create a substantial number of permanent local jobs and significantly stimulate the local economy by reducing the economic leakage associated with energy dollars leaving the county.

Small-scale distributed generation technologies (defined here as less than5 MW generators connected to the distribution system at or very near to the load) did not play a major role in the RESCO modeling effort. The only technology fitting this description that was modeled was rooftop solar photovoltaic systems. Given that Humboldt County does not have a robust solar resource in the Humboldt Bay area where the population is centered (for example, approximately 4 peak sun hours per day on average) and rooftop solar is the most expensive generation technology that was considered, solar photovoltaic systems did not play a significant role in the optimal mixes of generation resources. Nonetheless, solar and other distributed generation technologies can play an important role in the Humboldt RESCO plan. They are technologies that can provide direct economic benefits to retail customers. In addition, they provide an active way for individuals and businesses to participate in the implementation of the RESCO vision. In this way they can empower people and help generate broad support for the overall RESCO plan.

With a current peak load of 170 MW and an average load of about 110 MW, the normal transmission capacity of 60 MW to 70 MW between Humboldt County and the rest of

California poses a severe constraint on the operation of the local electric grid. Clearly a large portion of Humboldt County's electrical power must be generated locally. In addition, there are serious limitations to the amount of excess renewable generation (for example, from intermittent wind facilities) that could be exported. With large increases in local renewable electricity generation this could require that local renewable capacity be curtailed during high generation and/or low demand situations. However, this analysis found that an increase in transmission capacity is neither necessary nor cost-effective in pursuing Humboldt RESCO goals assuming sufficient local demand is built by fuel switching in the heating and transportation sectors. Current transmission capacity was essentially found to be adequate as increases in the transmission capacity were never a part of the optimal solutions found by the REPOP model.

Energy storage was also examined as a way to minimize the curtailment of local intermittent renewable generation during high generation, low demand situations. However, like with transmission capacity, energy storage was not shown to play a significant role. For example, in the scenario with 38 percent penetration of electric vehicles and heat pumps, energy storage only became a part of the optimal solution when local renewable generation provided greater than 95 percent of electricity demand. Nonetheless, three energy storage technologies were identified that could be implemented in Humboldt County: pumped hydro, compressed air, and batteries. Of these, pumped hydro appeared to be the most cost-effective provided it turns out to be politically and technically viable.

A steady state power flow analysis conducted by PG&E indicates that substantial upgrades to the local transmission and distribution system will be required to accommodate large scale development of local renewable energy sources as suggested by this study. These upgrades will be required to ensure that PG&E's transmission system remains in full compliance with North American Electric Reliability Corporation (NERC) reliability standards.

Finally, two pathways were examined for the use of forest-based biomass to provide energy for the transportation sector. One pathway included the production of biopower and subsequent charging of electric vehicles, whereas the alternate pathway involved the production of forest-based biofuels, either cellulosic ethanol or Fischer-Tropsch biodiesel, to be used in internal combustion engine vehicles. The use of Argonne National Laboratory's GREET model was used to compare these pathways and the results indicate that the Fischer-Tropsch biodiesel pathway compares favorably with the biopower to battery electric vehicles pathway, with both of these pathways potentially achieving greater than 90 percent reduction in fossil fuel use and greenhouse gas emissions. The cellulosic ethanol pathway did not fare as well, though it did outperform the plug-in hybrid electric vehicle pathway.

4.2 Recommendations

The results and conclusions from this study will help inform the creation of a long-term Humboldt County RESCO strategic plan to move toward a more sustainable and secure energy future. The RESCO study seeks to achieve benefits including reductions in greenhouse gas emissions, job creation and economic stimulus, and greater local control of energy decisions. Key recommendations to be drawn from this work include:

- The results of the Humboldt RESCO resource and technology assessment should be used to inform the development of the Humboldt County RESCO Strategic Plan.
- The goals of the Humboldt County RESCO Strategic Plan should focus on the most cost-effective way to achieve greenhouse gas emission reductions in combination with the development of local renewable energy resources. Meeting a certain percentage of electricity demand using local renewable resources should not be the primary goal.
- Elements of the RESCO Strategic Plan should include:
    - Aggressive pursuit of cost-effective energy efficiency opportunities.
    - Development of new biomass, wind and small hydroelectric generating facilities.
    - A focused effort to encourage adoption of electric vehicles and heat pumps.
    - Appropriate levels of support for distributed generation, like rooftop solar, as a means of engaging and garnering community backing for the overall RESCO vision.

4.3 Suggestions for Further Study

While the Humboldt RESCO resource and technology assessment study was comprehensive in its scope, it was by no means exhaustive. Opportunities for further research include:

- Further review and refinement of the assumptions used in the Regional Energy Planning Optimization model.
- Improvements or added capabilities to the Regional Energy Planning Optimization model.
- Identifying ways to cost-effectively and sustainably utilize forest fuel reduction material from remote locations as a fuel source for biopower or biofuel production.
- A biomass fuel availability assessment that estimates the technical, economic and achievable quantity of biomass fuel that can be successfully utilized for

renewable energy generation. This should include an assessment of various fuel sources, including material from both public and private timber lands, as well as waste materials generated during timber harvests (slash), fuel treatments, and thinning of stands. The estimate of achievable quantities should include impacts associated with community acceptance.

- A life-cycle assessment of greenhouse gas emissions associated with biomass power should be conducted and the assumption that biomass energy is climate neutral should be examined.
- An assessment of small hydroelectric opportunities and barriers.
- Adaptation of the Regional Energy Planning Optimization model for use in another California community.
- A more robust power flow analysis to include a transient stability analysis, as well as examination of non-conventional means of meeting North American Electric Reliability Corporation (NERC) reliability standards (for example, through energy storage facilities or flexible contracting arrangements with curtailment).
- Further research into the Fischer-Tropsch biodiesel forest-based biofuel pathway for using local biomass resources to meet transportation energy needs. An examination into the cost and feasibility of this pathway is needed.

4.4 Benefits to California

While the focus of this study was to provide guidance to Humboldt County, the tools developed and lessons learned can provide substantial benefit to communities throughout California and beyond. Some of the benefits to other communities include:

- Development of simulation models and planning tools for community energy and greenhouse gas reduction planning.
- Lessons learned that can be applied to other communities.
- A case study of how large percentages of local renewable resources coupled with the adoption of electric vehicles and heat pumps can lead to cost-effective reductions in greenhouse gas emissions and substantial local economic benefits.
- Using Humboldt County as a test case for operating an electric grid with high fractions of renewable energy generation.
- Additional products from the RESCO study will include a regulatory and policy guide for local government officials, a strategic planning document for the development of local renewable energy resources, and a RESCO planning workbook that will document RESCO planning activities and make them easily accessible to other communities.

CHAPTER 5: Glossary

BAU	Business-As-Usual
BDT	Bone Dry Ton
BEV	Battery Electric Vehicle
CAES	Compressed Air Energy Storage
California ISO	California Independent System Operator
CDD	Cooling Degree-Day
CG	Conventional Gasoline
CH_4	Methane
CHP	Combined Heat And Power
CIDIV	Compression-Ignition Direct-Injection Vehicle
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COP	Coefficient Of Performance
CZ	Climate Zone
DEER	Database For Energy Efficient Resources
DHW	Domestic Hot Water
DOE	Department Of Energy
EF	Energy Factor
Energy Commission	California Energy Commission
EPRI	Electric Power Research Institute
EREV	Extended Range Electric Vehicle
EV	Electric Vehicle
FCHV	Fuel Cell Hybrid Vehicle
FFV	Flex Fuel Vehicle

FTD	Fischer-Tropsch Diesel
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, And Energy Use In Transportation
H2	Hydrogen
HDD	Heating Degree-Day
HTA	Humboldt Transit Authority
HVAC	Heating, Ventilation And Air Conditioning
ICE	Internal Combustion Engine
IOU	Investor Owned Utilities
LPG	Liquefied Petroleum Gas
N2O	Nitrous Oxide
NaS	Sodium Sulfur
NERC	North American Electric Reliability Corporation
NO_x	Nitrogen Oxides
NRDC	Natural Resource Defense Council
NREL	National Renewable Energy Laboratory
O&M	Operations And Maintenance
PG&E	Pacific Gas & Electric
PHES	Pumped Hydroelectric Energy Storage
PHEV	Plug-In Hybrid Electric Vehicle
PJ	PetaJoules
PM10	Particulate Matter With A Diameter Less Than Or Equal To 10 Micrometers
PM2.5	Particulate Matter With A Diameter Less Than Or Equal To 2.5 Micrometers
PV	Photovoltaic
RE	Renewable Energy

REPOP	Regional Energy Planning Optimization Program
RESCO	Renewable Energy Secure Community
RFG	Reformulated Gasoline
SCG	Southern California Gas Company
SDG&E	San Diego Gas & Electric Company
SEC	Southern California Edison
SEER	Seasonal Energy Efficiency Ratio
SERC	Schatz Energy Research Center
SIPHEV	Spark Ignition Plug-In Hybrid Electric Vehicle
SO_x	Sulfur Oxides
TRC	Total Resource Cost
VOCs	Volatile Organic Compounds
WTW	Well-To-Wheels
ZEV	Zero Emission Vehicle

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APPENDIX A:
Electric Vehicle Assessment

A.1 Analysis Methodology

A.1.1 Baseline

To assess the impacts that electric vehicles (EVs) could have in Humboldt County it was first necessary to characterize the existing vehicle fleet as a basis for comparison. To establish such a baseline, county level transportation data were collected from the California Department of Motor Vehicles and the California Department of Transportation. Using these data, registered vehicles, annual vehicle miles traveled, and annual vehicle fuel consumption were extrapolated to estimate future growth. National fuel economy estimates by the Bureau of Transportation Statistics were also used to estimate future baseline fleet vehicle fuel consumption in Humboldt County. An annual vehicle fuel consumption growth rate of 0.5 percent was used based on average annual vehicle fuel consumption growth from 1999 to 2006. This suggests that about 76.3 and 80.2 million gallons of fuel would be consumed in 2020 and 2030, respectively. This corresponds to an average of 11,000 miles of travel per vehicle-year.

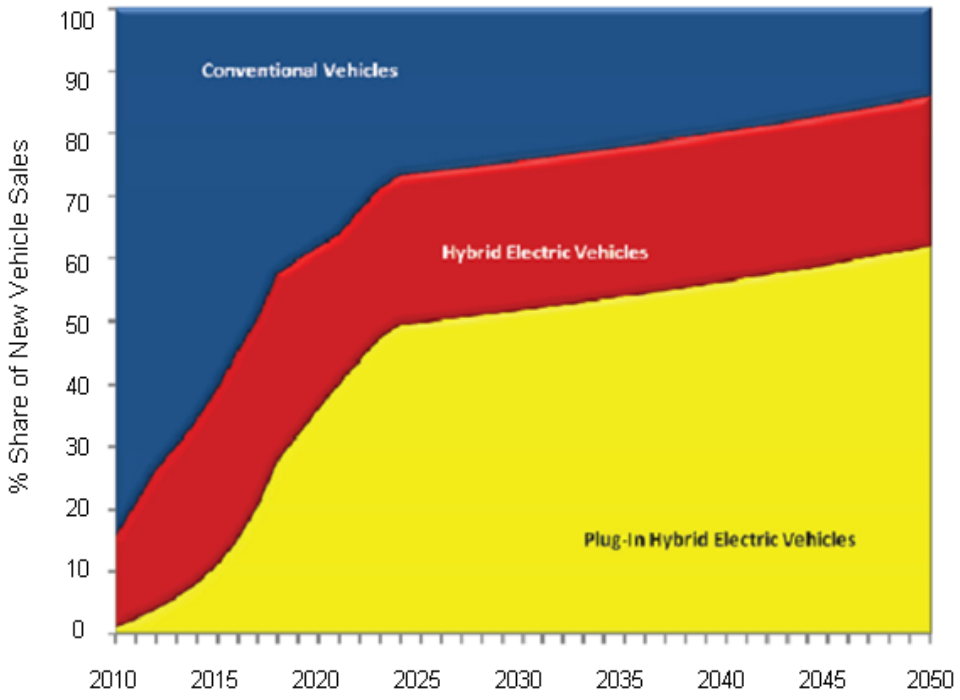
A.1.2 Vehicle Adoption Rate

To project the adoption of electric vehicles in Humboldt County, two primary literature sources were consulted. This included the *Environmental Assessment of Plug-In Hybrid Electric Vehicles* by EPRI and the Natural Resource Defense Council (EPRI/NRDC, 2007) as well as the *Long-Range EV Charging Infrastructure Plan for Western Oregon* by the Electric Transportation Engineering Corporation (ETEC, 2010). Integral to the EPRI/NRDC study was the development of market adoption scenarios, which estimate the new vehicle market share of plug-in hybrid electric vehicles from 2010 to 2050. Low, Medium, and High scenarios were developed and achieve a market share of 20 percent, 51 percent, and 68 percent, respectively, by 2030, and a maximum market share of 20 percent, 62 percent, and 80 percent, respectively, by 2050 (Figure 25). In comparison to other projections in the literature, EPRI's Medium and High plug-in hybrid electric vehicle scenarios are aggressive. The underlying assumptions for these projections are not specifically outlined, though they are intended to apply at the national level. As Humboldt County is a rather isolated rural area in Northwestern California, it is questionable how well these penetration rates may apply. State or regional market share projections may be more applicable.

The Electric Transportation Engineering Corporation study (ETEC, 2010) was also consulted. In August of 2009, ETEC was awarded a $99.8 million grant from the U.S. Department of Energy to partner with Nissan to deploy up to 4,700 battery electric vehicles (BEVs, for example, Nissan Leafs) and 11,210 charging systems in strategic markets in the states of Arizona, California, Oregon, Tennessee, and Washington (ETEC,

2010). The ETEC study presents various electric vehicle penetration projections for the U.S. and Western Oregon. Given Humboldt County's proximity and demographic similarities to the Corvallis-Albany region cited in the ETEC report, electric vehicle market share projections for the Corvallis-Albany area were assumed applicable and scaled to Humboldt County.

Figure 25: Assumed New Vehicle Market Share Under a Medium Plug-In Hybrid Electric Vehicle Scenario

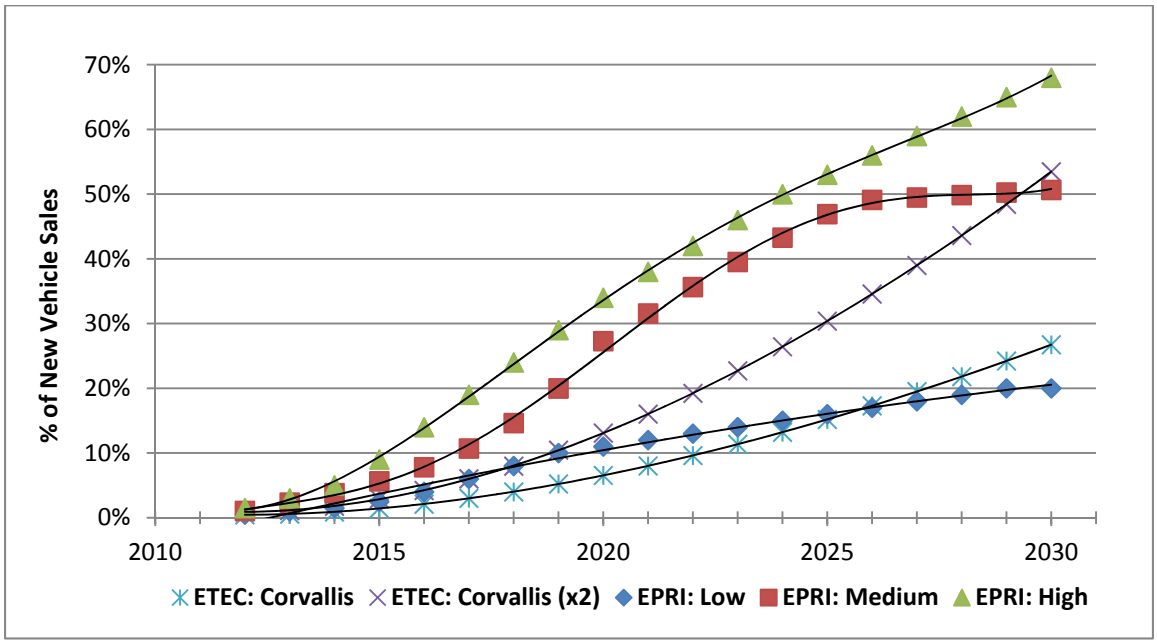


Source: EPRI (2007)

Figure 26 shows the projected electric vehicle market share for Corvallis-Albany in comparison to plug-in hybrid electric vehicles market share projected for the U.S. according to the aforementioned EPRI scenarios. The ETEC Corvallis scenario most closely follows the EPRI Low scenario. Doubling the Corvallis scenario penetration rates achieves a 2030 market penetration (53 percent) similar to that of the EPRI Medium scenario (51 percent), but is much slower in reaching that point. Figure 27 shows cumulative electric vehicles in Humboldt County according to the aforementioned electric vehicles market share projections. Three electric vehicle penetration scenarios were assumed for Humboldt County: (1) A likely (medium) scenario corresponding to expected electric vehicle diffusion in Corvallis-Albany; (2) an optimistic (high) scenario corresponding to a doubling of the expected penetration in Corvallis-Albany; and (3) a maximum scenario corresponding to the EPRI Medium scenario, meant to serve as a cap

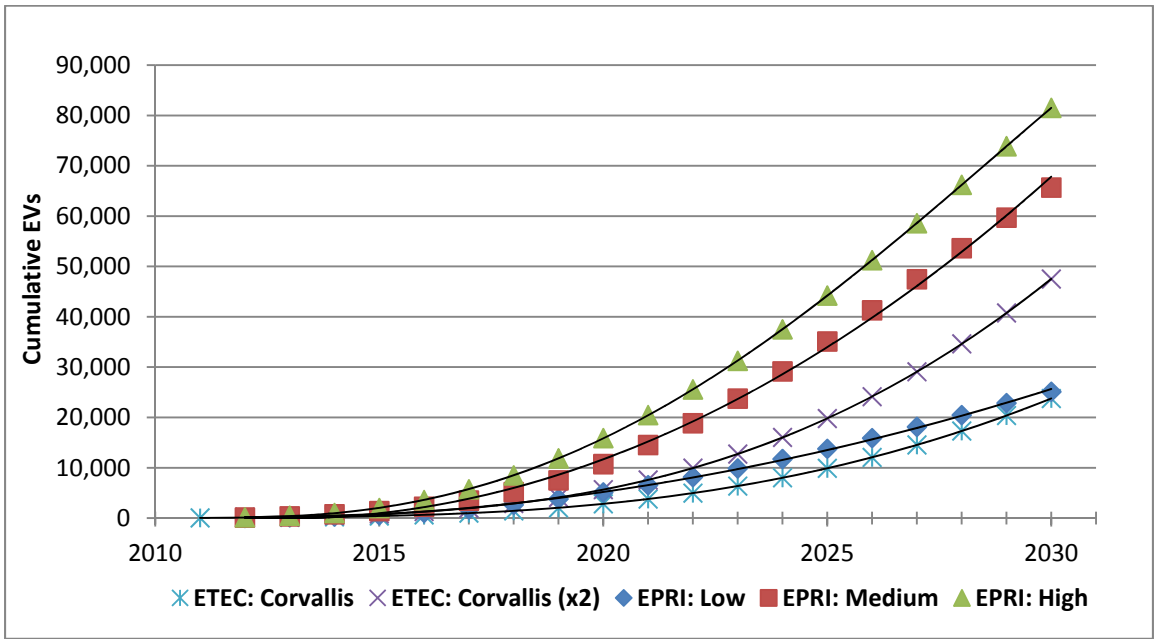
for electric vehicles penetration in the REPOP Model. This resulted in a cap on cumulative vehicle penetration in 2030 of 38 percent.

Figure 26: Assumed New Car Market Share in the United States for Low, Medium, and High Plug-in Hybrid Electric Vehicle Scenarios and Corvallis-Albany EV Scenario



Source: SERC compilation from EPRI (2007) and ETEC (2010)

Figure 27: Projected Cumulative EVs in Humboldt County Based on Low, Medium, and High Plug-in Hybrid Electric Vehicle Scenarios and a Corvallis-Albany EV Scenario



Source: SERC compilation from EPRI (2007) and ETEC (2010)

A.1.3 Vehicle Performance

Most assumptions about electric vehicle architecture, performance, energy consumption, and capital and maintenance costs were obtained from the literature source *Where Are the Market Niches for Electric Drive Vehicles* by Santini et al. (2010), as well as via personal communication with Bryan D. Jungers, Research Manager at E Source in Boulder, Colorado. Only five electric vehicles were considered for this analysis based on architectures that are representative of current or near market technologies (Table 15). Santini et al. (2010) used the Powertrain System Analysis Toolkit to model and evaluate the performance of nine electric vehicles spanning the major classes of electric drive vehicles, including the split parallel-and-series system used by Toyota and Ford, a series extended range electric vehicle (EREV) similar to the Chevrolet Volt, and a battery electric powertrain similar to the Nissan Leaf,, Table 16..

Table 15: Description of Conventional and Electric Vehicles Considered for Adoption

Vehicle	Description
Conventional	Conventional vehicle; standard mid-size sedan powered by an internal combustion engine (for example, Toyota Camry)
PHEV10	Plug-in hybrid electric vehicle with a power-split drivetrain and an all-electric range of 10 miles (for example, Toyota Plug-in Prius)
PHEV40	Plug-in hybrid electric vehicle with a series drivetrain and an all-electric range of 40 miles
EREV30	Extended range electric vehicle; a plug-in hybrid electric vehicle with a series powertrain and an all-electric range of 30 miles; EREVs and series PHEVs are virtually identical, except that an EREV has an over-sized electric motor and battery that enable aggressive acceleration without triggering an engine-on event
EREV40	Extended range electric vehicle; a plug-in hybrid electric vehicle with a series powertrain and an all-electric range of 40 miles (for example, the Chevrolet Volt was originally advertised as an EREV40, but is reportedly a PHEV40 with a power-split drivetrain)
BEV100	Battery electric vehicle with an all-electric range of 100 miles (for example, Nissan Leaf)

Source: SERC staff.

Table 16: Drivetrain Components of Vehicles Considered for Adoption

Component	Gross Vehicle Weight	ICE Power	MC Peak Power	MC Cont. Power	MC2/Gen Peak Power	MC2/Gen Cont. Power
Vehicle Name	**(kg)**	**(kW)**	**(kW)**	**(kW)**	**(kW)**	**(kW)**
Conventional	2111	135	0	0	2	2
PHEV10	2201	80	76	38	45	30
PHEV40	2321	70	108	54	68.25	68.25
EREV30	2325	75	109	54.5	73.2	73.2
EREV40	2355	75	109	54.5	73.2	73.2
BEV100	2185	0	103	51.5	0	0
Component	**BOL ESS Total Nominal Energy**	**EOL ESS Total Nominal Energy**	**BOL ESS Power-to-Energy Ratio**	**EOL ESS Power-to-Energy Ratio**	**Degree-of-Elec.**	**CD Useable Energy**
Vehicle Name	**(kWh)**	**(kWh)**	**(1/hr)**	**(1/hr)**	**(%)**	***(kWh)***
Conventional	0.0	0.0	0.0	0.0	0%	0.00
PHEV10	5.0	4.0	15.5	15.5	41%	2.30
PHEV40	16.9	13.5	4.4	4.4	44%	8.96
EREV30	12.4	9.9	15.4	15.4	59%	6.42
EREV40	16.3	13.1	12.1	12.1	59%	8.64
BEV100	33.2	26.6	5.8	8.3	100%	18.6

Component Definitions

ICE: internal combustion engine
MC: electric machine/motor
MC2: electric machine/motor #2
Gen: generator
BOL: beginning of life
EOL: end of life
ESS: energy storage system
CD: charge-depleting

Source: Santini et al. (2010)

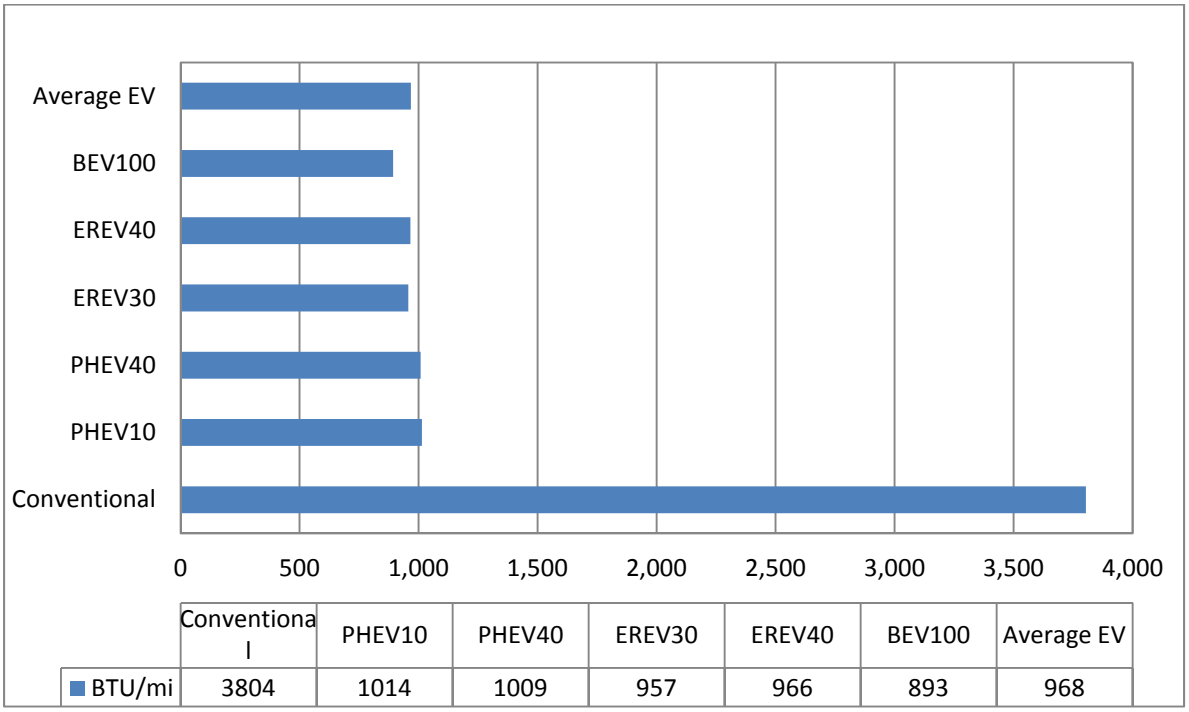
Vehicle fuel economy and electric efficiency are shown in Table 17 and include minor improvements in fuel economy expected to occur by 2020. Based on an estimated 60 percent highway and 40 percent city split in vehicle miles traveled in Humboldt County, Figure 28 compares the tank-to-wheel efficiency of electric vehicles in charge-depleting mode and a conventional vehicle. On average, a conventional vehicle requires about four times the energy as an electric vehicle on a per mile basis. This is reasonable since an electric motor is much more efficient than an ICE and highlights one of the major advantages of an EV. Assuming approximate current day gasoline and electricity costs ($4/gallon, $0.12/kWh) in Humboldt County, a conventional vehicle costs about 3.6 times as much to fuel as the average EV (Figure 29). Electric vehicles are clearly more efficient which results in less fuel consumption and fuel costs for vehicle owners.

Table 17: Fuel and Electric Efficiency of EVs Considered for Adoption in Humboldt County

	City		Highway	
Vehicle	**Fuel Economy: Charge-Sustaining mode (mpg)**	**Electric Efficiency: Charge-Depleting mode (Wh/mi)**	**Fuel Economy: Charge-Sustaining mode (mpg)**	**Electric Efficiency: Charge-Depleting mode (Wh/mi)**
Conventional	25.9		37.6	
PHEV10	57.2	229.0	56.1	226.2
PHEV40	48.4	227.3	50.9	225.5
EREV30	49.3	213.0	51.3	215.5
EREV40	51.6	217.5	52.6	215.9
BEV100		190.7		206.5

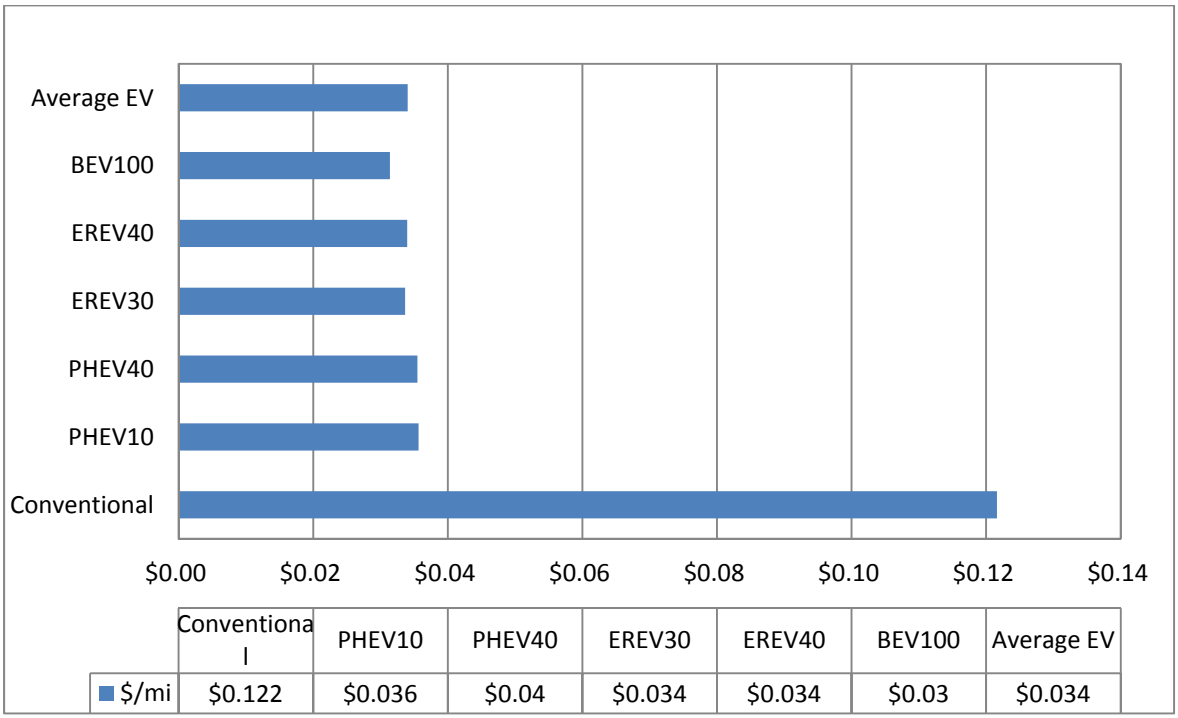
Source: Santini et al. (2010)

Figure 28: Tank-to-Wheel Efficiency (BTU/mi) of EVs in Charge-Depleting Mode Versus a Conventional Vehicle



Source: SERC staff analysis

Figure 29: Fuel Cost ($/mi) of Electric Vehicles in Charge-Depleting Mode Versus a Conventional Vehicle



	Conventional	PHEV10	PHEV40	EREV30	EREV40	BEV100	Average EV
$/mi	$0.122	$0.036	$0.04	$0.034	$0.034	$0.03	$0.034

Source: SERC staff analysis

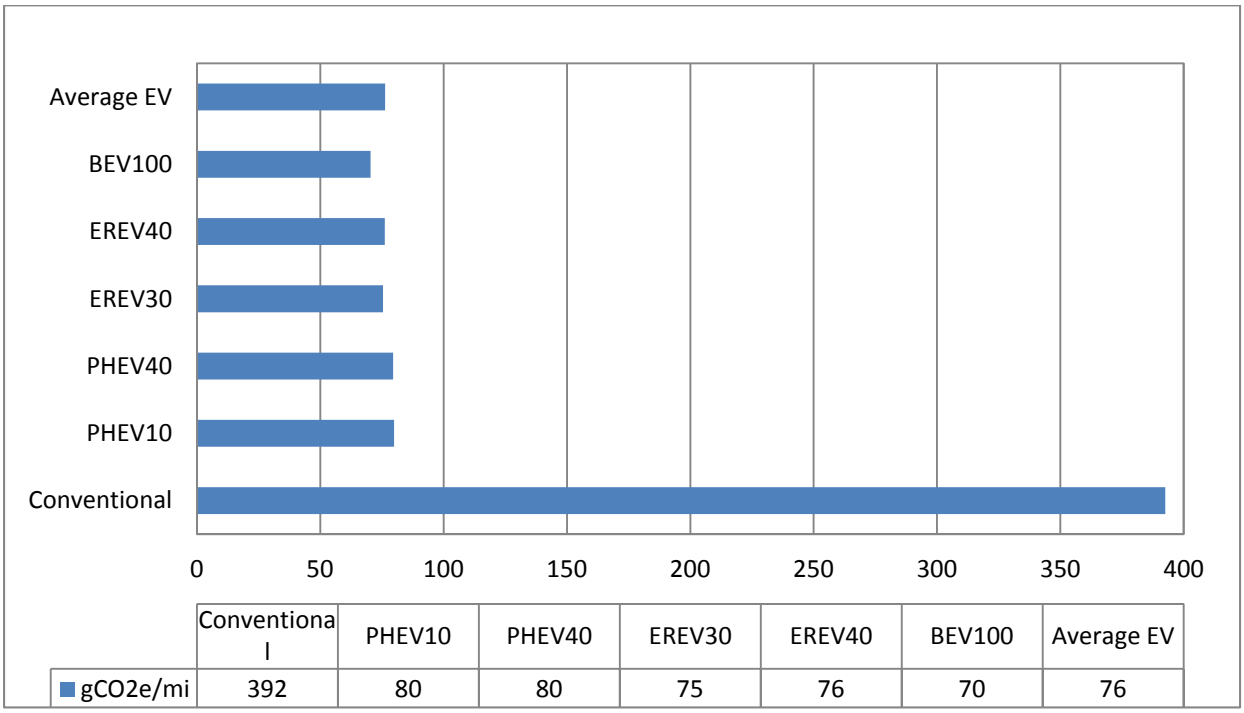
To estimate GHG emissions a gasoline well-to-wheel emission factor of 97.8 g/MJ was assumed (CARB, 2009). For electricity generation, several emission factors estimated by the REPOP model were used (Table 18). These are based on different scenarios of electricity generation mixes in Humboldt County. Assuming an emission factor of 0.269 tCO_2e/MWh (2010, Business-as-usual scenario) suggests that a conventional vehicle results in about five times the GHG emissions as the average electric vehicle does in charge-depleting mode (Figure 30). Emission factors for electricity generation are based on plant-to-wheel estimates, and not well-to-wheel.

Table 18: REPOP Estimated Retail Cost of Electricity and Power Plant Emissions Factor Based on Different Electricity Generation Scenarios in Humboldt County

Year	Generation Scenario	Generation Scenario Description	Retail Cost ($/MWh)	Generation Emissions (tCO_2e/MWh)
2010	Business-as-usual	• Natural Gas: 63.5% • Biomass: 31.6% • Hydroelectric: 4.8% • Photovoltaic: 0.1%	122.4	0.269
2010	Medium renewables penetration	• Wind: 50 MW • Wave: 15 MW • Biomass: +20 MW • Hydroelectric: +10 MW • PV: +0.5 MW • EV penetration: 20% • Heat Pump penetration: 20% • Efficiency penetration: 20%	123.5	0.152
2010	High renewables penetration	• Wind: 125 MW • Wave: 30 MW • Biomass: +70 MW • Hydroelectric: +13 MW • PV: +1 MW • EV penetration: 38% • Heat Pump penetration: 38% • Efficiency penetration: 100% • Storage: 15 MW	128.5	0.035
2020	Business-as-usual	Similar to 2010, Business-as-usual	121.6	0.275
2020	Medium renewables penetration	Similar to 2010, Medium renewables penetration	122.7	0.162
2020	High renewables penetration	Similar to 2010, High renewables penetration	128.0	0.043
2030	Business-as-usual	Similar to 2010, Business-as-usual	120.9	0.281
2030	Medium renewables penetration	Similar to 2010, Medium renewables penetration	123.3	0.178
2030	High renewables penetration	Similar to 2010, High renewables penetration	127.4	0.050

Source: SERC staff analysis

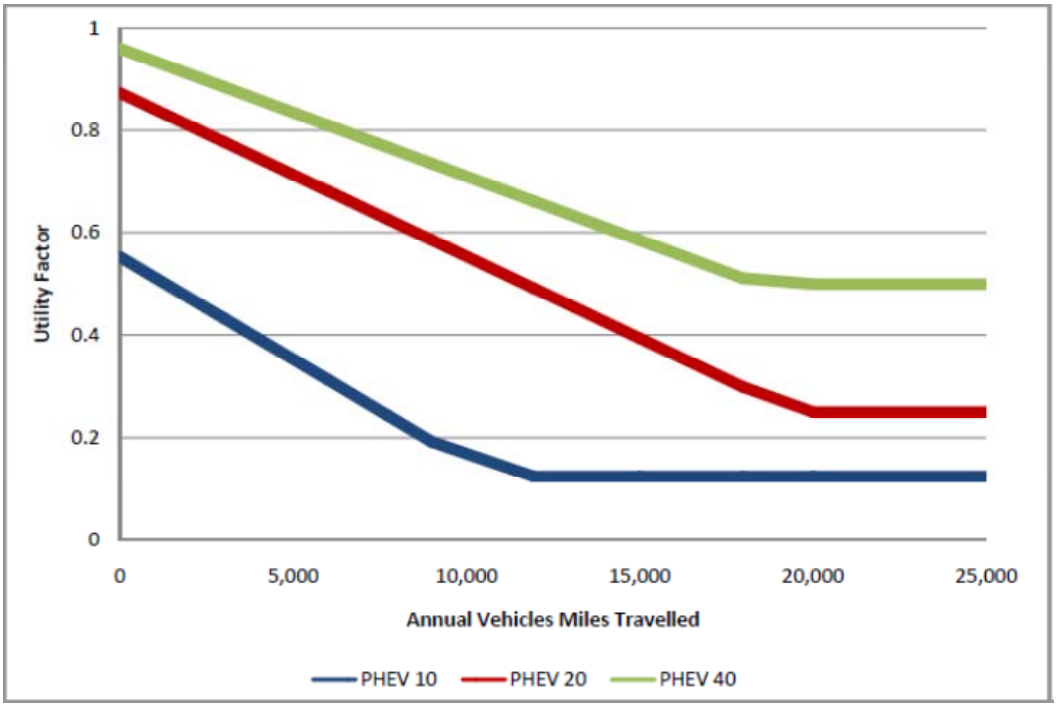
Figure 30: GHG Emissions (gCO_2e/mi) of EVs in Charge-Depleting Mode Versus a Conventional Vehicle



Source: SERC staff analysis

The Metropolitan Transportation Commission estimates that in 2008 annual vehicle miles traveled per capita in the North Coast region of California was about 10,500 miles. Based on California Department of Transportation and California Department of Motor Vehicles data from 1999 to 2007, average annual vehicle miles traveled per vehicle in Humboldt County was about 11,000 miles, or 30 miles per day, which was assumed for this analysis. National utility factors developed by EPRI were applied to determine the fraction of miles driven by plug-in hybrid electric vehicles that are derived from electricity (Figure 31). Utility factor is primarily dependent on annual vehicle miles traveled and all-electric range. In general, plug-in hybrid electric vehicles that are driven on many long trips, say beyond the 30-mile daily average in Humboldt County, will have lower utility factor. Other parameter assumptions that were used to estimate total energy use and costs use are included in Table 19 and Table 20.

Figure 31: Plug-In Hybrid Electric Vehicle Utility Factor as a Function of All-Electric Range and Annual Vehicle Miles Travelled, Assuming Nightly Charging



Source: EPRI (2007)

Table 19: Lifecycle Benefit / Cost Analysis Parameter Assumptions

Category	Parameter	Units	Value	Source
Battery	Battery Average Lifetime	yr	10	Santini et al., 2011
	Battery Efficiency (Round-trip)	%	90	Santini et al., 2011
	Battery Warranty	mi	100000	Chevrolet; Nissan, 2011
	Battery Warranty	yr	8	Chevrolet; Nissan, 2011
Charging	Charger Efficiency (Level 1)	%	95	Santini et al., 2011
	Charger Efficiency (Level 2)	%	85	Santini et al., 2011
	Charge Rate (Level 1) (110-120V, 15-20A)	kW	1.44	INL (DOE), 2008
	Charge Rate (Level 2) (240V, 40A)	kW	3.3	INL (DOE), 2008
	Charge Rate (Level 3) (480V, 80A)	kW	38.4	INL (DOE), 2008
	Charger Capital Cost (Level 2)	$	2272	Santini et al., 2010
	Vehicle Charges per day	charge/day	1	Santini et al., 2011
	Driving Days	day/yr	360	Santini et al., 2011
Discount Rate	Discount Rate	%	6.4	Santini et al., 2011
Emissions	Gasoline Well to Wheels CO2e	g/MJ	97.800	CARB, 2009
	Electricity Generation (BAS, 2010)	tCO_2e/MWh	0.26893	REPOP estimate, 2011
	Elec. Gen. (BAS, 2020)	tCO_2e/MWh	0.27518	REPOP estimate, 2011
	Elec. Gen. (BAS, 2030)	tCO_2e/MWh	0.28122	REPOP estimate, 2011
	Elec. Gen. (MRP, 2010)	tCO_2e/MWh	0.15208	REPOP estimate, 2011
	Elec. Gen. (MRP, 2020)	tCO_2e/MWh	0.16170	REPOP estimate, 2011
	Elec. Gen. (MRP, 2030)	tCO_2e/MWh	0.17768	REPOP estimate, 2011
	Elec. Gen. (HRP, 2010)	tCO_2e/MWh	0.03546	REPOP estimate, 2011
	Elec. Gen. (HRP, 2020)	tCO_2e/MWh	0.04258	REPOP estimate, 2011
	Elec. Gen. (HRP, 2030)	tCO_2e/MWh	0.05018	REPOP estimate, 2011
EVs	PHEV10 Weight	%	25	Santini et al., 2011
	PHEV40 Weight	%	13	Santini et al., 2011
	EREV30 Weight	%	13	Santini et al., 2011
	EREV40 Weight	%	25	Santini et al., 2011
	BEV100 Weight	%	25	Santini et al., 2011
	Utility Factor (PHEV10, 10k VMT)	%	16.67	EPRI, 2007
	Utility Factor (PHEV30, 10k VMT)	%	63.2	EPRI, 2007
	Utility Factor (PHEV40, 10k VMT)	%	71.11	EPRI, 2007

Parameter Definitions

BAU: business-as-usual
MRP: medium renewables penetration
HRP: high renewables penetration
VMT: vehicle miles traveled

Source: SERC staff analysis

Table 20: Lifecycle Cost / Benefit Analysis Parameter Assumptions

Category	Parameter	Units	Value	Source
EVs	BEV Maintenance Cost	$/mi	0.0077	EPRI, 2004
	PHEV Maintenance Cost	$/mi	0.02671	EPRI, 2004
	CV Maintenance Cost	$/mi	0.03598	EPRI, 2004
	CV Maintenance Cost	$/mi	0.0454	BTS, 2009
	Tire Maintenance Cost	$/mi	0.0083	BTS, 2009
	Vehicle Lifetime	year	17	CARB, 2009.
Fuel	Gasoline Price (2010-2030)	$/gal	4.00	Humboldt Economic Index, 2011
	Retail Electricity (BAU, 2010)	$/kWh	0.12240	REPOP estimate, 2011
	Retail Electricity (BAU, 2020)	$/kWh	0.12164	REPOP estimate, 2011
	Retail Electricity (BAU, 2030)	$/kWh	0.12092	REPOP estimate, 2011
	Retail Electricity (MRP, 2010)	$/kWh	0.12347	REPOP estimate, 2011
	Retail Electricity (MRP, 2020)	$/kWh	0.12274	REPOP estimate, 2011
	Retail Electricity (MRP, 2030)	$/kWh	0.12329	REPOP estimate, 2011
	Retail Electricity (HRP, 2010)	$/kWh	0.12853	REPOP estimate, 2011
	Retail Electricity (HRP, 2020)	$/kWh	0.12796	REPOP estimate, 2011
	Retail Electricity (HRP, 2030)	$/kWh	0.12737	REPOP estimate, 2011
Humboldt County	Driving Fraction (Freeway)	%	60	Estimated from CADOT, 2009
	Driving Fraction (City)	%	40	Estimated from CADOT, 2009
	Average Annual Miles Driven	mi/yr	11,000	Estimated from CADOT, 2009 and CADMV, 2008
	Average Daily Driving Distance	mi/day	30	Estimated from CADOT, 2009 and CADMV, 2008
	City Driving Schedule		UDDS	Santini et al., 2011
	Highway Driving Schedule		HWFET	Santini et al., 2011
	New Vehicle Sales (CA)	%	7.89	Estimated from CADMV, 2001-2007
	Fraction light duty trucks	%	56.7	Estimated from CADMV, 2001-2007
	Average Fuel Efficiency of CV	mi/gal	18	Estimated from CADOT, 2009 and CADMV, 2008
	Average Fuel Eff. of New CV (City)	mi/gal	25.9	BTS, 2009
	Average Fuel Eff. of New CV (Hwy)	mi/gal	37.6	BTS, 2009
Incentives	Federal Tax Credit (BEV)	$	7500	U.S. Department of Energy, 2010
	Federal Tax Credit (PHEV)	$	7500	U.S. Department of Energy, 2010

Parameter Definitions
BAU: business-as-usual
MRP: medium renewables penetration
HRP: high renewables penetration
CV: conventional vehicle

Source: SERC staff analysis

Table 21 shows estimated annual electricity and gasoline consumption, fuel costs, and emissions based on an annual vehicle miles traveled of 11,000 miles, a gasoline price of $4 per gallon, an electricity price of $0.12 per kWh, and emission factors corresponding to a 2010 business-as-usual generation mix. On average an EV reduces annual gasoline consumption by 256 gallons (78 percent), annual fuel cost by $792 (60 percent), and net emissions by 2.78 tCO_2e (66 percent). Combining the projected penetration rates previously discussed for Humboldt County with average electric vehicle energy demand leads to the county level estimates in

Table 22. It is assumed that each electric vehicle adopted in Humboldt County is purchased as a new vehicle and displaces the purchase of a new mid-sized conventional vehicle (for example a Toyota Camry), with its respective fuel economy. An electric vehicle is assumed to be retired from the county vehicle fleet after a lifetime of 17 years. An additional 15 MWh and 30 MWh of daily electricity would be demanded from the grid under Medium and High penetration scenarios, respectively, in 2020. This would increase substantially to 126 MWh and 252 MWh of daily electricity consumption in 2030. To simulate vehicle charging, Level 1 charging (1.44 kW charge rate) and power demand profiles similar to those developed in an NREL study (Figure 32), were assumed. The four EV charging profiles are intended to represent boundary cases and probable charging scenarios. These were scaled to fit projected EV energy demand in

Table 22.

Table 21: Estimated Vehicle Electricity and Gasoline Use and Associated Cost, and CO_2e Emissions

	Electricity Use				Gasoline Use			
Vehicle	**kWh/day**	**kWh/year**	**$/year**	**tCO_2e/year**	**gal/day**	**gal/year**	**$/year**	**tCO_2e/year**
Conventional	0.00	0	0	0.00	0.91	328	$1,313	4.24
PHEV10	1.49	535	$65	0.15	0.44	159	$637	2.06
PHEV40	6.31	2271	$276	0.62	0.17	62	$250	0.81
EREV30	5.32	1914	$233	0.53	0.22	79	$315	1.02
EREV40	6.04	2174	$264	0.60	0.17	60	$239	0.77
BEV100	7.85	2826	$344	0.78	0.00	0	$0	0.00
Average EV	5.30	1907	$232	0.52	0.20	72	$290	0.93

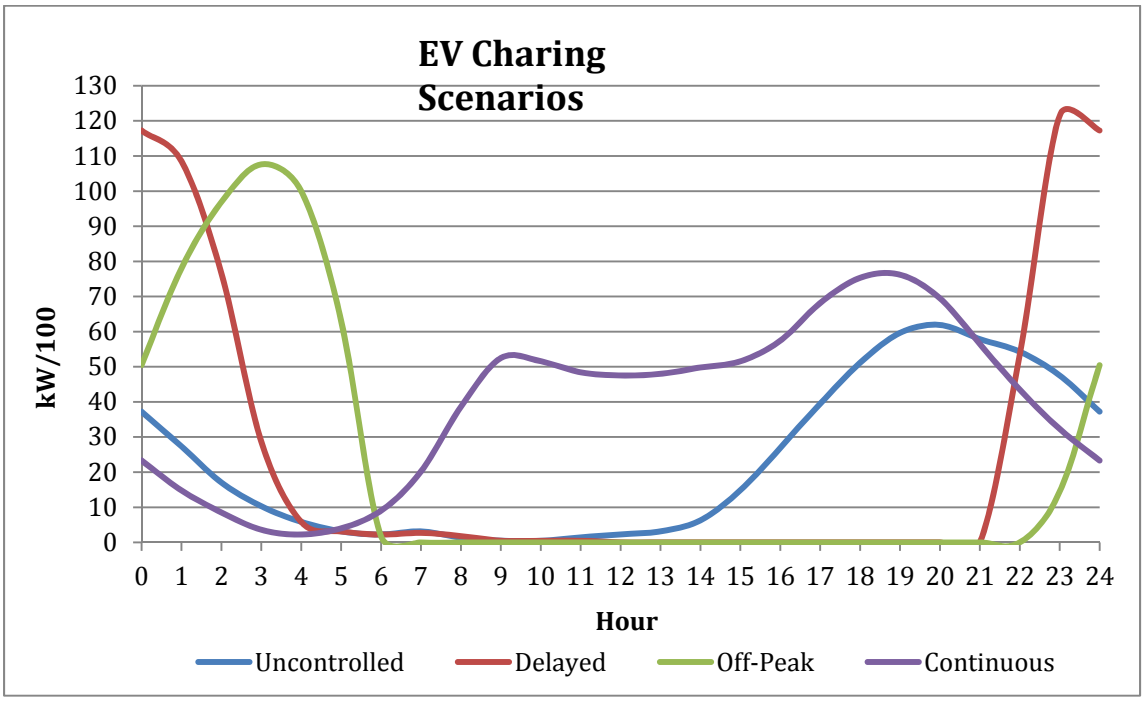
Source: SERC staff analysis

Table 22: Estimated Cumulative Electric Vehicles in Humboldt County in 2020 and 2030 and Associated Daily Electricity and Gasoline Demand, Under Medium, High, and Max Penetration Scenarios

	Projected Cumulative EVs in Humboldt County			Projected Daily EV Energy Consumption (MWh)			Projected Daily EV Gas Consumption (gal)		
Scenario	**Medium**	**High**	**Max**	**Medium**	**High**	**Max**	**Medium**	**High**	**Max**
2020	2,833	5,666	10,731	15	30	57	570	1,139	2,158
2030	23,758	47,516	65,670	126	252	348	4,778	9,555	13,206

Source: SERC staff analysis

Figure 32: Four Vehicle Charging Scenarios Developed by NREL to Evaluate PHEV-Charging Impacts on the Utility System Operations Within the Xcel Energy Colorado Service Territory



Source: NREL (2007)

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APPENDIX B: Alternative Transportation Fuel Pathways

B.1 Hydrogen Transit Assessment

There are several hydrogen transit demonstration projects in the US and throughout the world. The National Renewable Energy Laboratory (NREL) has evaluated fuel cell bus demonstration projects funded by the Department of Transportation's Federal Transit Administration (FTA) since 2000. NREL evaluates the buses, hydrogen infrastructure and the transit authority's experience in implementing the program. One of the projects currently under evaluation is the Zero Emission Bay Area demonstration, which will include twelve next-generation Van Hool chassis buses with UTC Power fuel cells and hybrid propulsion systems. This demonstration will be led by AC Transit and will also include other transit agencies in the area such as Santa Clara VTA, Sam Trans, Golden Gate Transit, and San Francisco Municipal Transportation Agency. The project includes the construction of a new fueling station. Some of the hydrogen will be generated onsite using renewable electricity, and the balance of the hydrogen will be trucked in as a liquid. This project is currently the largest in the US (Eudy, Chandler & Gikakis, 2010).

The FTA is also overseeing the National Fuel Cell Bus Program, which will provide $49 million in cost share for developing and demonstrating new transit buses. The funds will be provided for eleven buses. The program will expand the number of fuel cell power system manufacturers under evaluation and will demonstrate buses of different sizes and different hybrid propulsion designs. It will ideally be a final step before the introduction of commercial fuel cell buses into transit in the US. The buses will be located mostly on the East Coast, with four going to Connecticut, three to New York, and one each to Massachusetts and South Carolina. The final two will be in California, one each in San Francisco and Palm Desert (Eudy, et al., 2010).

The largest fleet of fuel cell buses in the world is located in British Columbia, Canada. The fleet of 20 buses was introduced for the 2010 Winter Olympic Games in Whistler. The buses are from New Flyer and use Ballard fuel cells; the hybrid propulsion systems are from ISE/Siemens. The fueling station built to serve this fleet is the largest of any transit system.

Transit systems and vehicle fleets are an ideal place for the introduction to hydrogen fuel cell vehicles because of the central fueling and maintenance infrastructure. They also expose a large number of people to the technology that would otherwise not have access to it and offer many opportunities for public outreach. Switching to fuel cell buses

also has positive impacts on local air quality. The only emission from a fuel cell bus is water vapor, completely eliminating the particulates and smells associated with diesel buses. Fuel cell buses are also much quieter than conventional diesel buses.

B.1.1 Hydrogen Fuel Cell Bus Analysis Methodology

Mass transit makes up a small percentage of Humboldt County's overall transportation energy consumption, accounting for only 1.5 percent of diesel fuel consumed in the county annually. Humboldt County uses approximately 195,000 gallons of diesel a year to fuel its three transit systems. Redwood Transit System is the largest system in the county. It operates Monday thru Saturday from Scotia in the south to Trinidad in the north, with weekday service to Willow Creek. Within the south county it operates from Garberville to Myers Flat. Eureka Transit System serves the city of Eureka and the Arcata and Mad River Transit System serves the city of Arcata. Annually the three systems travel approximately 1,250,000 miles and have a ridership of over one million passengers. Greenhouse gas emissions associated with diesel fuel use are approximately 433,000 pounds of CO_2 equivalent annually. The purpose of this analysis was to investigate the cost of a hydrogen-based transit system in Humboldt County and the greenhouse gas emission impacts.

Currently there are several ways to generate hydrogen. The most common method is steam reformation of methane (the main component of natural gas). Hydrogen can also be generated from water via electrolysis. Electrolysis uses electricity to split water into hydrogen and oxygen. If the electricity used for electrolysis is renewable, the hydrogen fuel can be considered a renewable fuel. Generating hydrogen with renewable energy is a way of storing renewable energy and is particularly useful if surplus renewable energy is available. For this analysis only hydrogen generated via electrolysis was considered, as generating hydrogen from fossil fuels does not satisfy the goals of the RESCO project.

This analysis used a Microsoft Excel® model to generate the desired outputs. The user can define the following inputs to the model:

- Total transit miles travelled annually in Humboldt County (1,250,000)
- Fuel economy for the fuel cell buses (7.77 miles/kg)
- Fuel economy for diesel buses (6.41 miles/gallon)
- Price of diesel ($3.5/gallon)
- Price of electricity ($0.124/kWh)
- Carbon intensity of electricity (0.304lbs/kWh)
- Energy intensity to generate and compress hydrogen (60 kWh/kg)
- Operations and maintenance costs for diesel buses ($4.03/mile includes labor costs)
- Operations and maintenance costs for fuel cell buses ($4.43/mile includes labor costs)

Most of the variables were held constant for the analysis, though several were changed for a sensitivity analysis as discussed below.

The number of miles traveled by the fuel cell buses and the fuel efficiency of the buses was used to determine the hydrogen generation requirements. The fueling station was sized to meet the maximum daily hydrogen requirements plus an additional 20 percent. Various levels of hydrogen bus penetration were considered, from a small hydrogen system covering 10 percent of the total miles traveled to full-scale hydrogen system covering 100 percent of the miles traveled.

Costs associated with a hydrogen transit system include: upfront costs for building a fueling station and purchasing buses, ongoing operations and maintenance costs for the fueling station and hydrogen buses, and electricity costs associated with generating and compressing hydrogen. Costs associated with building, operating and maintaining the fueling station came from a California Hydrogen Highway economic report (Economy Topic Team, 2005). The costs for operations and maintenance of the fuel cell buses were based on reports by AC Transit for their fuel cell bus pilot program and were adjusted down to account for the learning curve that will likely cause costs to decrease as the technology matures and becomes more reliable. The cost used for the fuel cell buses, $750,000, is a number estimated by AC Transit to be the cost ceiling necessary for commercialization of fuel cell buses. Current fuel cell bus costs are closer to $2 million. The cost of electricity used in the analysis is based on a likely 2030 scenario as determined using the REPOP model.

Costs for the current diesel bus system were based on data provided by Humboldt Transit Authority and A&MRTS. The cost of diesel fuel was assumed to be the same as the current cost. A sensitivity analysis on fuel costs is included to address how this assumption affects the final results.

The amount of carbon dioxide offset by the hydrogen system is the amount of carbon dioxide that would have been produced by the offset diesel fuel, minus the amount of carbon dioxide produced while generating electricity to produce hydrogen. The cost for the offset carbon dioxide is the difference in cost between BAU and the hydrogen scenario.

B.2 Forest-Based Biofuels Assessment

An assessment was conducted to determine which forest-based biofuel pathways are closest to commercialization. It was determined that the Fischer-Tropsch biodiesel pathway and the cellulosic ethanol pathway are most likely to be successful. Each of these pathways is described below.

B.2.1 Fischer-Tropsch Biodiesel

For lignocellulosic feedstocks, gasification is generally considered to be the most convenient conversion method because of its applicability to both electricity and liquid fuel production. Gasification is a general term used to describe gaseous fuel production

by partial oxidation of a solid fuel (NTNU, 2005). The product of biomass gasification is synthesis gas (syngas), consisting primarily of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2) and methane (CH_4). The thermochemical conversion is carried out under high temperatures (1,500°F to 2,000°F) with a controlled amount of oxygen and/or steam. Syngas can serve as a feedstock for catalytic synthesis into liquid fuels (for example, ethanol, gasoline, diesel) or be used as a substitute for natural gas in cogeneration engines, turbines and boilers to produce electricity and/or heat.

Gas-to-liquids is a refinery process used to convert gaseous hydrocarbons into longer-chain hydrocarbons, such as automotive fuel. This can be accomplished by either bacterial fermentation or, more commonly, catalytic synthesis. Catalytic synthesis is most often carried out through the Fischer-Tropsch process, which is capable of synthesizing a number of automotive fuels. Though ethanol production is possible through Fischer-Tropsch, the process is usually applied to diesel fuel production. The Fischer-Tropsch process is widely considered to be the most promising technology available today for woody biomass gas-to-liquids fuel production (NTNU, 2005).

Fischer-Tropsch synthesis is a carbon chain building process whereby CH_2 groups are attached to the ends of carbon chains. The exact sequence and behavior of the chemical reactions that take place have been subject to controversy since the 1930's (NTNU, 2005), but can generally be described by the overall equation:

$$nCO + \left(n + \frac{m}{2}\right) H_2 \rightarrow C_n H_m + nH_2O$$

The reactions are highly exothermic and require sufficient cooling to maintain stable reaction conditions. Overheating results in undesirably high yields of methane production and an increased rate of catalyst deactivation due to sintering and fouling (Dry, 2002). A number of catalysts can be used, but most commonly transition metals such as cobalt, iron or ruthenium are used.

A wide range of products result from the Fischer-Tropsch reaction, including olefins, paraffins, and oxygenated products (alcohols, aldehydes, acids and ketones). Fischer-Tropsch synthesis invariably produces a small portion of methane, which is usually reformed with steam into H_2 and CO, and fed back into the reactor. The fuel produced directly out of the Fischer-Tropsch reactor is termed straight-run to distinguish itself from the fuel produced after synthesis from upgraded hydrocarbons. The output of desired products can be greatly increased by selecting an appropriate reactor type, catalyst, pressure range and temperature mode. Fischer-Tropsch reactions are classified into two modes: low and high temperature which take place at temperature ranges of 200-240°C (392-482°F) and 300-350°C (572-662°F), respectively (Dry, 2002).

Fischer-Tropsch diesel synthesis works best with a high capacity low temperature slurry bed reactor and a cobalt or iron catalyst. Along with producing about 20 percent straight-run diesel, this reaction produces excess paraffin wax, which is usually hydrocracked and fed back into the reactor until extinction. The straight-run diesel has a cetane number of 75 to 80 whereas diesel hydrocracked from wax has a cetane number

of 70 to 75 (Leckel, 2009). The resulting mixture of straight-run and hydrocracked diesel is a fuel with cetane number of about 70. Compared to conventional petro-diesel, which is required to have cetane of 45 or higher, Fischer-Tropsch diesel is of higher quality, lower aromatic content and free of sulfur. This allows Fischer-Tropsch diesel to be used as a blending stock to upgrade lower quality fuels (Dry, 2002).

B.2.2 Cellulosic Ethanol

The biochemical approach is most often utilized for bioethanol production through hydrolysis and subsequent fermentation. While being slower than a chemical reaction, the biological process has several advantages, including higher specificity, higher yields, lower energy costs and greater resistance to catalytic poisoning (NTNU, 2005). Ethanol must be blended with other fuels when used as a transportation fuel. It has a high octane number and is commonly used as a petro-fuel additive to improve engine performance and emissions (NTNU, 2005). Most gasoline is blended with five to ten percent ethanol, but with minor engine modifications (for example, Flex Fuel Vehicles), blends of up to 85 percent can be utilized.

The fermentation of glucose (C6 sugar) is a well-known process and has been practiced for at least 6,000 years, beginning with early beer-making societies such as the Sumerians, Egyptians and Babylonians (NTNU, 2005). Most of the ethanol produced today (approximately 90 percent), as was the case in ancient times, comes from sugar and starch crops. These crops have high food value and low sugar yield per acre compared to cellulose and hemi-cellulose contained in lignocellulosic biomass, which is the most prevalent form of sugar in nature (NTNU, 2005). Unlike sugar and starch crops, which contain C6 sugars that are 100 percent convertible by normal yeasts, lignocellulosic biomass contains the C5 sugars xylose and arabinose as well as the C6 sugars glucose, galactose and mannose. It is estimated that 40 percent of sugars contained in lignocellulosic biomass cannot be metabolized by yeast. This 40 percent disadvantage largely contributes to why lignocellulosic feedstocks remain far from being competitive with starch and sugar crops for ethanol production (NTNU, 2005).

A pretreatment step prior to hydrolysis is required to remove lignin content and hydrolyze hemicellulose. The cellulose remaining after pretreatment can then be hydrolyzed into fermentable sugars (that is, glucose). Hydrolysis is a chemical reaction used to break down polymers, during which water molecules are split into hydrogen cations and hydroxide anions. In the case of cellulose hydrolysis, the following reaction takes place:

$$(C_6H_{10}O_5)_n + nH_2O \rightarrow nC_6H_{12}O_6$$

This reaction is traditionally catalyzed by sulfuric acid (either concentrated or dilute), but recent developments favor enzymatic hydrolysis using cellulase. Cellulase is a class of enzymes that catalyze cellulose hydrolysis and offers many advantages over acid hydrolysis, including lower maintenance costs, high yields and no corrosion issues.

Projected costs for enzymatic hydrolysis are estimated to be four times lower than concentrated acid hydrolysis, and three times lower than dilute acid hydrolysis (TSS Consultants, 2010). These developments, along with lower maintenance costs, no corrosion, and a lower environmental impact contribute to the belief among many experts that enzymatic hydrolysis is the most cost-effective method for producing ethanol in the long term (NTNU, 2005). The production cost of ethanol utilizing enzymatic hydrolysis is currently estimated at $2.24 per gallon for a 2,200 Bone Dry Ton (BDT) per day plant (NTNU, 2005).

A variety of microorganisms are capable of fermenting carbohydrates into ethanol under oxygen-free conditions, including bacteria, yeasts, and fungi. The reactions that take place are the following (Hamelinck, 2004):

$$3C_5H_{10}O_5 \rightarrow 5C_2H_5OH + 5CO_2$$

$$C_6H_{12}O_6 \rightarrow 2C_2H_5OH + 2CO_2$$

Fermentation of hexose sugars in lignocellulosic crops only became possible during the late 1800's. Pentose sugars, which represent the majority of available sugar in lignocellulosic crops, were not capable of being fermented until the 1980's, when a number of wild yeasts were discovered that were able to convert xylose to ethanol (Hamelinck, 2004). While bacteria are capable of faster fermentation than yeasts (minutes compared to hours), all microorganisms have their limitations, including at least one of the following: inability to process both pentoses and hexoses, low ethanol yields, co-production of cell mass at the expense of ethanol, and/or slow extermination of the microorganism population by oxygen free conditions (Hamelinck, 2004). Current fermentation configurations include separate reactors for glucose and xylose fermentations, since different microorganisms are needed to process the different sugars. Genetic engineering is expected to develop bacteria and yeasts that are capable of fermenting both xylose and glucose, and could have the potential to utilize the remaining sugars (mannose, galactose, arabinose) (Hamelinck, 2004).

B.2.3 Parameter Values and Results

This section contains inputs and results related to the forest-based biofuels assessment discussed in Section 2.3.2.3. Table 23 contains customized, non-default parameters used in the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Original equipment manufacturer plug-in hybrid electric vehicle and battery-electric vehicle plans between 2010 and 2012 are listed in Table 24. According to original equipment manufacturer plans, 8 plug-in hybrid electric vehicle models and 17 battery-electric vehicle models are planned for market introduction by 2012.

Table 25 contains well-to-wheel energy and emission changes for several alternative fuel pathways relative to a baseline of conventional vehicles fueled with conventional gasoline. Metrics included in this comparison are fossil fuels, GHGs, and criteria pollutants. Battery-electric vehicles have the largest impact, reducing fossil fuel use and

GHGs by 95 percent and 92 percent, respectively, followed by the Fischer-Tropsch Diesel (FTD) pathway, which results in reductions of 92 percent and 91 percent.

Similarly, Table 26 reports well-to-pump energy and emission changes for the same fuel pathways relative to the same baseline. On a well-to-pump basis the Fischer-Tropsch Diesel and Ethanol (via fermentation) pathways have the largest GHG impact, reducing emissions by 447 percent and 357 percent, respectively.

Table 23: GREET Fuel Pathway Parameters Customized to Humboldt County.

Category	Parameter	Value	Source
Simulation	Target year for simulation	2020	Maximum allowed
	Simulation vehicle types	Passenger Cars	
Fischer-Tropsch Diesel (FTD)	Classification of biomass for FTD	Forest Residue: 100%	
	Mass-based share of coal and biomass co-feeding to FTD production	Biomass: 100%, Coal: 0%	
Ethanol	Technologies for biomass-based ethanol plant	Forest Residue: Gasification and Fermentation	
	Ethanol Yield (gallons per dry ton)	Fermentation: 59 gal	TSS Consultants, 2010
	Electricity co-produced for export (kWh per gallon of ethanol)	Fermentation: -3.475	TSS Consultants, 2010
Electricity Generation	Mix for transportation use (user defined)	Biomass: 100%	
	Mix for stationary use (user defined)	Natural Gas: 63.5%, Biomass: 31.6%, Others: 4.9%	Estimated generation mix for Humboldt County
	Shares of technologies for other power plants (stationary use)	Hydroelectric: 97.5%, Solar PV: 2.5%	Estimated generation mix for Humboldt County
	Share of feedstock for biomass power plants	Forest Residue: 100%	

Source: SERC staff analysis

Table 24: Automotive Manufacturer Plans for Plug-In Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs)

Make	Model	All Electric Range (mi)	Battery Size (kWh)	U.S. Target Intro. Date
Plug In Hybrid Electric Vehicles				
Audi	A1 Sportback	31-62		2011
BYD Auto	F3DM	60		2010
Fisker	Karma	50		2010
Ford	Escape	40	10	2012
General Motors	Chevrolet Volt	40	16	2010
Hyundai	Blue-Will	38		2012
Toyota	Prius Plug-in	12.4-18.6		2012
Volvo	V70	31		2012
Battery Electric Vehicles				
BMW	ActiveE	100		2011
BYD Auto	e6	205		2010
Chrysler/Fiat	Fiat 500	100		2012
Coda Automotive	Coda Sedan	90-120		2010
Daimler	Smart ED	72-90		2012
	Mercedes Benz	120	35	2010 low volume
Ford	Focus	100		2011
	Transit Connect	100		2010
	Tourneo Connect	100	21	2011
Hyundai	i10 Electric	100	16	2012
Mitsubishi	iMiEV	100	16	2010
Nissan	LEAF	100	24	2010
Rolls Royce	Electric Phantom			2010
SAIC	Roewe 750	125		2012
Tesla Motors	Roadster	220	56	For sale now
	Model S	160, 230, 300		2011
Th!nk	City	113		2010

Source: ETEC (2010)

Table 25: Wells-to-Wheels Energy (BTU/mi) and Emission (g/mi) Changes for Several Fuel Pathways

Metric	Baseline: CG and RFG (BTU/mi or g/m)	EtOH FFV: E85, Biomass (gasification)	EtOH FFV: E85, Biomass (fermentation)	CIDI Vehicle: FT100, Biomass	SI PHEV: CG and Electricity, Biomass	BEV: Electricity, Biomass
Total Energy	5,279	24.2%	83.4%	39.5%	-11.8%	-15.1%
Fossil Fuels	4,909	-63.5%	-78.6%	-91.9%	-47.2%	-95.4%
Coal	28	-73.8%	-73.9%	-100.0%	-49.2%	-100.0%
Natural Gas	537	-41.9%	-211.7%	-92.1%	-47.3%	-95.6%
Petroleum	4,345	-66.1%	-62.2%	-91.8%	-47.1%	-95.3%
CO2 (w/ C in VOC & CO)	387	-64.7%	-75.4%	-91.8%	-47.6%	-95.2%
CH4	0.484	-60.0%	-86.4%	-91.7%	-46.3%	-92.3%
N2O	0.020	26.3%	145.3%	-34.0%	61.1%	137.1%
GHGs	405	-63.2%	-72.5%	-91.0%	-46.0%	-91.7%
VOC: Total	0.265	-17.6%	3.3%	-72.4%	-48.7%	-89.4%
CO: Total	3.540	-22.9%	-18.3%	-91.8%	-35.0%	-90.3%
NOx: Total	0.253	14.3%	99.6%	-31.5%	38.9%	100.0%
PM10: Total	0.054	-3.0%	111.6%	-36.2%	17.4%	43.4%
PM2.5: Total	0.030	-2.2%	60.7%	-39.8%	8.7%	23.1%
SOx: Total	0.086	-54.9%	-51.6%	-65.5%	-38.2%	-74.9%
VOC: Urban	0.158	-18.1%	-18.2%	-74.2%	-53.4%	-99.7%
CO: Urban	2.178	-25.2%	-25.5%	-92.7%	-39.2%	-100.0%
NOx: Urban	0.071	-34.3%	-59.8%	-34.0%	-48.2%	-98.3%
PM10: Urban	0.023	-15.8%	-20.0%	-32.3%	-19.8%	-44.5%
PM2.5: Urban	0.013	-17.4%	-26.0%	-42.1%	-27.2%	-62.8%
SOx: Urban	0.022	-65.0%	-62.4%	-90.8%	-47.6%	-96.4%

(percent change is relative to a baseline of conventional vehicles fueled with conventional and reformulated gasoline)

Source: SERC staff analysis

Table 26: Well-to-Pump Energy (BTU/mmBTU) and Emission (g/mmBTU) Changes for Several Pathways

Metric	Baseline: CG and RFG (BTU/mmBTU or g/mmBTU)	EtOH FFV: E85, Biomass (gasification)	EtOH FFV: E85, Biomass (fermentation)	CIDI Vehicle: FT100, Biomass	SI PHEV: CG and Electricity, Biomass	BEV: Electricity, Biomass
Total Energy	264,241	115.8%	399.2%	322.7%	178.9%	859.8%
WTP Efficiency	79.1%	63.7%	43.1%	47.2%	57.6%	28.3%
Fossil Fuels	217,596	-22.9%	-104.9%	-47.5%	-8.6%	-41.2%
Coal	6,650	-73.8%	-73.9%	-100.0%	-20.8%	-100.0%
Natural Gas	128,522	-41.9%	-211.7%	-90.5%	-18.7%	-89.7%
Petroleum	82,424	10.6%	59.2%	23.9%	8.2%	39.2%
CO2 (w/ C in VOC & CO)	15,895	-368.7%	-430.8%	-523.0%	-1.7%	-8.2%
CH4	113.413	-61.3%	-88.3%	-90.5%	-15.4%	-74.0%
N2O	1.889	66.3%	366.3%	-82.8%	388.9%	1868.8%
GHGs	19,293	-310.9%	-357.2%	-446.6%	7.7%	36.9%
VOC: Total	27.358	-8.7%	39.8%	-86.1%	-4.0%	-19.0%
CO: Total	13.806	103.1%	386.9%	-21.1%	387.0%	1859.4%
NOx: Total	44.051	27.1%	144.5%	-31.8%	167.7%	805.8%
PM10: Total	6.077	-6.4%	237.4%	-53.9%	132.9%	638.5%
PM2.5: Total	3.617	-4.3%	120.2%	-46.0%	113.1%	543.5%
SOx: Total	19.216	-53.7%	-50.2%	-55.9%	-2.5%	-12.0%
VOC: Urban	15.434	-9.1%	-9.3%	-93.3%	-20.3%	-97.3%
CO: Urban	2.909	-60.0%	-108.0%	-85.3%	-17.7%	-85.2%
NOx: Urban	6.697	-56.2%	-120.8%	-82.8%	-17.8%	-85.5%
PM10: Urban	1.350	-65.6%	-83.2%	-89.2%	-17.9%	-85.9%
PM2.5: Urban	0.810	-64.7%	-96.7%	-88.6%	-17.9%	-85.9%
SOx: Urban	4.494	-63.4%	-60.4%	-87.0%	-17.9%	-86.0%

(percent change is relative to a baseline of conventional and reformulated gasoline)

Source: SERC staff analysis

B.3 References

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APPENDIX C:
Energy Efficiency Analysis

This appendix provides a detailed description of the methodology used to carry out the energy efficiency analysis in the REPOP model. Potential energy savings were based on results of a statewide efficiency study conducted by Itron (2008). The Itron estimates were adapted to apply to Humboldt County as described below.

C.1 Methodology

The Itron (2008) study quantifies yearly (2007-2026) energy savings potential and associated costs by investor owned utility (IOU) service territory, Energy Commission climate zone (CZ), consumption sector, building type, end-use category, fuel type (electricity or natural gas), and efficiency measure type. The sectors and end-use categories included in the analysis are provided in the main body of the report in Table 1. Each end-use category is comprised of a number of efficiency measures that provide energy savings above a common base technology. Associated building types are listed in Table 27 below.

Table 27: Building Types by Sector

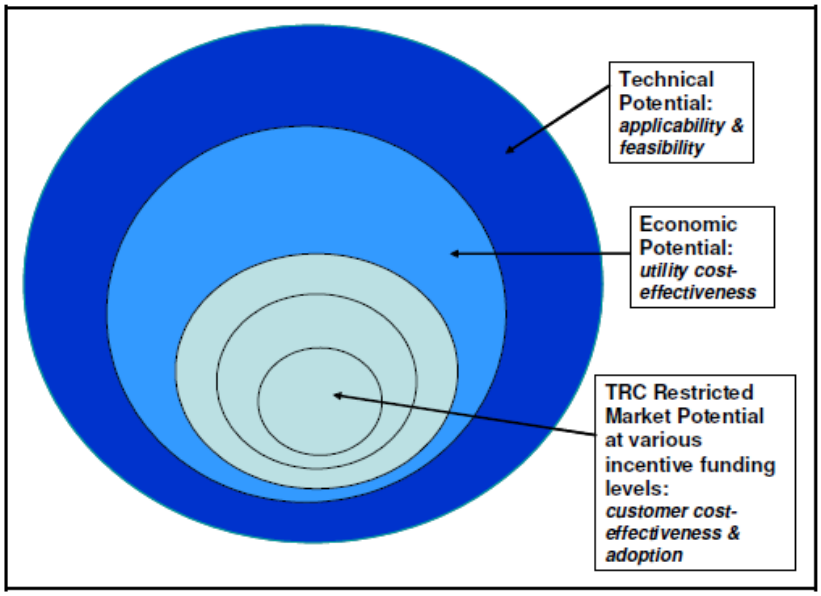
	Sector	
	Residential	**Commercial**
Building Type	Single Family Multi-Family Mobile Home	Colleges Grocery Stores Health Lodging Large Office Small Office Refrigerated Retail Restaurants Schools Warehouses Miscellaneous

Source: Schatz Energy Research Center staff.

For each of the individual measures, three categories of savings potential are quantified: technical, economic, and market potential (Figure 33). Technical potential is the highest level of savings and refers to the savings that would be realized if all applicable and feasible measures were actually installed. Economic potential is a subset of technical potential that limits the applicable and feasible measures to those that are cost-effective. Cost-effectiveness is determined using a total resource cost test, which is a ratio of avoided costs to incremental measure costs (neglecting programmatic costs). A measure with a total resource cost greater than one would be considered cost-effective. Market

potential is a further subset that takes into account factors such as customer awareness, customer willingness to adopt the measure, and market barriers.

Figure 33: Categories of Savings Potential



Source: Itron (2008)

This study focused on market potential, as these are the measures that are most likely to be implemented. Because market potential is influenced by a number of uncertain factors, the Itron analysis considered 10 scenarios that reflect various incentive levels and total resource cost restrictions. A full description of these scenarios can be found in Itron (2008). Personal communications with Itron indicated that the Base, Mid, and Full total resource cost restricted scenarios reflect the most realistic estimates of achievable potential. These scenarios demonstrate a wide range of conservative market potential estimates that serve as the basis of the SERC analysis (Table 28).

Table 28: Total Resource Cost (TRC) Restricted Market Potential Scenarios

Scenario Name	Scenario Description
Base Incentive TRC Restricted	Includes measures incentivized in the 2004-2005 program cycle with incentive levels that were available in 2006. Restricted to measures with a TRC ≥ 0.85.
Mid Incentive TRC Restricted	Includes all measures analyzed in the study with incentives halfway between those that were available in 2006 and full incremental costs. Restricted to measures with a TRC ≥ 0.85.
Full Incentive TRC Restricted	Includes all measures analyzed with incentives set to full incremental costs. Restricted to measures with a TRC ≥ 0.85.

Source: Itron (2008)

For each measure under consideration, the Itron databases provide estimates for measure, program, and incentive costs borne by the IOU, as well as the associated energy savings (kWh or therms). The databases also provide estimates for the number of yearly installations of each measure from 2007-2026. The installations are further classified as device retrofit, equipment conversion, or replace on burnout. The distinction between conversion and retrofit is that a conversion is replacing existing equipment with an alternate technology (for example replacing a furnace with a heat pump) while a retrofit is upgrading existing equipment with a more efficient device of the same type (that is upgrading and HVAC system from SEER 13 to SEER 15). Replace on burnout means the energy efficient equipment is installed when the existing equipment fails. These decision types have various cost implications and are therefore modeled differently in the Itron analysis.

The Itron analysis was performed for each California Energy Commission (Energy Commission) climate zone because some measures, such as heating, ventilation, and air conditioning (HVAC), are largely weather dependent. In order to approximate energy savings potential for weather dependent measures in Humboldt County, this analysis focuses on the PG&E service territory in Energy Commission climate zone 1. Geographically, Humboldt County is split approximately evenly between zones 1 and 2 (Figure 34). Approximately 94 percent of the county's population, however, lies in CZ 1 so energy savings potential for this zone, scaled by CZ 1 and Humboldt County's population, is used in this analysis. In most cases, Itron's assumptions are followed regarding the installation of measures appropriate for CZ 1. Based on local knowledge of energy end-uses in Humboldt County, however, measures involving residential air conditioning and pool pumps are excluded from this study.

For weather insensitive measures, Itron reported costs and energy savings estimates for the entire PG&E service territory. Population could not be used to scale these results because of the difficulty in estimating the population of an IOU service territory. Instead, residential and commercial building electricity and natural gas consumption

data were obtained from the Energy Commission and were used to scale costs and savings.

In the REPOP Model, the base incentive program described in

Table 28 is assumed to continue into the future regardless of any action taken by the local community. Therefore, a program level of zero percent corresponds to this base scenario. The full incentive program is assumed to be upper limit of efficiency efforts, so a program level of 100 percent is used to represent this scenario. Energy savings and costs associated with Humboldt County's efficiency program are assumed to scale linearly between zero and 100 percent.

Figure 34: Humboldt County Energy Commission Climate Zones

Source: California Energy Commission,
http://www.energy.ca.gov/maps/building_climate_zones.html

C.2 References

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APPENDIX D:
Regional Energy Sector Optimization Model

This appendix provides detailed descriptions of Regional Energy Planning Optimization (REPOP) Model. In section D.1, each supply submodel is detailed, demonstrating how the hourly availability of electricity production for that resource is modeled. Section D.2 covers the balance support submodels, which are the technologies associated with accommodating hour-to-hour discrepancies between demand and available supply. The demand submodels are described in section D.3. In section D.4, the energy balance algorithm is explained, which is the methodology used to dispatch supply to meet demand in each hour of the year. Section D.5 describes the algorithm used in the optimization of the energy balance model. Finally, sections D.6 and D.7 contain tables of model assumptions and references, respectively.

D.1 Supply Submodels

D.1.1 Natural Gas

The natural gas submodel assumes that the PG&E Humboldt Bay Power Plant can produce power any hour of the year. This assumption is based on the modular nature of the plant, which consists of ten 16 MW internal combustion engines. Maintenance and forced outages need not occur on all of the engines at once. The scheduling of maintenance is assumed to occur during periods of low demand and/or high availability of power from other sources. Table 42 presents the technical and economic assumptions associated with this technology.

D.1.2 Wind

The wind submodel is based on three years of modeled hourly wind data from NREL's Western Wind Dataset. The data were produced by 3Tier using mesoscale atmospheric modeling techniques covering the years 2004-2006. Data were available for several locations in the northern Cape Mendocino area, which represents the region of Humboldt County with the highest on-shore wind resource and closest proximity to existing transmission infrastructure (Figure 5 and Figure 6). Of the various data products provided by the dataset, the SCORE-lite corrected data are considered the most relevant to requirements of this analysis. These data represent a simulation of the output of 10 turbines instead of one. In addition, the SCORE-lite correction accounts for statistical deviations between the rated capacity of turbines and the output typically observed in practice (3Tier, 2010).

Model application:

- Given a source year (2004-2006) for the wind submodel and a plant capacity:
  - The SCORE-lite corrected data are scaled to the capacity of the plant and the resulting time series represents the hourly availability of wind power to the Humboldt grid.

Table 43 presents the technical and economic assumptions associated with this technology.

D.1.3 Wave

Availability of power from a wave energy power plant is based on spectral wave data from the National Oceanic and Atmospheric Agency's National Data Buoy Center and a Pelamis power matrix. Buoy 46022 is located approximately 14 nautical miles offshore from the mouth of the Eel River in water approximately 600 meters deep. A wave farm in the Humboldt County region would likely be located approximately 10 nautical miles from shore (PG&E, 2010a). The depth at this distance is approximately 140 meters, which puts the farm in sufficiently deep water that all wavelengths which can be captured by a wave energy converter are considered deep water waves (waves which have a wavelength less than twice the water depth). Hence, the observations at Buoy 46022 can reliably be used as a proxy for the wave environment at a distance of approximately 10 miles from shore. The buoy records spectral wave measurements at 10-minute intervals. A complete year of data are available for the following years: 1997, 1999, 2001-2003, 2005-2008.

Pelamis Wave Power Ltd. is a wave energy converter manufacturer based in Scotland and was the first company to deploy full-scale converters. They are also the only company that makes power conversion data from a deep-water device available to the public. These data, known as a power matrix, specify the amount of power produced by a device at a given sea state (Figure 35). The sea state is specified by the combination of the significant wave height (H_s) and energy period (T_e). The formulae for calculating H_s and T_e from spectral wave data follow.

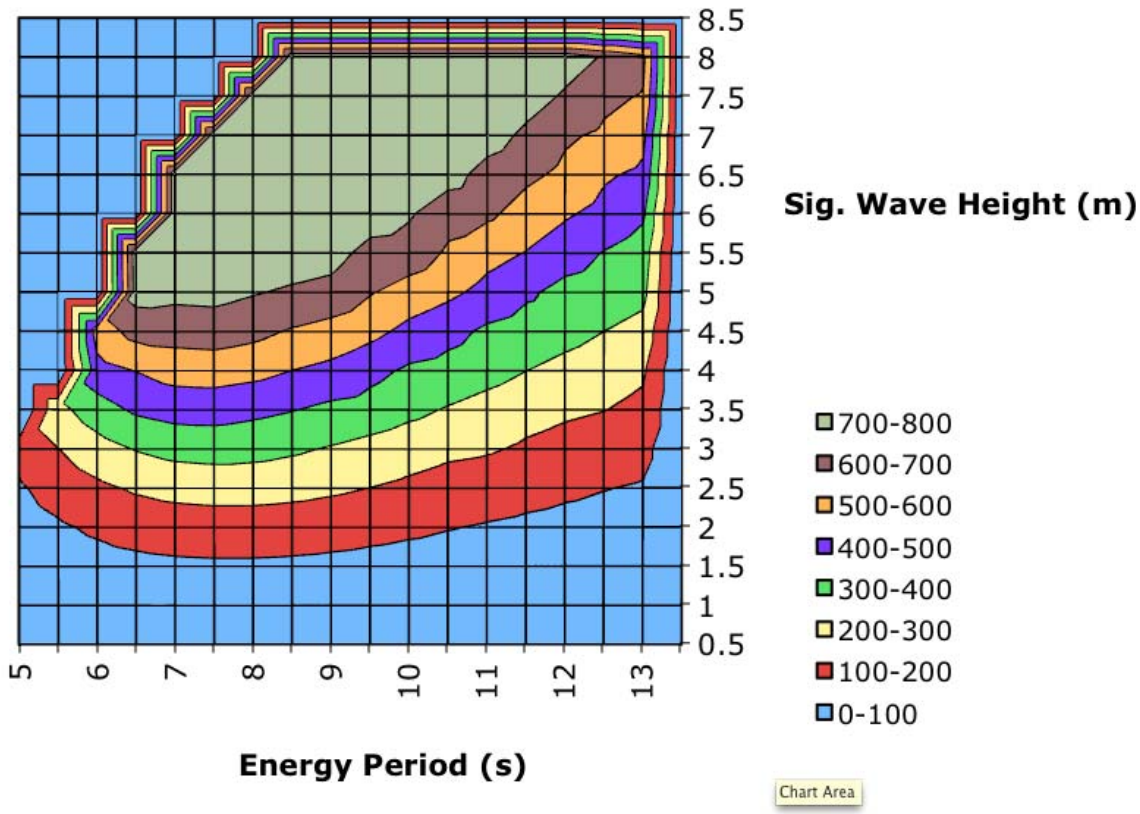
$$H_s = 4\sqrt{M_0}$$

$$T_e = \frac{M_{-1}}{M_0}$$

$$M_n = \int_f (f^n) s \; df$$

Where H_s is significant wave height in meters, T_e is energy period in seconds, M_n is the n-th moment, f is frequency in Hz, and s is the spectral density in m^2/Hz.

Figure 35: Power (kW) at Various Sea States Produced by the Pelamis Linear Attenuator



Source: SERC Staff based on Pelamis wave converter data (2010)

Model application:

- Given a source year (1997, 1999, 2001-2003, 2005-2008) for the wave submodel and a plant capacity:
  - Calculate H_s and T_e for every 10-minute interval of the year.
  - Use the Pelamis power matrix to estimate power production from a single WEC for each interval.
  - Average the data to an hourly interval, then scale to the plant capacity.

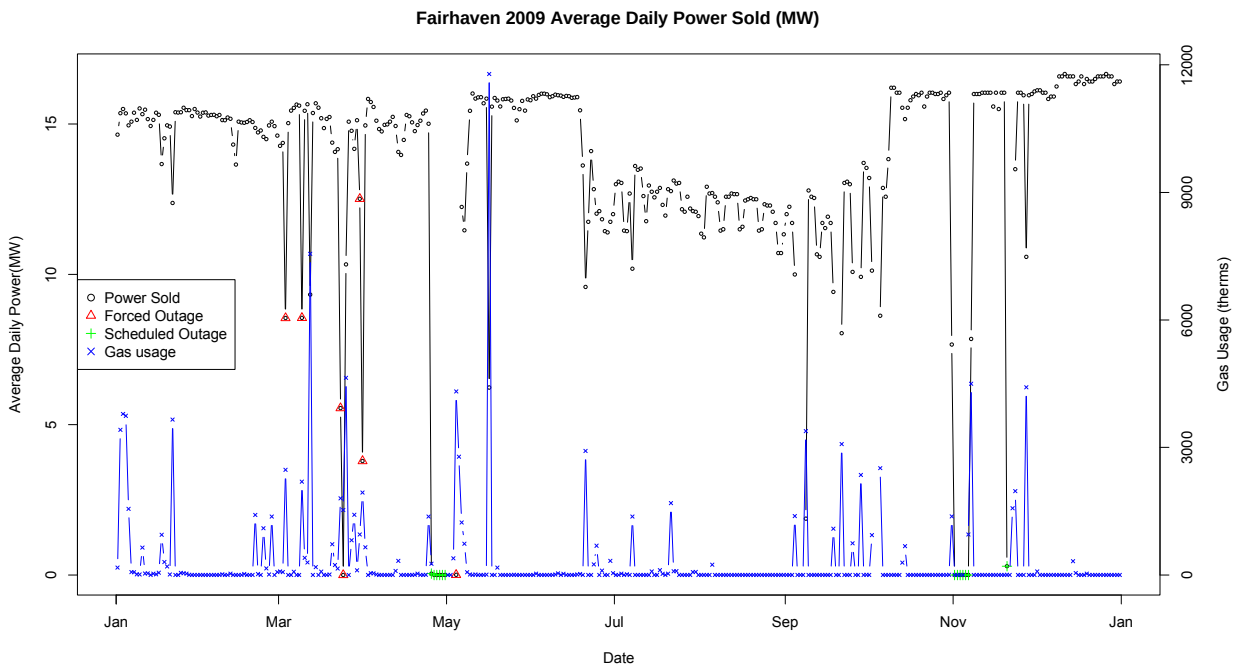
Table 44 presents the technical and economic assumptions associated with this technology.

D.1.4 Biomass

Availability of power from biomass power plants are modeled based on daily production data from the DG Fairhaven Power Plant (16 MW) for the year 2009 (Marino, 2010). These data include gross and net electricity production, biomass and natural gas

fuel consumption, and explanatory data concerning scheduled and forced outages. The entire time series is plotted in Figure 36. The summer months in which the plant operated at a reduced level is directly related to a contract dispute between the plant and its power purchaser. These data are therefore ignored in the development of the biomass production model as they represent atypical circumstances for plant operation.

Figure 36: Fairhaven Plant Production and Natural Gas Usage Data (Marino, 2010)



Source: SERC Staff (2010)

A composite stochastic time series model was developed to synthesize production data and outage occurrences from a biomass power plant. The Fairhaven data set was used to estimate model parameters. The authors recognize the potential hazard of using such a relatively small data set in stochastic model development. However, the model satisfied the following relatively simple, achievable criteria for model selection:

- The model should approximate observed daily variation in production unrelated to scheduled or forced outages.
- The model should approximate scheduled and forced outages at the same frequency and magnitude as the observed outages.

D.1.4.1 Model Formulation

The Fairhaven production data are converted into a daily capacity factor based on the maximum observed daily production in 2009. Data whose capacity factors are greater than or equal to 80 percent are used to model the operation of the plant under normal operating circumstances. The data exhibited an unexplained, gradual trend over the course of the year. The cause of this trend was ignored, as the primary intent of the model is to reproduce the daily variation in plant output. So the data were de-trended and the residuals were used in the subsequent analysis.

The data exhibit clear autoregressive behavior as demonstrated by the autocorrelation function for the series (Figure 37). A first order autoregressive moving average model (p=1, q=1) was determined to adequately reproduce the autocorrelation structure of the series. This model was used to generate a synthetic series of biomass production under normal operating conditions (

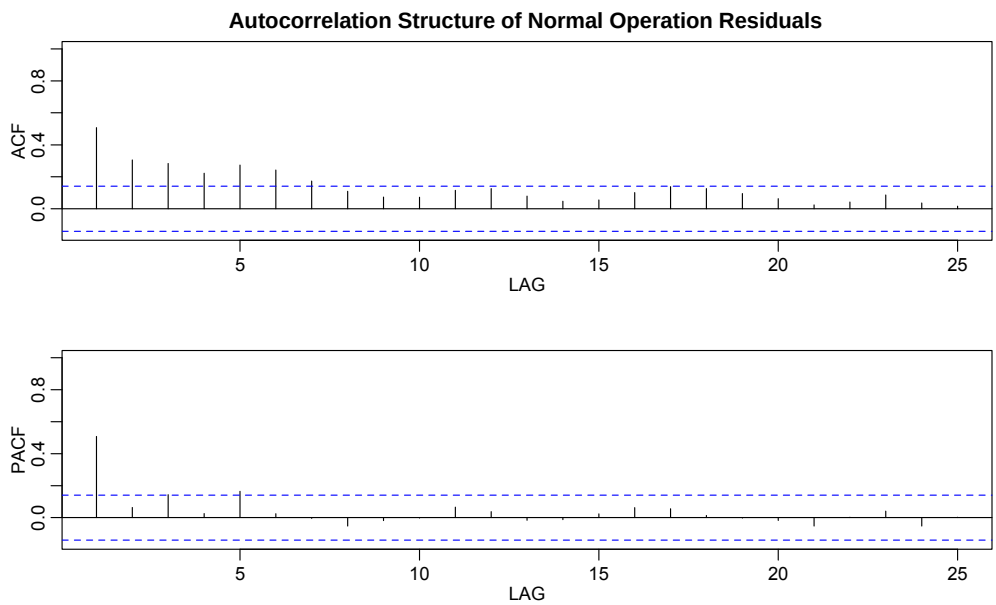
Figure 38). It is clear from the juxtaposition of the observed and synthetic time series in

Figure 38 that the synthetic series has a larger variance than the observed. However, the mean and autocorrelation structure are the same, satisfying the model selection criteria. The model for normal operating conditions follows the following form:

$$y_{norm} = ARMA(1,1) + \mu_{norm}$$

where y_{norm} is the synthetic series, $ARMA(1,1)$ is the time series produced by the fitted autoregressive moving average model, and μ_{norm} is the mean value of the original normal operating time series before being de-trended.

Figure 37: Autocorrelation and Partial Autocorrelation Function for Residuals of a Detrended Time Series of Normal Operation (Capacity Factor >= 80 Percent) at Fairhaven Power



Source: SERC Staff (2010)

Data whose capacity factors are <80 percent (with the exception of scheduled maintenance) are considered low operating conditions and represent events when the plant is partially or fully curtailed. These conditions can arise for a multitude of reasons. For the purposes of this model, only the magnitude and frequency of the occurrences need to be reproduced by the model. To model the frequency of occurrence, the set of inter-arrival (for example days between) of low operating events are treated as a sample (Figure 39). A truncated gamma distribution is used to model the inter-arrival times, with the following form:

$$x = gamma(k, \theta)$$

$$y_{inter-arr} = \begin{cases} 150, & x \geq 150 \\ round(x), & x < 150 \end{cases}$$

where k, θ are the parameters of the gamma distribution, x is the result of a random draw from that distribution, and $y_{inter-arr}$ is the value used to determine when the next low operation event should occur in the synthetic time series. Random draws from this distribution determine when low operation events will occur. To model the magnitude of each event, a transformed and truncated exponential distribution is fitted to the observed low operation capacity factors (Figure 40). The distribution has the following form:

$$x = exponential(\lambda)$$

$$y_{low} = \begin{cases} 0.8 - x, & x \leq 0.8 \\ 0, & x > 0.8 \end{cases}$$

where λ is the parameter of the gamma distribution, x is the result of a random draw from that distribution, and y_{low} is the resulting magnitude of the low operation event.

The final component to the biomass production model is scheduled outages. Based on personal communication with the operations manager at Fairhaven power, the authors assume that scheduled maintenance occurs twice a year, just before and just after rate period A, which runs from May 1 through October 31. Independent power producers with a qualifying facility contract receive higher prices for their power during period A, so scheduling maintenance around this period maximizes revenue. All biomass power plants in Humboldt County are assumed to use the same strategy in planning schedule outages. However, scheduled outages are not permitted to occur simultaneously, which is a reasonable assumption given that the plants all must coordinate with Pacific Gas & Electric as the local grid coordinator.

The model of scheduled outages is based on observed data, which indicate that on average a single maintenance outage occurs for 7 days. To introduce stochasticity, the duration of each new scheduled outage is modeled as a truncated Poisson distribution with a mean value of 7. The distribution is not truncated in the typical sense, all random draws less than 5 or greater than 14 are discarded instead of being pinned to the extents.

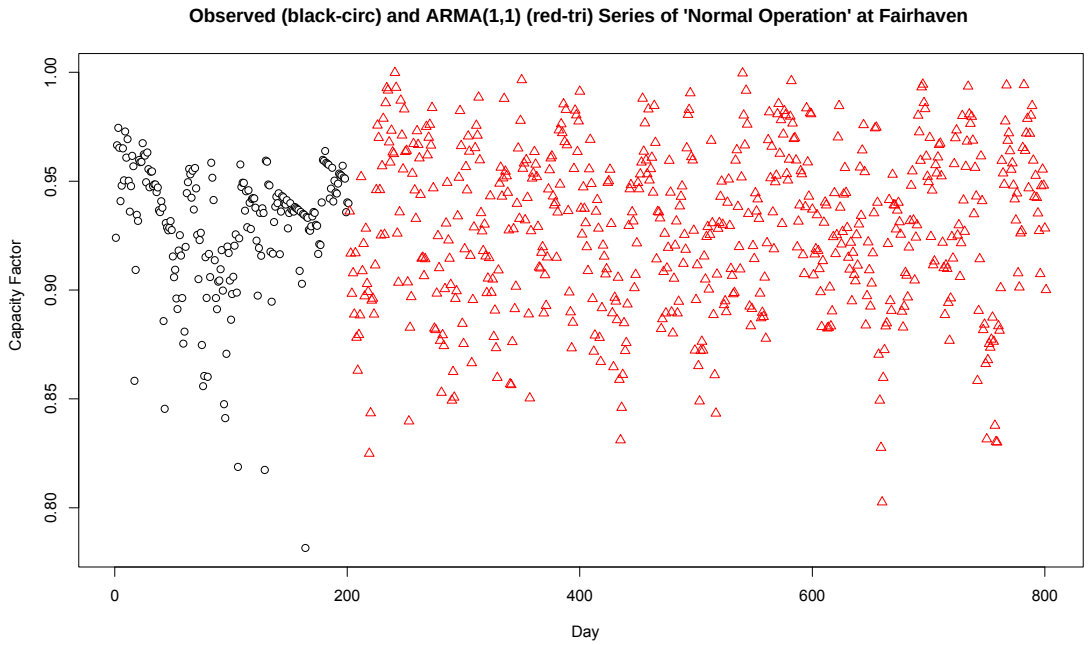
With these boundaries on the distribution, the value of the Poisson lambda parameter must be 5.8 for the overall distribution to yield a mean of 7. The model therefore has the following form:

$$y_{sched} = Poisson(5.8) \text{ (redraw if x<5 or x>14)}$$

The final synthetic time series for the biomass production model is generated in the following manner. For each biomass power plant being modeled:

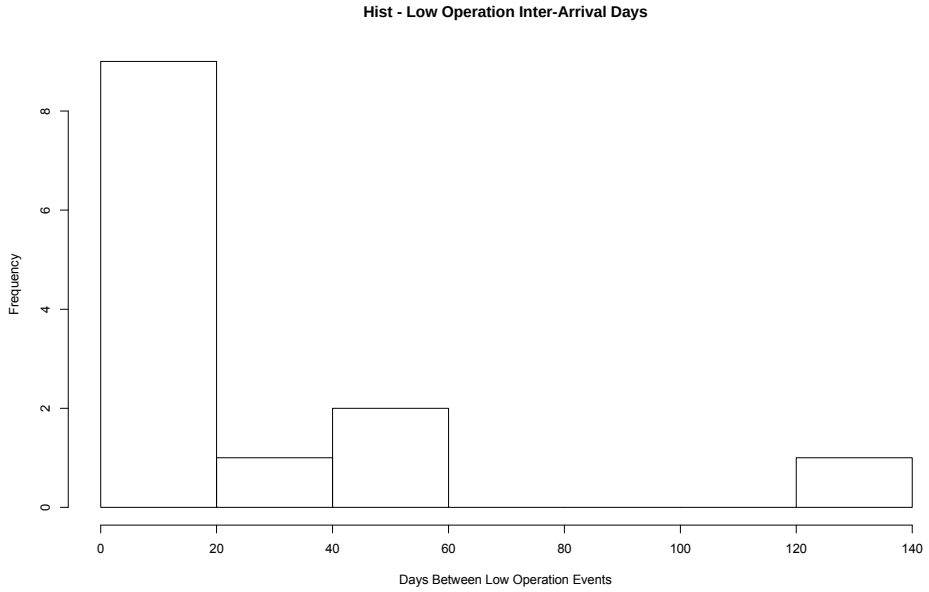
1. Use y_{norm} to generate 365 synthetic data points of the plant at normal operations.
2. Beginning at index 1 do the following:
   a. Increment the index by a random value drawn from $y_{inter-arr}$
   b. Replace the value at the current index with a random value drawn from y_{low}
   c. Repeat until the index is greater than or equal to 365.
3. For each biomass plant, draw 2 random values from y_{sched} to determine the length of the schedule outages before and after period A. Set the output of the plants to 0 for the determined number of days as close as possible to the beginning/end of period A but not overlapping any other plant.
4. The times series are all in terms of daily capacity factor. Multiply each series by the plant capacity to get production in units of MW.
5. Repeat each value of the time series 24 times to convert from a daily series to an hourly series
6. Finally, sum the output of all the plants to yield the overall biomass power availability for the year.

Figure 38: Observed (Black-Circle) and Synthetic (Red-Triangle) Time Series of Normal Operations at Fairhaven Power Plant



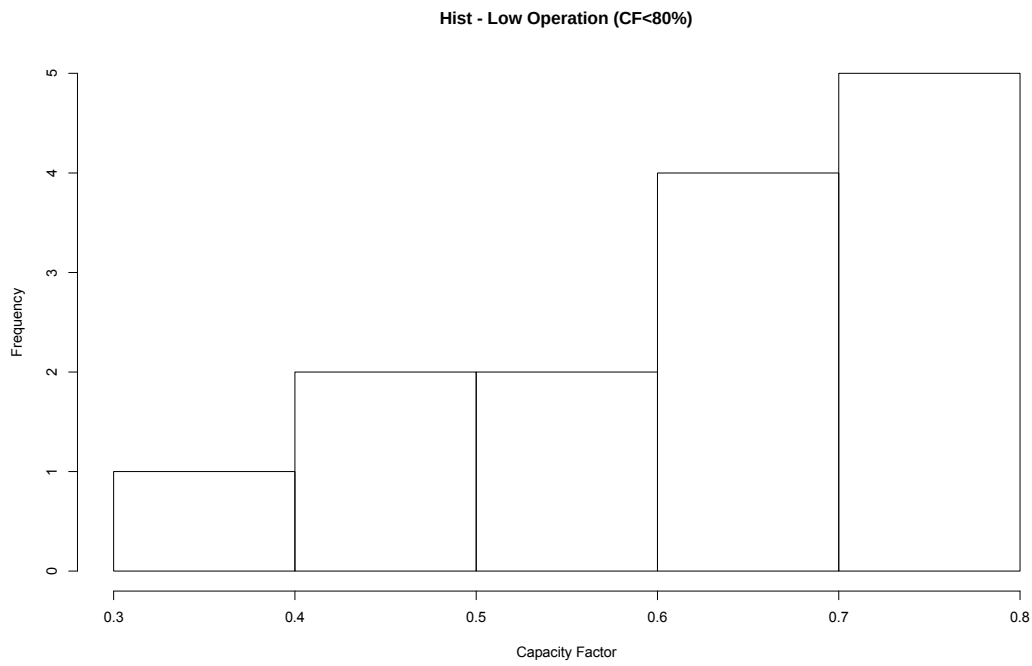
Source: SERC Staff (2010)

Figure 39: Distribution of Observed Inter-Arrival Times Between Low Operation Events. Data Modeled Using a Gamma Distribution



Source: SERC Staff (2010)

Figure 40: Histogram of the Magnitude of Low Operation Events Data Modeled Using a Transformed Exponential Distribution



Source: SERC Staff (2010)

Table 45 provides additional technical and economic assumptions associated with biomass power production.

D.1.5 Hydropower

The hydropower submodel is a composition of three models that capture separate types of small hydro generation in Humboldt County. There is a small dam in operation at Ruth Reservoir whose operation schedule is unlike any other hydropower installation in the county. The rest of the hydro installations are run-of-river micro-hydro systems whose production patterns are tied to the seasonal rainfall and stream flow. One such micro-hydro system, called Zenia, has a storage pond and therefore operates in a unique manner during the summer months when a premium price is placed on power generated during peak demand. Therefore, the Zenia hydro submodel operates slightly differently than the run-of-river submodel.

D.1.5.1 Ruth Reservoir/Matthew's Dam

Ruth Reservoir has a hydroelectric generation capacity of around 2 MW, with two 1 MW turbines. Monthly generation data are available for July 1983 through July 2009; daily downstream flow is available from the USGS for water years 1980-2009 (USGS station 11480410); the station is immediately below the dam (so these data include both flow captured to generate electricity and flow discharged over the spillway).

The model for hydropower production from Matthews Dam is:

$$P = \min(1.226, 0.00524149Q)$$

where P is power generation (MW), and Q is the discharge (cfs). This formula was determined through a two-step process, using the monthly average power generation and discharge data:

1. To calculate the maximum power capacity, average all points with discharge > 650 cfs
2. Choose the slope of the linear section to minimize the sum of the squares of the error.

D.1.5.2 Run-of-River Hydro (Without Peaking)

There is approximately 7.5 MW of installed capacity of run-of-river hydropower in Humboldt County (Table 29). Run-of-river hydroelectric power generation without peaking is modeled on a daily timescale by a seasonal autoregressive model:

$$E'_t = \begin{cases} 0.92840E'_{t-1} + 2.1480R_t & \text{Jun} - \text{Nov} \\ 0.98702E'_{t-1} + 2.1480R_t & \text{Jan} - \text{May, Dec} \end{cases}$$

$$E_t = C\min(E'_t + 0.90571, 24)$$

Where

E = daily energy generation (kWh/day)
E' = energy generation, unadjusted, as fraction of capacity
R = rainfall (in)
C = capacity (kW)
t = time (days)

This model was developed using the daily average power generation at Zenia and daily precipitation at the Alder Point Remote Automated Weather Station[6]. The autoregressive coefficients, coefficient of rainfall, and minimum power production were computed by minimizing the sum of squares of monthly residuals. The model was then scaled according to the power production of each system.

[6] Precipitation data available at: http://www.raws.dri.edu/cgi-bin/rawMAIN.pl?caCAPT

Table 29: Total Run-of-River Hydropower Generation Capacity in Humboldt County Area

Operator	City	County	Capacity (kW)
Baker Station	Bridgeville	Humboldt	1500
Mill and Sulphur Creek	Dinsmore	Humboldt	995
Tom Benninghoven	Garberville	Humboldt	25
STS Hydropower (Kekawaka)	Alderpoint	Trinity	4950

Source: Pacific Gas & Electric (2010b)

D.1.5.3 Run-of-River Hydro (With Peaking)

The Zenia system uses water from four creeks, which meet slightly upstream from the powerhouse. Three diversions flow into a storage pond with approximately 12 acre-feet capacity. Gross head is 757 feet from the storage pond to the powerhouse and 887 feet from the Bluford diversion to the powerhouse.

During late summer and early fall, the plant operates only during peak hours (noon to 6:30 PM weekdays); during late spring/early summer, the plant operates at a low level during off-peak hours and peaks at or near full capacity during peak hours.

The model for Zenia is based on the autoregressive model described above with the addition of peaking. Peaking is controlled by an algorithm that models the quantity of water in the storage reservoir. The input for the peaking algorithm is the daily average power generated by the non-peaking model described above. If the input drops below a threshold, a fraction of the input power is stored during off-peak times. At the start of the peak period (noon on weekdays), if the quantity of energy in storage exceeds a threshold, the power output is increased by a fixed amount until the peak period ends or the energy in storage drops below another threshold.

Table 46 provides additional technical and economic assumptions associated with this technology.

D.1.6 Solar Photovoltaic

The solar photovoltaic submodel is based on 15 years of modeled hourly solar radiation data from the National Solar Radiation Database (NREL, 2010). The model is based on data from Station 725945, Arcata Airport, as this is a coastal location in close proximity to Humboldt Bay. This region of the county is home to more than half of the total Humboldt population. Most of the remaining county population lives in areas with less coastal fog; therefore using a coastal data set serves as a conservative estimate of the countywide solar resource. The NREL database classifies the Arcata Airport data set as Class I, which is defined as follows (ibid): If less than 25 percent of the data for the 15-

year period of record exceeds an uncertainty of 11 percent, the station receives a Class I designation.

Model application:

- Given a source year (1991-2005) for the solar submodel and a plant capacity (in the case of PV, the plant capacity is the sum of the capacities of every installation in the county):
  - Determine the amount of solar radiation falling on a surface titled to 41 degrees for every hour of the year using the following formula: $I_{tilt} = I_{norm} * \cos(\theta) + I_{diff}$ where I_{tilt} is the solar irradiance on the titled surface, I_{norm} is the irradiance on a surface normal to the sun, θ is the angle of incidence between the sun and the titled surface in the current hour, and I_{diff} is the diffuse irradiance (everything except direct sunlight) on a horizontal surface.
  - For each hour, calculate the output from the entire plant using the following formula: $P = I_{tilt} * P_{cap} * D/I_{max}$ where P is plant output, P_{cap} is the plant capacity, D is the PV derate factor which accounts for all system losses (shading, dirty panels, wire losses, inverter losses, and so forth, a value of 75 percent was used in the model), and I_{max} is the solar irradiance corresponding to maximum output of standard PV systems (1000 W/m^2).

Table 47 presents the technical and economic assumptions associated with this technology.

D.2 Balance Support Technologies

D.2.1 Import/Export

The import/export submodel assumes that power can be transmitted in or out of the county any hour of the year. This assumption ignores congestion issues at Humboldt County's primary points of connection to the greater California grid. These issues are ignored due to the limited scope of this study and because adequate data could not be found to construct a model of congestion.

Table 48 presents the technical and economic assumptions associated with import.

D.2.2 Storage

The storage submodel assumes that the storage facility can act as an electric load or generator. The capacities at which the facility charges and discharges are independently specified and can be different magnitudes. Conversion losses are accounted for in the

charging, discharging, and storage (in the form of a decay rate) phases of the facility operations according to the following expressions:

$$\text{Charging: } \Delta E_{charge,h} = P_{charge,h} * \eta_{charge}$$

$$\text{Discharging: } \Delta E_{discharge,h} = -P_{discharge,h} * \eta_{discharge}$$

$$\text{Storing: } \Delta E_{stored,h} = -E_{stored,h-1} * \lambda_{storage}$$

where $\Delta E_{charge,h}$, $\Delta E_{discharge,h}$, and $\Delta E_{stored,h}$ are the change in energy stored in hour h due to charging, discharging, and retaining stored energy from the previous hour. $P_{charge,h}$ and $P_{discharge,h}$ are the rates of charging and discharging respectively in hour h, η_{charge} and $\eta_{discharge}$ are the conversion efficiencies for charging and discharging, and $\lambda_{storage}$ is the hourly decay of energy stored in the facility.

See Table 49 for the technical and economic assumptions associated with this technology. The following sections discuss the three primary storage technologies that were considered by the authors: batteries, pumped hydropower, and compressed air energy storage.

D.2.2.1 Batteries

Batteries can serve a broad range of applications and are efficient, modular, compact, portable, and capable of providing variable storage capacity. Drawbacks of batteries are high costs, short lifetimes, and the use of toxic materials. Relevant battery chemistries for large-scale renewable energy storage include: lead-acid, nickel-cadmium, lithium ion and sodium-sulfur. While all of these technologies show some promise and have been employed to some extent for utility-scale energy storage, sodium-sulfur (NaS) batteries are likely the best-suited battery technology for supporting large-scale renewables. This technology addresses some of the shortcomings of other battery chemistries such as low cycle lifetime and high cost, and has superior performance characteristics (

Figure 41).

Figure 41: Comparison of Sodium Sulfur (NAS), Lead-Acid, Lithium-Ion, and Nickel-Metal-Hydride Batteries

Comparison Table

Item \ Battery		NAS (Base)	Lead-Acid (Current)	Lithium Ion	Ni-H
Continuous Discharge Duration with rated output		6 hours	2 hours	3 hours	2 hours
Expected Lifetime (at standard conditions)		15 years	3 to 5 years	10 years	7 years
Size	MWh(1MW x6h)	1	3 times	2 times	3 times
Weight	MWh(1MW x6h)	1	6 times	2 times	6 times
Price	MWh x 15years	1	3 to 5 times	8 times	6 times
Notes	Self Discharge	No	Yes	Yes	Yes
	Memory Effect	No	No	No	Yes

Note: These data are typical values and change by the manufacturers

Source: NGK (2010)

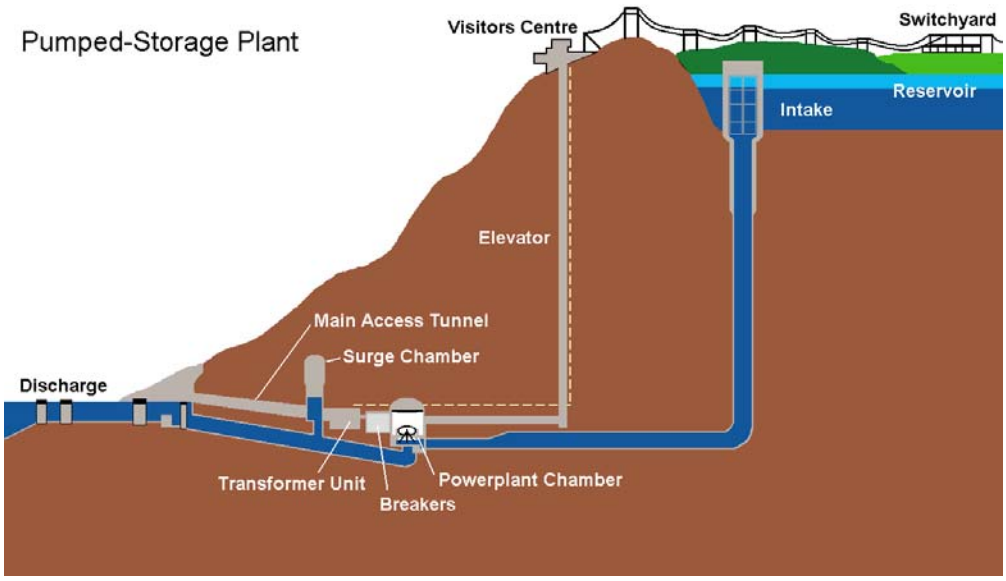
According to product specifications, NaS modules have a DC efficiency of about 89 percent, incur no self-discharge nor memory effect, and have an estimated 15-year service life depending on depth-of-discharge (2,500 cycles at 100 percent, 4,500 cycles at 90 percent, and 6,500 cycles at 65 percent). Their small footprint, lack of emissions, and insensitivity to ambient temperature makes them easier to site either indoors or outdoors in locations where renewable resources may be in abundance. NaS systems also require little to no regular maintenance.

The NaS battery was co-developed by the Tokyo Electric Power Company and NGK Insulators, Ltd. over the course of a decade. It has been demonstrated extensively in its native Japan at over 190 sites, including a 34 MW (245 MWh) facility for wind stabilization (Electricity Storage Association, 2010). As of 2009, NaS batteries represent the most mature energy management capable battery with 270 MW of globally installed capacity (Chi-Jen et al., 2009). NaS storage systems are also gaining traction in the United States. In 2007, American Electric Power, one of the largest investor-owned utilities in the United States, operated a 1.2 MW NaS storage system and was planning to install another twice that size (USA Today, 2007). American Electric Power has since installed other systems in West Virginia, Indiana, Ohio, and was building a 4 MW storage facility in Presidio, Texas in 2010 (National Geographic, 2010). Other major utilities are also pursuing installations of NaS storage systems for peak shaving applications. According to the Electricity Storage Association, annual production capacity planned for 2010 is approximately 150 MW.

D.2.2.2 Pumped Hydro

The most common type of large energy storage in the world today is pumped hydroelectric energy storage (PHES). PHES facilities generated 4,091 MWh of electricity in the US in 2010 (Energy Information Agency, 2011). The operation of a PHES facility is simple, two reservoirs at different elevations store water as shown in Figure 42. When cheap electricity is available (that is off-peak energy and/or surplus renewable energy) water is pumped from the lower reservoir to the upper reservoir and stored as potential energy. When the stored energy is needed, water is released from the upper reservoir to the lower reservoir through a turbine to generate electricity. The round trip efficiency of a PHES facility is 70 to 80 percent, with a plant life of over 50 years. Costs for PHES are between $1 million to 1.5 million per MW for construction costs and $12-25 per MWh for operations and maintenance costs.

Figure 42: Pumped Hydroelectric Energy Storage Schematic



Source: Connelly (2010)

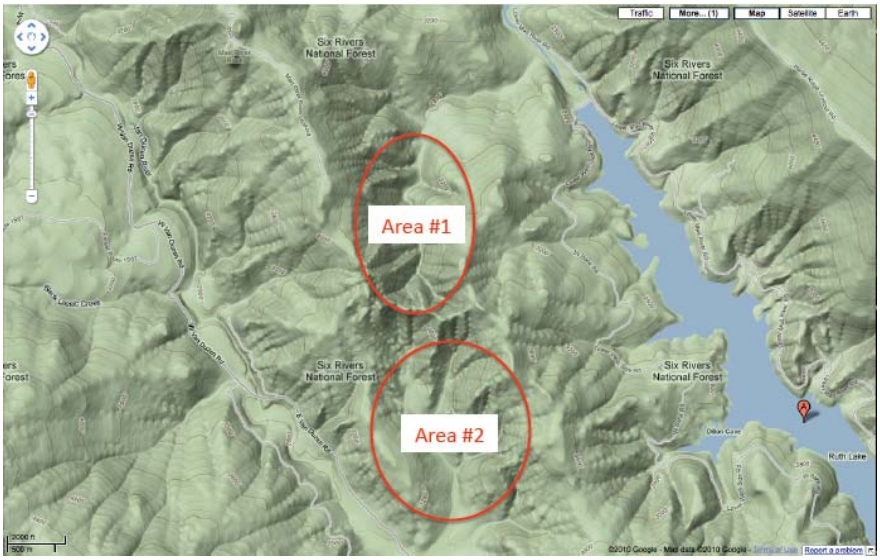
While PHES is one of the least expensive forms of energy storage, it is very site dependent. An ideal location would have a large body of water near mountains or hills to provide a large elevation change between reservoirs. A large elevation change is important because the potential energy stored in the water is directly proportional to the difference in elevation between the reservoirs.

There are many hurdles to developing new PHES facilities, including: environmental impacts, costs, long lead times for licensing, lack of transmission lines, and lack of appropriate sites. The most often cited concern for PHES is environmental impacts. Creating a reservoir often requires flooding a large area, which may have negative effects on habitats. Because of this, extensive environmental impact studies are required for new PHES projects and there is often opposition to new facilities. The large capital

cost associated with PHES projects is also often a concern for both investors and consumers. For these and other reasons, only one major PHES facility has been built in the United States in the last 15 years (Deane, Gallachoir & McKeogh, 2009) and the Energy Information Agency does not predict much PHES to come online in the near future (EIA, 2011).

In Humboldt County one potential site for a PHES facility is adjacent to Ruth Lake on the Mad River. A big advantage of siting a facility adjacent to Ruth Lake is that it could take advantage of existing infrastructure, including using the lake itself as the lower reservoir and using the existing transmission lines and interconnection facilities that serve the existing 2 MW hydroelectric facility located at the lake. As shown in Figure 43, there are two locations near Ruth Lake that exhibit potential for an upper reservoir. In either location an impoundment would need to be constructed and a penstock and powerhouse would need to be installed. Initial estimates for the capacity indicate that each reservoir has the potential to store enough water to power a 20 MW generator for more than two weeks continuously.

Figure 43: Potential Upper Reservoir Sites Near Ruth Lake.

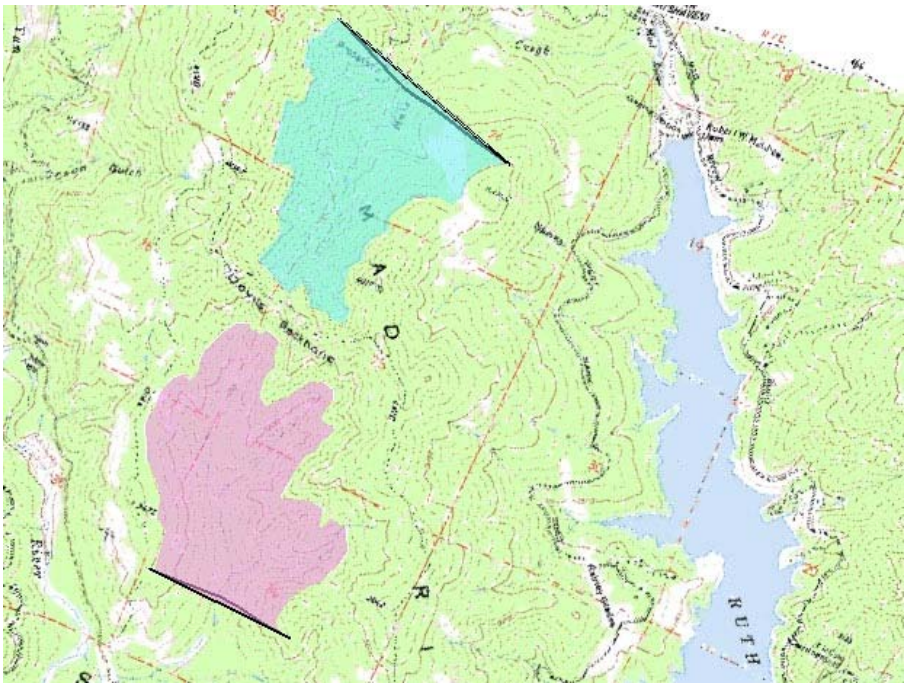


Source: Generated by Schatz Energy Research Center staff using Google maps.

D.2.2.3 Estimation of Pumped Hydro Upper Reservoir Capacity

To determine the volume of each potential reservoir as identified in Figure 43, Google Earth was employed with a topographic map overlay. For each location, a logical site was chosen for an impoundment that would create the reservoir. The maximum water elevation of reservoir 1 located in area 1 was chosen to be 3600 feet, and reservoir 2 in area 2 had a maximum elevation of 3360 feet (Figure 44).

Figure 44: Reservoirs Outlined on Topographic Map With Impoundment Locations



Source: Google Earth (2010)

For each reservoir, the authors estimated the surface area of a plane intersecting the reservoir at the contours in the topographic map using the area tool in Google Earth (Figure 45 and Figure 46). Once all of the surface areas of the contours were estimated, numerical integration was used to calculate the total volume based on the following equation:

$$V = \sum_{i=1}^{i=n} Area_i \times Depth$$

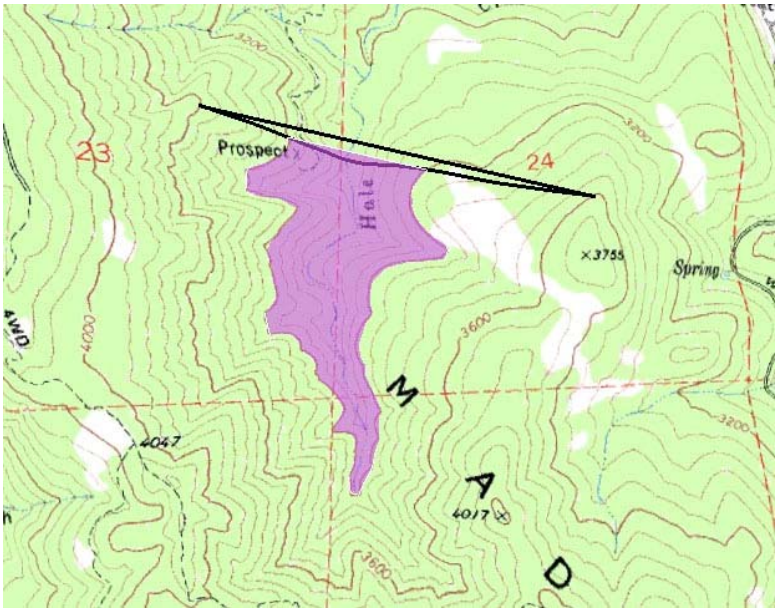
where V is the volume of the reservoir (ft^3)

n is the number of contour areas for the reservoir

Area is the area estimated for the contour slice (ft^2)

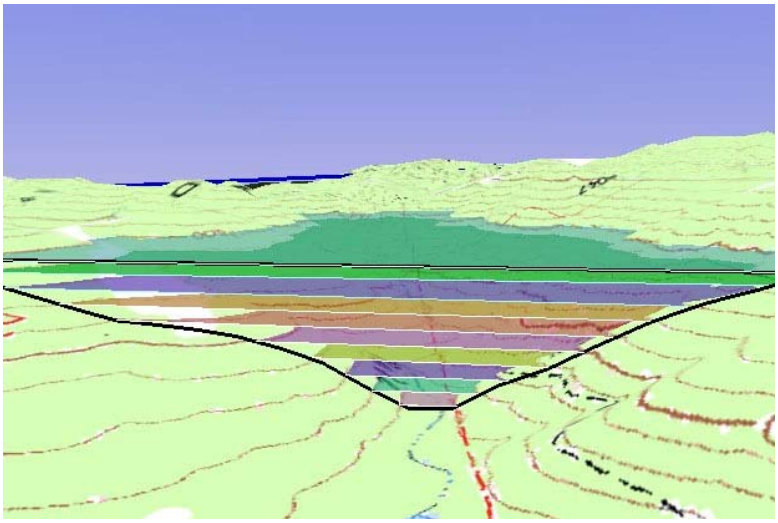
Depth is the distance between contour lines, for this map 80 feet.

Figure 45: One Area Slice in Reservoir 1



Source: Google Earth (2010)

Figure 46: Head-On View of All Area Slices in Reservoir.



Source: Google Earth (2010)

Reservoir 1 has an estimated volume of 134,000 Acre-feet (165 million cubic meters); reservoir 2 has an estimated volume of 132,000 Acre-feet (162 million cubic meters). The

authors performed several calculations for each reservoir to determine the number of days of storage for each reservoir. The scenarios investigated for each reservoir are:

- Continuous generation for a 2, 5, 10 and 20 MW generator.
- Head losses at the generator equal to 0, 20 and 50 percent of the static head.

For each reservoir, the authors assumed a maximum drawdown of 80 feet, a figure within the range of current PHES facilities – the Bath County Pumped Hydro Storage Station in Virginia has an upper reservoir that fluctuates up to 105 feet – and convenient because it is the difference between the contours lines of the topographic map. The amount of time of generation is estimated with the following equation:

$$t = \frac{V \times \rho \times g \times h \times \eta}{P}$$

where t is the time of full power generation (sec)

V is the volume of water used to generate power (m^3)

ρ is the density of water (kg/m^3)

g is the gravitational constant (9.8 m/s^2)

h is the change in elevation of the water (m)

η is the efficiency of the system, includes head loss and efficiency of turbine

P is power (w).

Each reservoir has enough capacity, even with a 50 percent loss in static head, to generate for 27 days at 20 MW, see results in

Table 30. Because the capacity is large, the size of the reservoir could potentially be reduced to decrease construction costs and environmental impacts. If the reservoir height was limited to 3360 feet for reservoir 1 and 3200 feet for reservoir 2, there would still be enough capacity for 2 weeks continuous generation at 20 MW with a 50 percent loss in static head.

Table 30: Days of Continuous Generation With the Given Generator Size and Head Loss

Generator	2 MW			5MW			10MW			20MW		
Head loss	0%	20%	50%	0%	20%	50%	0%	20%	50%	0%	20%	50%
Reservoir 1	595	476	297	238	190	119	119	95	59	59	57	29
Reservoir 2	558	446	279	223	178	111	111	85	55	55	44	27

Source: SERC Staff (2010)

D.2.2.4 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is a technology that can be used for storing large amounts off-peak and/or surplus renewable energy. Surplus electricity is used to compress air into an underground storage medium. When electricity is needed, the compressed air is heated and expanded in a turbine to generate electricity. The technology is currently commercially available at utility-scales and can provide long-term energy storage (on the order of hours to a few days). The technology has fast ramp up rates and good partial load efficiency.

The operation of a CAES facility is very similar to a conventional gas turbine (Brayton cycle), except the compression and expansions cycles are independent and happen at different times. Air is compressed using cheap energy (for example off peak and/or surplus renewable generation) and stored in a reservoir under pressure (20-60 bar, 290-870 psi). When the stored energy is needed the air is heated (typically using natural gas but other fuels can be used) and expanded in a generator as shown in Figure 47 (Succar & Williams, 2008).

Defining a single performance index for CAES is difficult because of the different inputs used: electricity to drive the compressors and natural gas or other fuel to heat the air during expansion. While there are many ways proposed for quantifying the performance (for example, a thorough discussion is given in (Succar & Willams, 2008, pgs. 36-41)) the most basic way to define efficiency is based on the ratio of electricity generated by the turbine (E_T) to the sum of the electricity used by the compressors (E_C) and the natural gas used during expansion (E_{NG}).

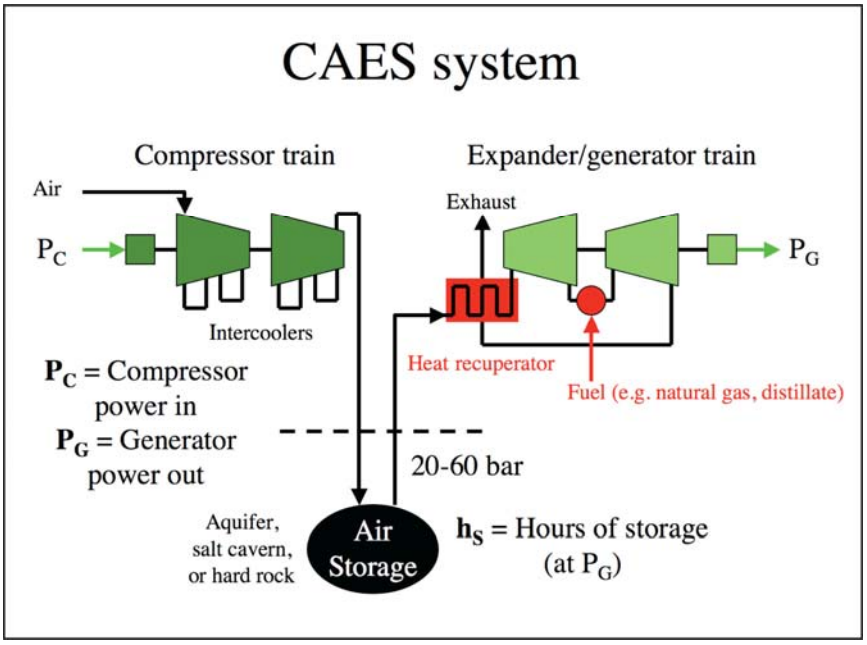
$$\eta = \frac{E_T}{E_C + E_{NG}}$$

Using this formulation with typical values from current CAES facilities, the efficiency is approximately 54 percent.

A major drawback to CAES is the need for additional fuel in the expansion process. There are schemes for minimizing, and potentially eliminating this need by utilizing heat storage for the heat created during the compression process. This type of advanced

adiabatic CAES (AA-CAES) system has not been built and as of yet is unproven (Electric Power Research Institute, 2003).

Figure 47: Typical CAES System Configuration



Source: Succar & Willams, 2008

Particular geologies are required for underground air storage. The geologies that are potentially suitable for a CAES facility are salt caverns, hard rock, and porous rock or aquifers. Smaller systems (approximately 10 MW) can also be built using pipes, either above ground or below, as the storage medium. Extensive geological studies must be done to determine whether a site meets the necessary requirements.

Costs for building a CAES project vary depending on the geology. The Electric Power Research Institute (EPRI) gives cost estimates for a CAES project with an assumed plant life of 20 years (

Table 31).

Table 31: Cost Per kWh for Various CAES Geologies

Geology	Cost ($/kWh 2003 dollars)
Solution mined Salt cavern	1
Dry Mined Salt Cavern	10
Underground rock caverns	30
Porous rock formations	0.10
Abandoned mine	10

Source: EPRI, 2003

There are currently two commercial CAES plants in the world, one in Germany and one in the United States. The Huntorf plant in Bremen, Germany, came online in 1978 and was designed to provide black start services to nuclear power plants and serve as a peaking power plant. It is now also being used to help balance an increasing wind load from Northern Germany. It has a maximum power output of 290 MW and can provide full power for three hours. The storage consists of two salt caverns with a total volume of 310,000 m^3 with operating pressures ranging from 48 bar to 66 bar (approximately 700 psig to 950 psig). The plant has operated reliably for three decades with availability and starting reliability of 90 percent and 99 percent, respectively.

The McIntosh plant in Alabama began operation in 1981. It has a power output of 110 MW and can provide full power for 26 hours. It uses a single 560,000 m^3 salt cavern as storage, with operating pressures ranging from 45 bar to 75 bar (approximately 650psig to 1,100 psig). After some initial startup problems the plant has had over 10 years of reliable operation with starting and running reliabilities over 90 percent. The McIntosh plant utilizes a heat recuperator that reduces fuel use by approximately 22 percent compared to the Huntorf plant. The operation parameters for McIntosh are similar to the Huntorf plant.

In addition to the two commercial plants, there are several CAES plants being planned. The largest is the Iowa Stored Energy Project. The proposed $400 million, 270 MW plant would utilize power from a 75-150 MW wind farm, in addition to cheap off peak electricity, to charge a sandstone aquifer. Service is expected to begin in 2015 (Iowa Stored Energy Project, 2011).

Pacific Gas and Electric is planning a 300 MW CAES plant in Kern County. In September 2009 they were awarded $24.9 million in matching funds from the California Public Utilities Commission for the project, which is currently in the early stages of planning. Underground saline rock formations would provide storage for up to ten hours of full generation (California Public Utilities Commission, 2010).

In Humboldt County there exists a potential for CAES in closed natural gas wells. There are many natural gas wells in the Eel River Basin that are currently not under

production that could be suitable sites for CAES. Extensive geologic testing would need to be performed to determine if the sites are suitable for development. Important parameters to assess are the permeability and porosity for the desired location. Estimated costs for a CAES system in the Eel River Basin may fall in the $0.10 per kWh range (

Table 31) as the geology in this region is characterized as porous rock.

Residual hydrocarbons may pose a potential problem for development of closed gas wells. Residual hydrocarbons could produce permeability-reducing compounds and corrosive materials when exposed to air. Furthermore, there could be the potential for combustion when high-pressure air is introduced in the presence of residual hydrocarbons. However, there are mitigation techniques that can be employed to reduce these risks (Succar & Willams, 2008).

D.2.3 Reserve Capacity

To model the reserve capacity required during any hour of the year, the authors conducted an analysis of the uncertainty associated with hour-ahead forecasts of demand, wind power production, and wave power production. The forecast method is a persistence forecast, meaning the demand or intermittent power production in the next hour is assumed to be equal to that in the current hour. In reality, grid operators can employ a multitude of forecasting techniques that produce results far more accurate than persistence forecast. However, a persistence forecast is employed as a highly conservative measure of the uncertainty associated with demand and production.

Using two coincident years of hourly data for demand, wind, and wave production in Humboldt County, first difference between every hour and the preceding hour is calculated yielding three vectors of forecast residuals. These vectors are analyzed to determine the overall variation in forecast error and how it depends upon the season, the time of day, and the magnitude of overall demand, wind, and wave capacity.

Ultimately, the reserve requirement is calculated via the following steps: 1) calculate the combined variance of the forecast error for all three vectors, 2) take the square root to get the standard deviation, 3) multiply by three. Assuming a normal distribution of forecast residuals, this three sigma reserve requirement means that reserve capacity will be adequate approximately 99.9 percent of the time. Using data specific to Humboldt County's electricity demand and wind and wave resource, the authors have found that the average reserve requirement with no renewables (demand alone) is equal to 12.7 percent of peak demand. The average reserve requirement if wind and wave alone meet 75 percent of load on an energy basis is 30.5 percent of the peak demand. These reserve requirements would be much lower if a more sophisticated forecasting method were chosen.

After running a sensitivity analysis that included various combinations of wind and wave generation that reached 250 MW combined and demand growth that reached a 165 MW annual average, it was determined that the 160 MW natural gas plant was always able to satisfy the reserve requirement without curtailing any of the other generation sources. However, there were frequent occurrences when the reserve requirement meant that electricity import was necessary to satisfy the local demand.

D.3 Demand Submodels

D.3.1 Population Growth

Population growth estimates were used to model the expected growth in demand for energy services. The population submodel is a simple exponential growth model that projects future population based on the U.S. Bureau of the Census 2010 estimate for Humboldt County and an assumed growth rate according to the following formula:

$$P_t = P_0 e^{rt}$$

where P_t is the future population in t years, P_0 is the present population, and r is the growth rate. The default growth rate (0.36 percent) is based on a study by Auffhammer and Aroonruengsawat (2010), which analyzed the impact of population, price, and climate on future residential energy consumption. They investigate three population growth scenarios for the state of California: 0.18 percent, 0.88 percent, and 1.45 percent. Their growth rates are based on data from the California Department of Finance (CA DOF, 2007). According to Department of Finance data, Humboldt County population is expected to grow at a rate 41 percent lower than the state average. So the three growth scenarios from the Auffhamer study are scaled to produce Humboldt-specific low, medium, and high growth rate cases: 0.07 percent, 0.36 percent, and 0.59 percent.

Given a projected population for Humboldt County, the question still remains whether there may also be a change over time in the per capita demand for energy services. For example, new appliances and electronic devices can create new demand for services that did not previously exist. Conversely, cultural changes resulting in an increased conservation ethic can reduce demand. Due to the constrained scope of this study, the authors simply assume that future per capita demand will be equivalent to present values. Therefore, to model growth in energy demand, demand is scaled linearly with population growth.

D.3.2 Humboldt Natural Gas and Electricity Demand

D.3.2.1 Baseline Electricity and Natural Gas Use

The estimate for baseline hourly electricity demand is based on a data set received from PG&E describing the whole-county electric load at 15-minute intervals from Jan 1, 2004 to December 31, 2008; it contains five years of data (PG&E 2010c). These data do not include on-site loads at industrial facilities that also produce on-site power (for example, some saw mills and pulp mill). The authors created an hourly countywide dataset by replacing any missing values and finding the average electricity use in each hour. The data from 2007 and 2008 are the best quality in the dataset in terms of having few missing values and having sector-level information in those years, so these years are used as the basis for further estimates of hourly electricity demand for various scenarios.

Natural gas is the most commonly used heating fuel in Humboldt County and is the best documented. The authors obtained a monthly natural gas data set parallel to the electricity data from 2004-2008.

Table 32 below lists the sectors and subsectors for which the authors arrived at estimates of electricity and natural gas consumption. In some cases there is not an exact match between the sector definitions for the two energy types. Overall, the residential sector dominates both electricity and natural gas demand in the county.

Depending on the scenario of interest, the demand algorithm adds and subtracts load shapes from the annual hourly data to modify its magnitude. A load shape is 8760 hourly values with energy units that can be added to the baseline load to modify it. If the values in the load shape are positive, the modified load in that hour will be higher than the baseline and vice versa.

Table 32: Electricity and Natural Gas Consumption in 2008 for Humboldt County

Electricity Sector Name	Electricity Consumption (MWh/year)	Percent of Countywide Consumption (%)	Number of Customers (#/year)	Natural Gas Sector Name	Natural Gas Consumption (therms/year)	Percent of Countywide Consumption (%)	Number of Customers (#/year)
Residential	**448,202**	**49%**	**56,353**	**Residential (Total)**	**22,463,924**	**56%**	**40,715**
Commercial Buildings (disaggregated below)	**238,151**	**26%**	**4,248**	**Commercial Buildings (disaggregated below)**	**8,600,807**	**22%**	**2,305**
College	*12,637*	*1%*	*51*	*College*	*1,357,227*	*3%*	*40*
Food / Liquor	*37,619*	*4%*	*145*	*Food / Liquor*	*366,175*	*1%*	*72*
Health Care	*18,219*	*2%*	*117*	*Health Care*	*1,129,455*	*3%*	*96*
Hotel	*11,733*	*1%*	*143*	*Hotel*	*908,970*	*2%*	*76*
Warehouse	*9,637*	*1%*	*271*	*Warehouse*	*108,465*	*0%*	*112*
Office	*40,621*	*4%*	*1,209*	*Office*	*1,023,157*	*3%*	*685*
Refrigerated Warehouse	*2,895*	*0%*	*22*	*Refrigerated Warehouse*	*5,901*	*0%*	*10*
Restaurant	*21,749*	*2%*	*340*	*Restaurant*	*1,118,732*	*3%*	*213*
Retail Store	*27,409*	*3%*	*559*	*Retail Store*	*374,410*	*1%*	*338*
Schools	*10,193*	*1%*	*172*	*Schools*	*576,920*	*1%*	*97*
Miscellaneous	*45,439*	*5%*	*1,218*	*Miscellaneous (includes any other Commercial)*	*1,631,395*	*0*	*567*
Commercial (Other)	**26,978**	**3%**	**723**				
Street lighting	**4,367**	**0%**	**1,137**				
				TCU	**98,058**	**0%**	**66**
Industrial	**117,496**	**13%**	**290**	**Industrial**	**6,366,366**	**1%**	**113**
Agriculture	**31,297**	**3%**	**914**	**Agriculture and Water Pumping**	**1,785,933**		**9**
Water Pumping	**11,460**	**1%**	**158**				
Mining and Construction	**1,185**	**0%**	**78**	**Mining (no construction included)**	**38,638**	**0%**	**29**
Unclassified	**26,421**	**3%**	**2,501**	**Unclassified**	**630,398**	**2%**	**717**
TOTAL	**905,557**	**100%**	**66,402**	**TOTAL**	**39,984,124**	**100%**	**43,956**

Source: CEC (2010a)

D.3.2.2 Heat Demand Estimates

The authors estimated the hourly demand for thermal energy[7] in Humboldt County buildings using a combination of top-down and bottom-up approaches. The top-down approach results in an overall estimate for heat demand on a monthly basis from natural gas sales data and census data, corrected for weather. The bottom-up approach estimates the relative hourly distribution of heat demand and the total space cooling demand in commercial buildings (cooling in residential buildings is essentially nonexistent) with DOE2 building energy models from the Energy Commission Database for Energy Efficient Resources (DEER). The combination of the top-down and bottom-up estimates results in an hourly profile for heating and cooling demand

The demand for thermal energy is ultimately driven by peoples' desire to change the temperature of their indoor environment, food, and water. Space conditioning is a dominant driver for thermal demand for heating and cooling, but domestic hot water, food preparation, and refrigeration are also significant. In specific cases, like district heating, losses in heating distribution systems can be a significant part of the load; there are not many systems of that type in Humboldt County.

Space heating and cooling demands are complex; they depend on the physical and operational features of buildings, weather, and interaction with the building occupants. However, given a relatively fixed fleet of buildings and occupants, the day to day changes in thermal demand can essentially be attributed to four meteorological factors: outside air temperature, humidity, solar radiation, and wind speed (Wojdyga, 2008; Heller, 2002; Enshen, 2005). Of those, air temperature is typically the strongest driver for thermal demands and is often referred to in terms of degree-days– defined as the difference between the daily average temperature and some neutral reference point, traditionally 65°F. Days with average temperatures above the reference point are counted as cooling degree-days (CDD) and those with temperatures below are counted as heating degree-days (HDD), for example, a day with an average temperature of 55°F is counted as 10 HDD. Typical weather patterns in Humboldt County[8] result in approximately 4,500 HDD and 0 CDD each year; Figure 48 shows the 30-year average values for Humboldt County in the context of the population-weighted distribution for cooling and heating degree-days in the United States as a whole. Humboldt County is fairly typical in terms of HDD but is on the extreme low end for CDD. There is very little need for active space cooling in Humboldt County because the population mostly lives in the mild coastal zone.

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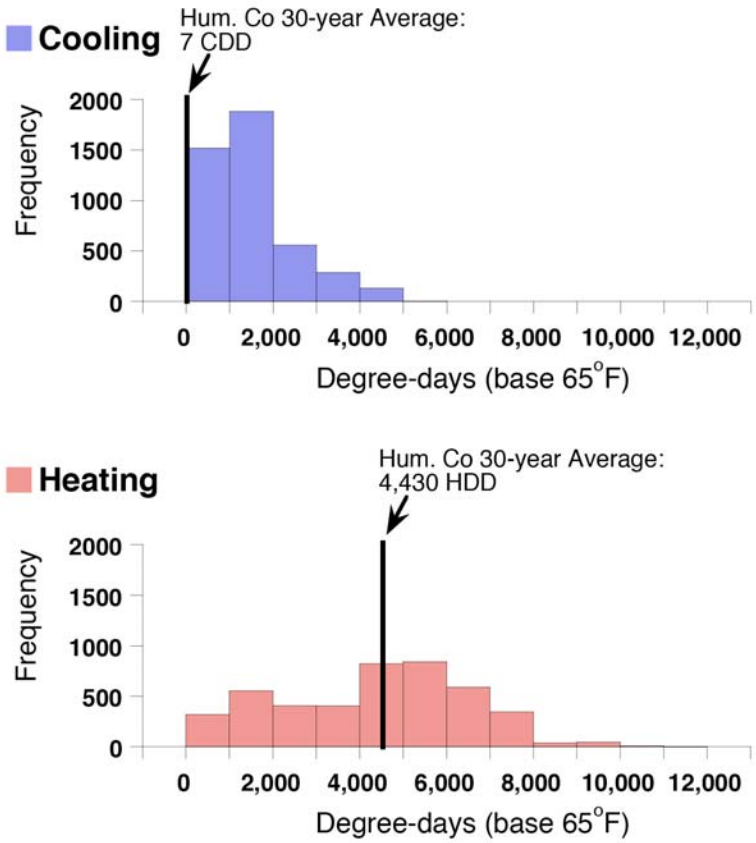
[7] Unlike many places, there is very little demand for space cooling in Humboldt County – another thermal demand component – although refrigeration for cold storage is similar to other places. Those refrigeration demands are considered weather independent for our study and are included in basic electricity demand estimates.

[8] The weather data presented here are from the Arcata / Eureka Municipal Airport, which is sited in a coastal area. While parts of the County experience much more varied (hotter and colder) weather than the airport, the majority of the County's population and buildings are located in the coastal zone.

Figure 48: Annual Cooling and Heating Degree Days; Nationwide Distributions (RECS 2005) and Humboldt County 30-Year Averages (NOAA 2010)



Source: SERC Staff (2010)

D.3.2.3 Residential Buildings in Humboldt County

The residential buildings sector is the best-characterized group in Humboldt County thanks to the decennial U.S. Census, which includes survey questions about housing stock. The approximately 130,000 residents of the county live in 60,000 housing units in 2010 – an average density of 2.2 persons per household, which is below the California average of 2.5 persons per household. Based on Census 2000 estimates, nearly 70 percent of the housing stock is single-family detached housing; 10 percent is mobile homes. The full estimate of housing stock distribution is included in Table 33.

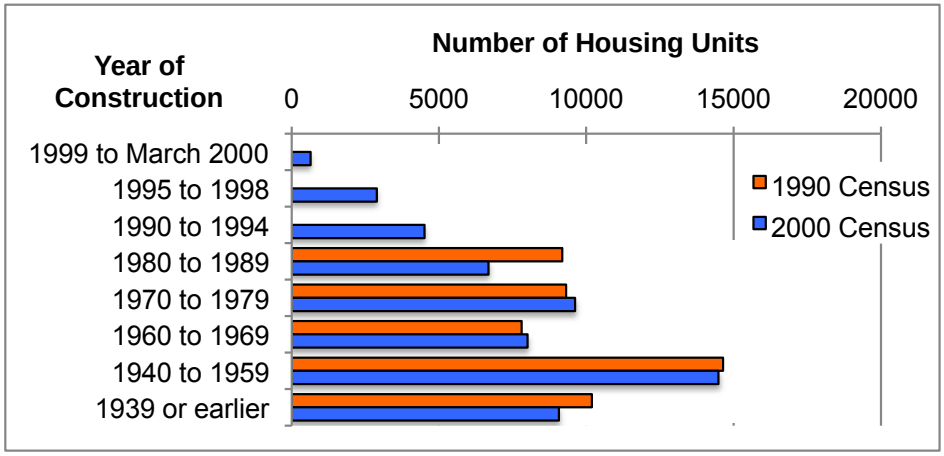
Table 33: Humboldt County Housing Stock

Type of Structure	Number	Percent
1-unit, detached	38,293	69%
1-unit, attached	1,542	3%
2 units	2,218	4%
3 or 4 units	3,387	6%
5 to 9 units	2,096	4%
10 to 19 units	1,160	2%
20 or more units	1,282	2%
Mobile home	5,481	10%
Boat, RV, van, etc.	453	1%

Source: US Census 2000

A housing boom occurred in parallel with a growing timber industry in the middle of the 20th century. The increased building in that period shows prominently in Figure 49, which shows the distribution in building age from the 1990 and 2000 Census. In 2000, 74 percent of the housing in use was constructed before 1980, when California Title 24 building codes were put into effect. The building codes have been very successful since then at reducing space conditioning demands, but relatively few Humboldt County homes were built under Title 24 codes. As new homes are built and old ones vacated, the energy efficiency of the residential housing fleet will continue to improve.

Figure 49: Age Distribution of Humboldt County Building Stock



Source: US Census 2000

D.3.2.4 Residential Heating Fuels

Table 34 shows the diversity of heating fuels used in California households; the data are from the RECS 2005 Microdata dataset produced by the Energy Information Administration. It also

includes results from the 2000 census for the primary space heating fuel of Humboldt County households. Of 468 California households that were surveyed, 408 (87 percent) had access to utility natural gas and the other 60 (13 percent) did not; the households are grouped according to utility gas access. The fraction of Humboldt County Households with access to utility-delivered natural gas in 2007 was 76 percent (from Energy Commission 2010a and Census 2000 data). The data show that those with access to natural gas overwhelmingly use it for water heating (96 percent) and large majorities also use it for space heating (80 percent) and cooking (66 percent). The percentage of Humboldt County residents who reported using natural gas as their primary heating fuel in 2000 was 62 percent, which is in line with the 61 percent estimate one would arrive at by multiplying the percentage of households with access (76 percent) by the typical fraction who use gas for heating, given they have access, in California (80 percent).

Those who lack access to utility gas must turn to other fuels for their thermal needs. In this case electricity is the clear market leader in spite of the typically high cost of electric water heating and cooking (and space heating if resistive coils are used). Californians report that they use wood for space heating at similar levels regardless of their access to utility gas; the median annual use regardless of utility gas access is 9 cords. The proportion of Humboldt County residents who use wood for their primary heating fuel is higher, 18 percent, but has fallen since 1990 from 27 percent and may be continuing to fall.

Overall, the data show that it is a good assumption that people in California who use utility gas for space heating also use it for water heating and likely use it for cooking.

Based on these data, the authors make the assumptions summarized in Table 35 for Humboldt County household water heating and cooking fuel utilization based on their space heating fuel. The space heating fuel market share estimates (shown in Figure 50) are an average of the 2000 Census results and a linear estimate for the 2010 results (that is, they are equal to the sum of the 2000 Census result and ½ the difference between the 1990 and 2000 results). The assumptions for domestic hot water and cooking are based on the conditional probability of a household in California using a particular water heating or cooking fuel given their primary space heating fuel, and are rounded to the nearest 10 percent.

Table 34: Primary Space Heating, Water Heating, and Cooking Fuels Used by California Households

		Has Access to Utility Natural Gas (n=408)	No Access to Utility Natural Gas (n=60)	Humboldt County Census 2000
Primary Space Heating Fuel	**Electricity**	16%	70%	10%
	Natural Gas	80%	0%	62%
	LPG	1%	15%	8%
	Fuel Oil	0%	5%	2%
	Wood	2%	5%	18%
	None	1%	7%	0.3%
Primary Water Heating Fuel	**Electricity**	3%	67%	
	Natural Gas	96%	0%	
	LPG	0.2%	32%	
	Solar	0.2%	2%	
Primary Cooking Fuel	**Electricity**	31%	80%	
	Natural Gas	66%	0%	
	LPG	0%	15%	
	None	3%	5%	

Data grouped by access to utility gas service shown; also shown for reference are Humboldt County households in general.

Source: RECS 2005 Microdata and US Census 2000

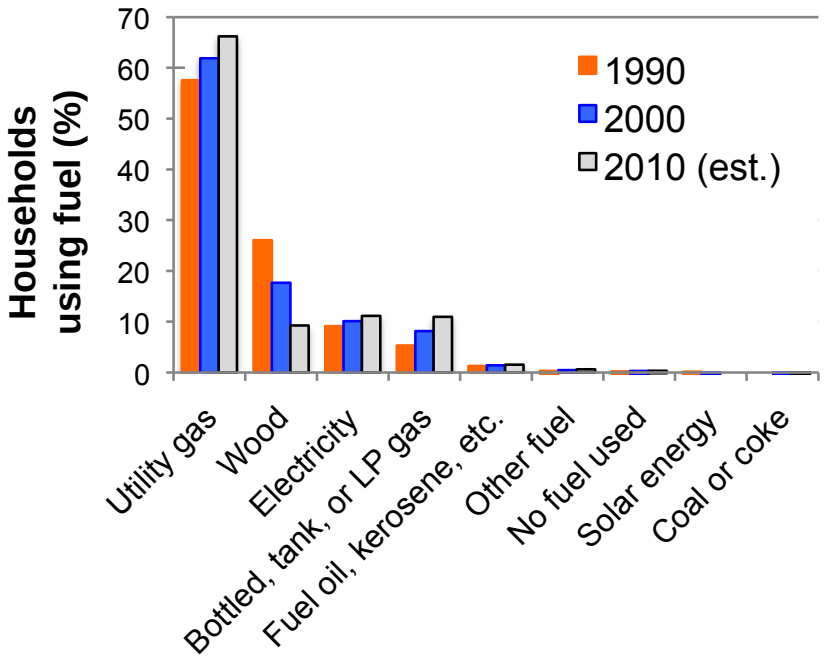
Table 35: Residential Sector Heating Fuel Market Shares and Conditional Water Heating and Cooking Fuel Market Shares Based on Space Heating Fuel

Space Heating Fuel	Water Heating Fuel	Cooking Fuel
Natural Gas (64%)	Natural Gas – 100%	Natural Gas – 70% Electricity – 30%
Wood (13%)	Natural Gas – 70% Electricity – 10% LPG – 20%	Natural Gas – 40% Electricity – 40% LPG – 20%
Electricity (11%)	Natural Gas – 60% Electricity – 40%	Natural Gas – 30% Electricity – 70%
LPG (10%)	Natural Gas – 15% LPG – 85%	Natural Gas – 10% Electricity – 30% LPG – 60%
Fuel Oil (1%)	Electricity – 100%	Electricity – 100%
Other (1 %)	Natural Gas – 50% Electricity – 20% LPG – 30%	Natural Gas – 50% Electricity – 30% LPG – 20%

Note: Baseline Humboldt County 2008 estimates.

Source: SERC Staff

Figure 50: Humboldt County Heating Fuel Market Shares in 1990, 2000, and Estimated for 2010.



Source: US Census 1990,2000 and SERC Staff

D.3.2.5 Residential Heating Technologies

Domestic Hot Water

Domestic hot water accounts for 67 percent of the non-weather related natural gas demand for California households who use natural gas to cook, heat water, and heat their home. The authors assume the same allocation for Humboldt County households that meet those criteria.

Typical Domestic Hot Water (DHW) performance (for example, the performance of a gas-powered water heater with a tank) is described in terms of energy factor (EF), which combines the efficiency of a burner with standby losses (Energy Commission, 2008). The 2008 Update to DEER describes an analysis of California tank water heaters. For the purposes of this study, the assumptions for the baseline water heater technology are summarized in Table 36. It is assumed that the baseline EF of water heaters in Humboldt County is evenly distributed among those that were identified as the typical water heater that was produced between 1993 and 2008. The burner efficiency is assumed to be the average burner efficiency among those identified in the California small gas water heater database (California Energy Commission 2008). The standby efficiency is inferred from the other two estimates. For electric water heaters, the energy factor is equal to the standby efficiency – 71 percent for the baseline estimate.

New construction and replacements of DHW will have to be in compliance with Energy Commission appliance standards, which specify a minimum EF of 0.62.

Table 36: Baseline Humboldt County Gas Water Heater Efficiency

Energy Factor	Burner Efficiency	Standby Efficiency
56%	78%	71%

Source: SERC Staff based on Energy Commission 2008

Home Heating Equipment

Gas furnace efficiency assumptions are based on the DEER documentation for 2005 (Itron 2005) and 2008 (California Energy Commission 2008). They are summarized in Table 37.

Table 37: Baseline Humboldt County Gas Heating Equipment Efficiency

	Single Family	**Multifamily**	**Mobile Home**	**Weighted Total**
AFUE (%)	78%	73%	78%	77%
Humboldt Co. Share (%)	69%	20%	11%	100%

Source: Itron 2005 and Energy Commission 2008

Cooking

Cooking accounts for 33 percent of non-weather related natural gas demands (according to analysis of RECS 2005 data for California households). The estimates of cooking efficiency are based on Lawrence Berkeley National Laboratory's Home Energy Saver documentation (Mills et al, 2008). For this analysis, the heat rate of electric ranges and ovens is assumed to be the theoretical lowest amount of heat that can be used to cook (culinary concerns and induction technology aside, among other simplifying assumptions). Therefore, the efficiency of natural gas cooktops or ovens is equal to the electricity requirements divided by the natural gas required for a similar appliance. The authors take the baseline assumptions about natural gas and electric stove/oven combinations from Mills et al, 2008 to make the baseline assumption presented in Table 38 below. The main conclusion is that the heat rate for natural gas cooking is 2.2 times higher than electric cooking; that same factor is assumed for cooking with LPG.

Table 38: Cooking Appliance Baseline Assumptions

Cooking Appliance Fuel	Electric	Natural Gas
Oven heat rate (kBtu/hr) [efficiency]	7.847 [100%]	11 [71%]
Oven hours of use per week	2	2
Stove heat rate (kBtu/hr) [efficiency]	3.412 [100%]	9 [38%]
Stove hours of use per week	7	7
Time-weighted efficiency	100%	45%

Source: Mills et al 2008

D.3.2.6 *Commercial Buildings*

The authors estimate that for most commercial sub-sectors, the proportion of buildings with access to natural gas is roughly equivalent to the proportion of Humboldt County's population with access (75 percent) and that every commercial building with access will use natural gas for heating, cooking, and hot water preparation. Based on local knowledge, 100 percent of the healthcare and college facilities are assumed within reach of natural gas (while there are exceptions, this rule is generally true in the county). Of the buildings without access to natural gas heat, trends are used from CBECS 2003 microdata for the Pacific Census Division (California, Oregon, and Washington). Table 39 below presents those trends for fuel utilization:

Table 39: Share of Heating Fuel By End-Use for Commercial Buildings in CBECS (2003), Pacific Census Division, Without Access to Utility Natural Gas (n=126).

Fuel	LPG	Electricity	Fuel Oil
Heating Share (%)	4%	79%	17%
Hot Water Share (%)	5%	78%	18%
Cooking Share (%)	4%	80%	17%

Source: CBECS 2003

D.3.2.7 *Commercial Building Heating Technologies*

Commercial space heating equipment in Humboldt County is often different from the equipment used in typical commercial buildings around the state of California. Anecdotally, commercial buildings in Humboldt County tend to be smaller and rely on technology that is typically found in residential construction. For instance, the authors are aware of at least three large commercial facilities in the area use multiple residential furnaces and air conditioning units to serve the building rather than a centralized system. This design practice leads to lower

efficiency than is typically possible. The trend is likely due to a lack of capacity in the area for best-practice commercial HVAC design and installation.

To account for the residential nature of many commercial buildings in Humboldt County, some of the baseline assumptions from the residential sector are applied to the commercial sector where appropriate.

Space Heating

Commercial space heating equipment in Humboldt County will be assumed to be equal to the equipment used to generate the baseline DEER 2005 – meaning an assumption of 80 percent thermal efficiency for gas heating equipment.

D.3.3 Heat Demand Algorithm

The following two steps are taken to develop hourly electricity demand for heating and monthly demand for various fuels:

1. Estimate Heat Demand: find the hourly demand for heating service across the county in each sector.
2. Apply Technology**:** use a fleet of heating technologies to meet the heating end-use service demand in each hour; develop a time series demand for fuels and electricity.

D.3.3.1 Estimate Heat Demand

The approach used to estimate countywide heat demand in commercial and residential buildings was to use monthly natural gas consumption to estimate the demand for heat in each sector on an end-use basis, accounting for the typical efficiency of equipment, market share (that is, percent of buildings in the sector who use natural gas as a heating fuel), and using an estimate of the fraction of the total natural gas that is used in each end-use category. In general, a month of natural gas use was disaggregated into end-use heat demands by the following approaches.

The estimates for heat demand in each sector began with monthly-billed natural gas data for a five-year period. The authors used a linear model for degree-days to estimate the split of natural gas consumption between space heating (weather dependent) and relatively weather-independent uses, namely domestic hot water (DHW) preparation and cooking. The basic equation for estimate space heating demand is presented below.

Equation 1:

$$Q_{HVAC\,load} = \frac{\eta_{HVAC}\left(\sum_{month}^{12} Q_{NG} - Q_{const}\right)}{\phi_{HVAC,NG}}$$

where:

$Q_{HVAC\ load,\ yearly}$ = the annual space heating load in a given sector

Q_{NG} = the monthly natural gas use

Q_{const} = the monthly weather independent natural gas use

$\phi_{HVAC,NG}$ = the percentage of buildings in the sector that use natural gas heat

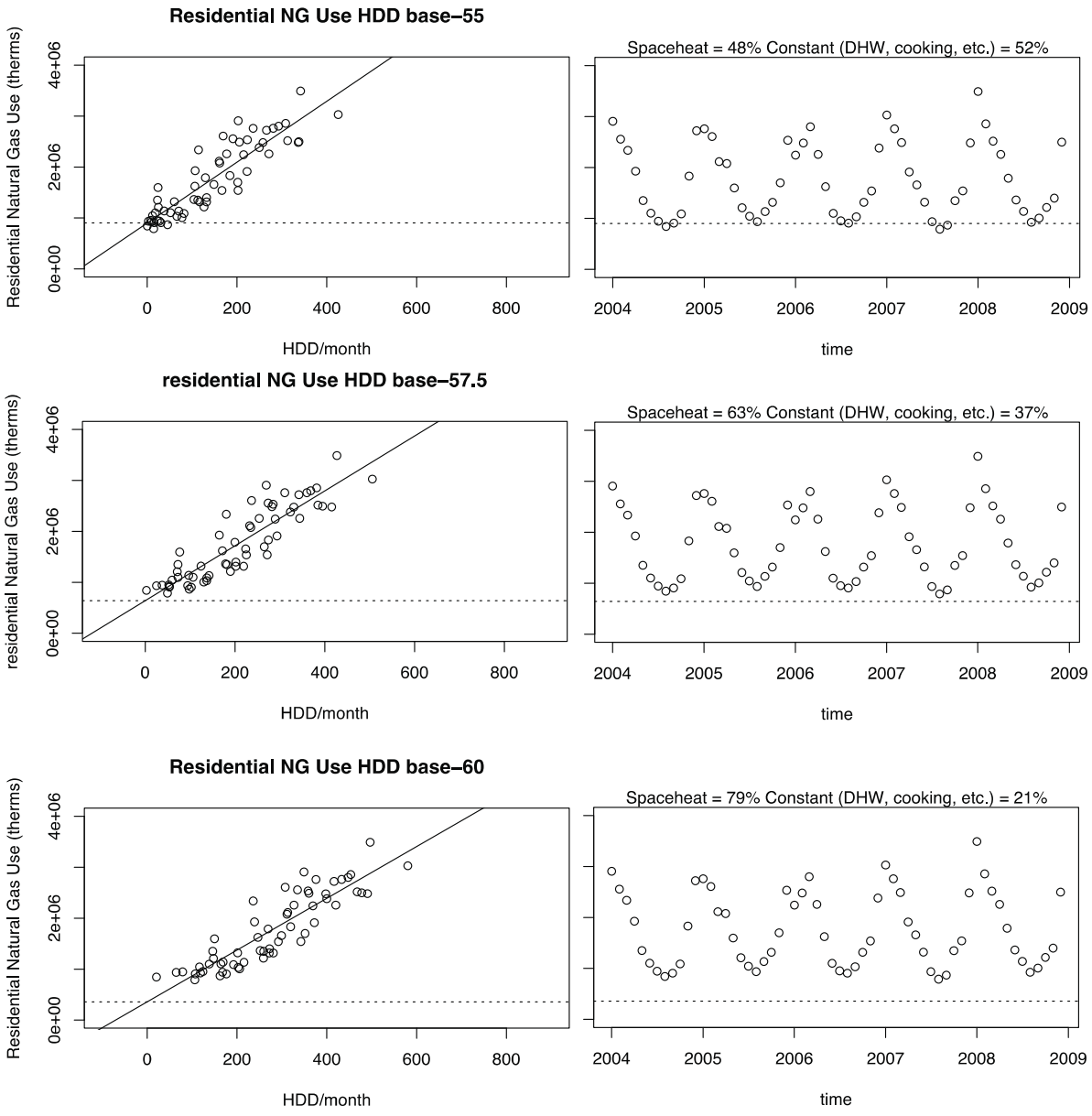
η_{HVAC} = the average thermal efficiency of natural gas heating systems

The term Q_{const} referenced in the equation above can be estimated by plotting HDD versus heating fuel consumption by month for a given sector, then using a linear estimate to find the fuel consumption when there are no heating degree days in a month. A critical factor in the analysis is the choice of baseline temperature for HDD estimates. The approach used by the authors is a combination of trial and error and practical knowledge of Humboldt county buildings.

Figure 51 shows how the choice of HDD base temperature affects the inference that can be made about relative fractions of space heat and DWH/cooking. Each row of plots uses a different base temperature (55°, 57.5°, and 60° F); the left column shows therms of gas in the residential sector versus HDD/month and the right shows a time-series of the gas consumption data on the same ordinate scale.

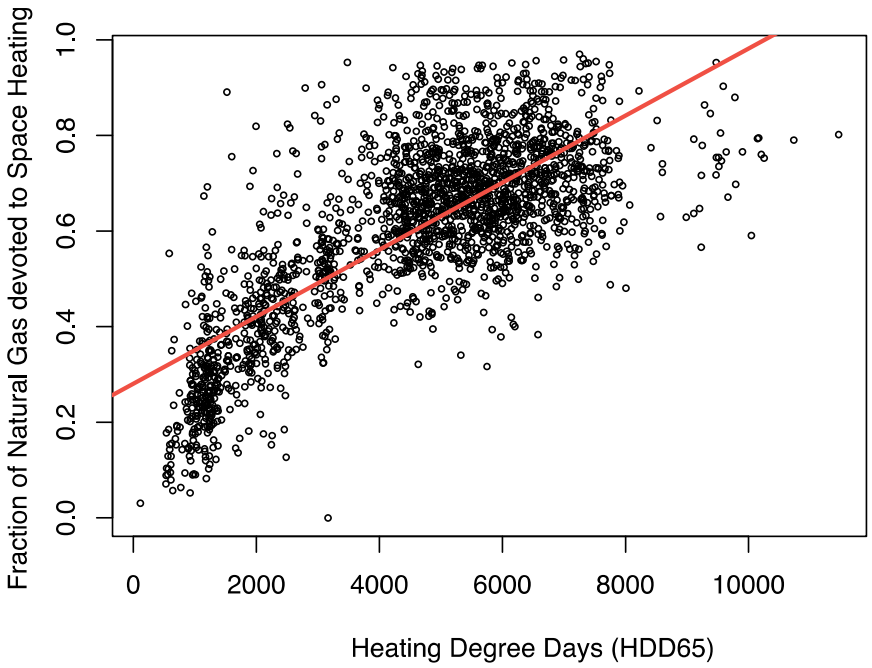
Figure 52 shows that among the RECS households, there was a relationship between the estimated fraction of natural gas use for heating and the annual heating degree-days. The plot includes a simple linear fit for the data, which is not a very good model for the data but provides some guidance about the general trend. If the homes in Humboldt County follow the general trend, space heating will represent about 60 percent of the natural gas use in residences (at approximately 5000 HDD/year). Based on that trend and anecdotal knowledge that there is some small amount of heating even in the summer in Humboldt County, the authors selected 57.5 F as a base temperature for heating in the residential sector. There was not as exhaustive a ground-truthing for the estimates in other sectors, which account for much smaller fractions of the overall gas use.

Figure 51: Residential Natural Gas Consumption Disaggregated Into Weather-Related (Space Heat) and Non-Related (Constant) Parts Using Three Different Base-Temperatures for Heating Degree Days



Source: SERC Staff

Figure 52: Fraction of Natural Gas Attributed to Space Heating Versus Yearly Heating Degree Days (Base Temperature 65°F).



Source: SERC Staff based on RECS 2005 Microdata

With monthly natural gas data split into weather-related and non-related parts for each sector, there was a further breakdown of the non-related parts into cooking and hot water preparation. Those fractions were informed by assumptions put forth in Itron 2005, CBECS, and others. With an assumption that the natural gas users are representative of all the heating consumers in the county in terms of demand levels, Equation 2 is used to estimate the total demand for heating energy service on a monthly basis in each sector, and end-use category. The result of the calculation is an estimate of the demand for heat (in GJ) in each.

Equation 2

$$EUI_{i,j,k} = \frac{C_{f,j,k} \times F_{f,i,j} \times \eta_{f,i}}{S_{f,i} \times S_{f,k}}$$

where:

f	= fuel "f"
i	= end-use "i"
j	= month "j"
k	= sector "k"
EUI	= end-use heat intensity (Joules)

C = consumption of fuel f in month j

F = fraction of consumption of fuel f attributed to the end-use i given 100 percent market share; may be a function of month j.

$\eta_{f,j}$ = efficiency of end-use for fuel j in sector j

$S_{f,i}$ = market share of fuel f for the end-use technology i

$S_{f,k}$ = market share of fuel f among the sector k.

The monthly heating demands (now in terms of sector and end-use) are broken down further by applying hourly load shapes. The load shapes are drawn from Itron 2005 and in some cases (that is, for residential and commercial buildings) are customized for Humboldt County weather in 2008 using the basic DOE2 energy models that informed DEER originally.

The resultant hourly loads are for the baseline fleet of buildings and heat end-users in the county and are assumed to be applicable to future buildings as well (that is, there is no provision built into the model for heating load reduction from weatherization programs, and so forth)

D.3.3.2 Apply Technology

A fleet of technology is deployed to meet the hourly demand for heating service in each sector. The technologies can be baseline-only or include a mix of baseline and updated technology (for example, switching from natural gas furnaces to electric heat pumps or using a more efficient furnace). To arrive at estimates for fuel or electricity demand in each hour, Equation 2 is recast in terms of $C_{f,j,k}$ as shown below:

$$C_{f,j,k} = \frac{EUI_{i,j,k} \times S_{f,k}}{\eta_{f,i}}$$

Using this equation, the energy use intensity in each hour is scaled by market share for each fuel and the efficiency of the conversion technology. The demands for each fuel are summed across the sectors to arrive at an hourly demand for the diverse fuels used to provide heating services to Humboldt County homes, businesses and other facilities.

D.4 Energy Balance Algorithm

The energy balance algorithm reconciles the demand with the available generation according to specified priorities in every hour of the year while satisfying reserve requirements. An energy storage strategy is implemented as part of the energy balance algorithm.

A simplified formulation of the algorithm follows:

1. Always meet reserve requirements.
2. Meet demand with available supply of priority.

3. Export excess power from generators whose priority is below the export priority threshold.

The reserve requirements are based on the reserve submodel described in Appendix D.2.3. Each generator has a reserve fraction parameter that indicates the fraction of the generator's unused capacity that be counted toward the reserve requirement for a given hour.

The following pseudo code details the steps followed in the energy balance algorithm to reconcile all of the demands and priorities required for power dispatch. Table 40 provides example parameter values for generators; these are helpful to decipher how the mechanics of the algorithm dispatch power within the constraints on the grid.

Table 40: Example Parameter Values Helpful for Illustrating the Energy Balance Algorithm

Generator	Capacity	Priority	Stability Share	Reserve Fraction	Min Turndown
Renewables (wind, wave, etc.)	40	1	0 (1 for hydro)	0 (1 for hydro)	0
Biomass	60	2	1	1	10
Storage	15	3	0.2	0.2	5
Gas	150	50	1	1	0
Import	60	99	1	1	0
Export Priority Threshold: 10 (generators with priority greater than this will never export)					

Source: SERC Staff

For each hour of the year:

1. Update generation availability of storage facility based on amount of energy stored and discharge efficiency.

2. For each generator:
   a. Load available generation for this hour
   b. *If priority < export priority*:
      i. initialize generator as supplying all available power
   c. *If priority > export priority*:
      i. initialize generator as supplying the minimum turndown power.

3. For each generator in ascending order of priority:
   a. *If demand exceeds supply and available generation exists for this generator*:
      i. Increase generator until demand is met or full capacity is reached.

4. Test special case when import and export are simultaneously occurring.
   a. *If both occurring*:
      i. Turn import down until export becomes zero or import becomes zero, whichever occurs first.

5. Test spinning reserve criterion: sum(gen. production * reserve fraction) >= reserve requirement for the hour.
   a. *If reserve not met*, then for each generator with reserve capability in reverse order of priority:
      i. Turn down generator until reserve requirement is met or minimum turndown is reached.

6. Test that turndowns haven't reduced supply below demand:
   a. *If demand is not being met*, then for each generator that has no capacity for reserve (import will typically be the only generator that meets this criterion):
      i. Increase generator until demand is met or generator capacity is reached.

7. Test transmission criterion: export <= transmission constraint.
   a. *If export exceeds transmission limit*, then for each generator in reverse order of priority*:*
      i. If a regular generator (non-storage), turn down the generator until one of the following occurs: the transmission criterion is satisfied or the minimum turndown is reached.
      ii. If the generator is a storage facility, then the minimum turndown will actually be negative reflecting that the facility can become additional load. The minimum turndown for the facility will be set according the facilities operating strategy.

D.5 Optimization Algorithm – Differential Evolution

The authors chose Differential Evolution as the optimization algorithm. Differential Evolution is a global optimization technique, also called direct search approach, developed by Rainner Storn and Kenneth Price. As described by the inventors, the approach was designed with the following beneficial properties (Storn, 1997):

1. Ability to handle non-differentiable, nonlinear and multimodal cost functions.
2. Parallelizability to cope with computation intensive cost functions.
3. Ease of use, for example few control variables to steer the minimization. These variables should also be robust and easy to choose.
4. Good convergence properties, for example consistent convergence to the global minimum in consecutive independent trials.

The set of decision variables and their limits composes the decision space. With n decision variables, the decision space is n-dimensional. Direct search optimization approaches explore

the *n*-dimensional decision space with a set of NP particles, each of which is an *n*-dimensional vector containing a value for each decision variable. In each iteration, or generation, of the algorithm, the particles are potentially updated via some scheme (multiple approaches are possible). The scheme involves evaluating the objective function for a set of new candidate particles and then choosing to replace or retain the particles from the previous generation with some or all of the new particles. The process repeats until a set of convergence criteria are satisfied.

The scheme for differential evolution used in this study is described below (Storn, 1997):

1. For each of the NP particles:
   a. Select 3 other particles, A, B, and C, which must be distinct from each other and from the originating particle, O.
   b. Create candidate particle P using the following vector arithmetic: P = A + F(B-C), where F is a constant scaling parameter which lies on the range [0,2].
   c. For *n*-1 dimensions of the candidate particle do the following:
      i. perform a random draw from the uniform distribution between 0 and 1.
      ii. test if the random value is greater than CR, another parameter of the algorithm called the cross-over parameter that lies on [0,1].
      iii. if the random value exceeds the parameter, replace the value in particle P with the corresponding value in particle O.
   d. Evaluate the objective function, or fitness, of the candidate particle: Obj(P).
   e. If Obj(P) < Obj(O), then replace particle O with particle P
2. Test the stopping criteria, if not met, go to step 1.

Based on the recommendations in Pederson (2010), the dimensionality of the problem, and the computation resources at the authors' disposal, the values in Table 41 were chosen for the differential parameters in the authors' implementation of the optimization.

Table 41: Differential Evolution Parameter Used in the Regional Energy Sector Optimization Model

Parameter	Description	Value
n	Dimensionality of the decision space	11
NP	Number of Particles	69
F	Scaling factor	0.66
CR	Cross-over rate	0.94
Maxiter	Maximum number of iterations	250

Source: SERC Staff based on Pederson (2010)

The stopping criteria test that the value of the objective function for all NP are close to each other as measure by the percent difference between each particle and the minimum value. Depending on the objective function used, the value chosen for the threshold ranged from 0.05 percent to 0.1 percent.

D.6 Technical and Economic Assumptions

The following tables (Table 42 through Table 49) present key technical and economic assumptions by technology type as used in the Regional Energy Planning Optimization Program (REPOP). When relevant, data sources and/or justifications are attributed to the model assumptions.

Table 42: Technical and Economic Assumptions for the Natural Gas Submodel

Technology	Natural Gas Power Plant			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	163	MW	Existing plant; no new generation assumed.
	Current Day	163	MW	
	Minimum 2030	163	MW	
	Maximum 2030	163	MW	
Production Characteristics	Data Sources	Assumed that maintenance is staged and therefore the plant can produce any hour of the year.		
	Capacity Factor	Variable	%	
Fixed Costs	Capital	1450	$/kW	PG&E[9]
	Operations	27	$/(kW*year)	
Variable Costs	Operations	10	$/MWh	
	Fuel	48	$/MWh	SERC Staff[10]
Lifetime	Economic lifetime	25	years	Wartsila[11]
Impact	Local Jobs	0.2, 0.07	jobs/MW (construction, operation)	JEDI[12]
	Economic Output	28, 8	$/kW (construction, operation)	
	GHG Emission	0.45	tCO2e/MWh	Wartsila[11]

Source: SERC Staff

[9] PG&E Application for Certification of the Humboldt Bay Repowering Project (Energy Commission, 2007).

[10] Linear extrapolation of natural gas prices. Source data from U.S. Energy Information Agency.

[11] Wartsila Technical Specifications for 50DF Engine: http://www.wartsila.com/

[12] National Renewable Energy Laboratory, Jobs and Economic Development Impact Natural Gas model customized to Humboldt County (SERC 2011).

Table 43: Technical and Economic Assumptions for the Wind Submodel

Technology	Wind			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	400	MW	SERC (2005)
	Current Day	~0	MW	
	Minimum 2030	0	MW	
	Maximum 2030	250	MW	
Production Characteristics	Date Sources	Modeled hourly wind farm output from NREL Western Wind Dataset		
	Capacity Factor	27	%	
Fixed Costs	Capital	2107	$/kW	JEDI[13]
	Operations	24	$/(kW*year)	
Variable Costs	Operations	0	$/MWh	
	Fuel	0	$/MWh	
Lifetime	Economic lifetime	25	years	
Impact	Local Jobs	0.88, 0.15	jobs/MW (construction, operation)	JEDI[13]
	Economic Output	89, 23	$/kW (construction, operation)	
	GHG Emission	0	tCO2e/MWh	

Source: SERC Staff

[13] National Renewable Energy Laboratory, Jobs and Economic Development Impact model for wind default cost values for a 50MW project (SERC 2011).

Table 44: Technical and Economic Assumptions for the Wave Submodel

Technology	Wave			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	1000	MW	SERC (2005)
	Current Day	0	MW	
	Minimum 2030	0	MW	
	Maximum 2030	100	MW	
Production Characteristics	Date Sources	Observed Spectral Wave Data from NOAA Buoy[14] 46022		
	Capacity Factor	23	%	Model Simulation
Fixed Costs	Capital	2590	$/kW	KEMA (2009)
	Operations	36	$/(kW*year)	
Variable Costs	Operations	12	$/MWh	
	Fuel	0	$/MWh	
Lifetime	Economic lifetime	25	years	
Impact	Local Jobs	1.0, 9.2	jobs/MW (construction, operation)	SERC Staff[15]
	Economic Output	264, 831	$/kW (construction, operation)	
	GHG Emission	0	tCO2e/MWh	

Source: SERC Staff

[14] National Oceanic and Atmospheric Administration, National Data Buoy Center -- Buoy 46022: http://www.ndbc.noaa.gov/station_page.php?station=46022

[15] Wave Economic Impact Assessment Model (SERC 2011).

Table 45: Technical and Economic Assumptions for the Biomass Submodel

Technology	Biomass			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	225	MW	SERC (2005)
	Current Day	61	MW	
	Minimum 2030	61	MW	
	Maximum 2030	225	MW	
Production Characteristics	Data Sources	Observed production from Fairhaven Power Plant		
	Capacity Factor	68	%	Model simulation
Fixed Costs	Capital	3450	$/kW	SERC Staff[16]
	Operations	160	$/(kW*year)	Klein (2010)
Variable Costs	Operations	10	$/MWh	
	Fuel	32	$/MWh	Hackett (2010)
Lifetime	Economic lifetime	25	years	
Impact	Local Jobs	2.5, 2.0	jobs/MW (construction, operation)	SERC Staff[17]
	Economic Output	494, 376	$/kW (construction, operation)	
	GHG Emission	0.006	tCO2e/MWh	Gas co-fire[18]

Source: SERC Staff

[16] Average of various recent authoritative studies circa 2008-10 (Klein, 2010; Lazard, 2008; E3, 2008).

[17] Biomass Impact Assessment Model (SERC 2011).

[18] Based on production data for Fairhaven biomass power plant where natural gas co-fire is occasionally used (Marino, 2010).

Table 46: Technical and Economic Assumptions for the Hydropower Submodel

Technology	Hydropower			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	60	MW	Oscar Larson & Assoc. (1982)
	Current Day	10.4	MW	SERC (2005)
	Minimum 2030	10.4	MW	
	Maximum 2030	35	MW	
Production Characteristics	Data Sources	Production data for Matthews Dam (HBMWD, 2010), production data for Zenia Power (Burgess, 2010), rainfall data from NOAA.		
	Capacity Factor	59	%	Model simulation
Fixed Costs	Capital	4500	$/kW	SERC Staff[19]
	Operations	124	$/(kW*year)	HBMWD (2010)
Variable Costs	Operations	0	$/MWh	
	Fuel	0	$/MWh	
Lifetime	Economic lifetime	40	years	SERC Staff[20]
Impact	Local Jobs	4.9, 1.1	jobs/MW (construction, operation)	SERC Staff[20]
	Economic Output	1179, 111	$/kW (construction, operation)	
	GHG Emission	0	tCO2e/MWh	

Source: SERC Staff

[19] Based on data obtained from various sources (OOE, 2003; KEMA, 2009; Burgess, 2010).

[20] River Hydropower Impact Assessment Model (SERC 2011).

Table 47: Technical and Economic Assumptions for the Photovoltaic Submodel

Technology	Photovoltaic			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	4.4	kWh/m²/day	NREL (2010)
	Current Day	1.1	MW	Energy Commission (2010b)
	Minimum 2030	1.1	MW	
	Maximum 2030	10	MW	
Production Characteristics	Data Sources	National Solar Radiation Database (NREL, 2010).		
	Capacity Factor	14	%	Model simulation
Fixed Costs	Capital	9090	$/kW	JEDI[21]
	Operations	11	$/(kW*year)	
Variable Costs	Operations	0	$/MWh	
	Fuel	0	$/MWh	
Lifetime	Economic lifetime	20	years	
Impact	Local Jobs	16, 0.1	jobs/MW (construction, operation)	JEDI[21]
	Economic Output	1460, 6.3	$/kW (construction, operation)	
	GHG Emission	0	tCO2e/MWh	

Source: SERC Staff

[21] National Renewable Energy Laboratory, Jobs and Economic Development Impact model for Solar PV, customized for Humboldt County. Assumes 20 percent large commercial (2 100kw systems), 15 percent small commercial (6 25kw systems), 5 percent residential new construction (17 3kw systems), and 60 percent residential retrofit (200 3 kw systems). The cost data are a weighted average cost for the systems specified.

Table 48: Technical and Economic Assumptions for the Import/Export Submodel

Technology	Import/Export			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	unlimited		
	Current Day	~60	MW	PG&E (2005)
	Minimum 2030	60	MW	
	Maximum 2030	250	MW	
Production Characteristics	Data Sources	Assumed to be available for import or export any hour of the year.		
	Capacity Factor	Variable	%	Model simulation
Fixed Costs	Capital	3000	$/kW	PG&E (2005)
	Operations	0	$/(kW*year)	
Variable Costs	Operations	0	$/MWh	
	Fuel	Variable	$/MWh	SERC Staff[22]
Lifetime	Economic lifetime	80	years	
Impact	Local Jobs	N/A	jobs/MW (construction, operation)	Data not available
	Economic Output	N/A	$/kW (construction, operation)	Data not available
	GHG Emission	0.36	tCO2e/MWh	E3 GHG Tool for Buildings[23]

Source: SERC Staff

[22] Hourly data estimated from California Independent System Operators locational marginal pricing for "Humboldt Zone" (CAISO, 2010).

[23] Energy, Environment, and Economics Greenhouse Gas Tool for Buildings: http://www.ethree.com

Table 49: Technical and Economic Assumptions for the Pumped Hydro Storage Submodel

Technology	Pumped Hydro Storage			
Sector	Electric Power Generation			
			Units	Source/ Justification
Magnitude	Total Resource	Undetermined		
	Current Day	0	MW	
	Minimum 2030	0	MW	
	Maximum 2030	25	MW	
Production Characteristics	Data Sources	Assumed to be available for discharge/charge any hour of the year given that stored energy is available/vacant respectively.		
	Round trip efficiency	78	%	Peterson (2008)
Fixed Costs	Capital	1250	$/kW	Klein (2008)
	Operations	65	$/(kW*year)	
Variable Costs	Operations	20	$/MWh	
	Fuel	0	$/MWh	
Lifetime	Economic lifetime	30	years	
Impact	Local Jobs	N/A	jobs/MW (construction, operation)	Data not available
	Economic Output	N/A	$/kW (construction, operation)	Data not available
	GHG Emission	0	tCO2e/MWh	

Source: SERC Staff

D.7 References

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ATTACHMENT I:
PG&E Interconnection Feasibility Study Plan

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Interconnection Feasibility Study Plan

Generation Interconnection

Humboldt County Renewables Project

Pacific Gas and Electric Company

WE DELIVER ENERGY.

February 11, 2011

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1. Introduction

Pacific Gas and Electric Company (PG&E) is participating in the Redwood Coast Energy Authority's (RCEA) Exploratory Project under the California Energy Commission (CEC) Renewable-based Energy Secure Communities (RESCO) Grant Program.

The Schatz Energy Research Center of the Humboldt State University requested that PG&E complete an Interconnection Feasibility Study (FS) to evaluate the transmission impacts of the proposed Humboldt County Renewables Project (Project) assuming a projected year 2030 peak electric loading condition. Scenario 1 of the Project consists of nine (9) proposed new generation facilities in Humboldt County with a total generation output of 253 MW.

Table 1-1: Scenario 1 New Generation Projects

Technology	Max MW	Location Description
Wind	50	Bear River Ridge
Wind	75	Bear River Ridge
Biomass	40	Samoa
Biomass	15	Willow Creek
Biomass	15	Garberville
Hydro	8	Maple Creek
Hydro	5	Hoopa Valley
Storage – Pumped Hydro	15	Ruth Lake
Wave	30	Samoa
Total New Generation	253	

The FS will identify:

- Transmission system impacts caused solely by the addition of the Project;
- System reinforcements necessary to mitigate any adverse impacts of the Project under various system conditions; and
- Facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility.

The Schatz Energy Research Center requested to perform the peak studies using a Humboldt area load of 253 MW, which is representative of the year 2030 winter peak. Typically, as required by the North American Reliability Corporation (NERC) reliability standards, PG&E's transmission planning studies focus on a 10 year planning horizon for long term studies to only identify marginal conditions that may have longer lead-time solutions. Therefore, the FS will only be a preliminary evaluation of the feasibility and the magnitude of the system impacts resulting from the proposed generation interconnection with the PG&E transmission system.

2. Schedule

Table 2-1 shows the milestones/schedules associated with the study.

Table 2-1: Study Schedule

Task	Milestone Description	Target Date
1	PG&E issues Interconnection Feasibility Study Plan	February 14, 2011
2	PG&E issues results to Humboldt County	March 2, 2011

3. Cost Estimates

The FS will provide a list of required facilities with a non-binding good faith estimate of cost responsibility of the facilities necessary to interconnect the Project. These costs have no associated degree of accuracy and are provided for informational purpose only.

4. Project and Interconnection Information

Scenario 1 of the Project includes nine new generation facilities. The facilities and the proposed interconnection points are summarized in Table 4-1.

Table 4-1: Scenario 1 New Generation Projects

Technology	Max MW	Location Description	Proposed Point of Interconnection
Wind	50	Bear River Ridge	Rio Dell Substation 60 kV Bus
Wind	75	Bear River Ridge	Rio Dell Substation 60 kV Bus
Biomass	40	Samoa	Fairhaven Substation 60 kV Bus
Biomass	15	Willow Creek	Willow Creek Substation 60 kV Bus
Biomass	15	Garberville	Garberville Substation 60 kV Bus
Hydro	8	Maple Creek	Maple Creek Substation 60 kV Bus
Hydro	5	Hoopa Valley	Hoopa Substation 60 kV Bus
Storage – Pumped Hydro	15	Ruth Lake	Low Gap Substation 115 kV Bus
Wave	30	Samoa	Fairhaven Substation 60 kV Bus

Figure 5-1 provides the map for the Project and the transmission facilities in the vicinity.

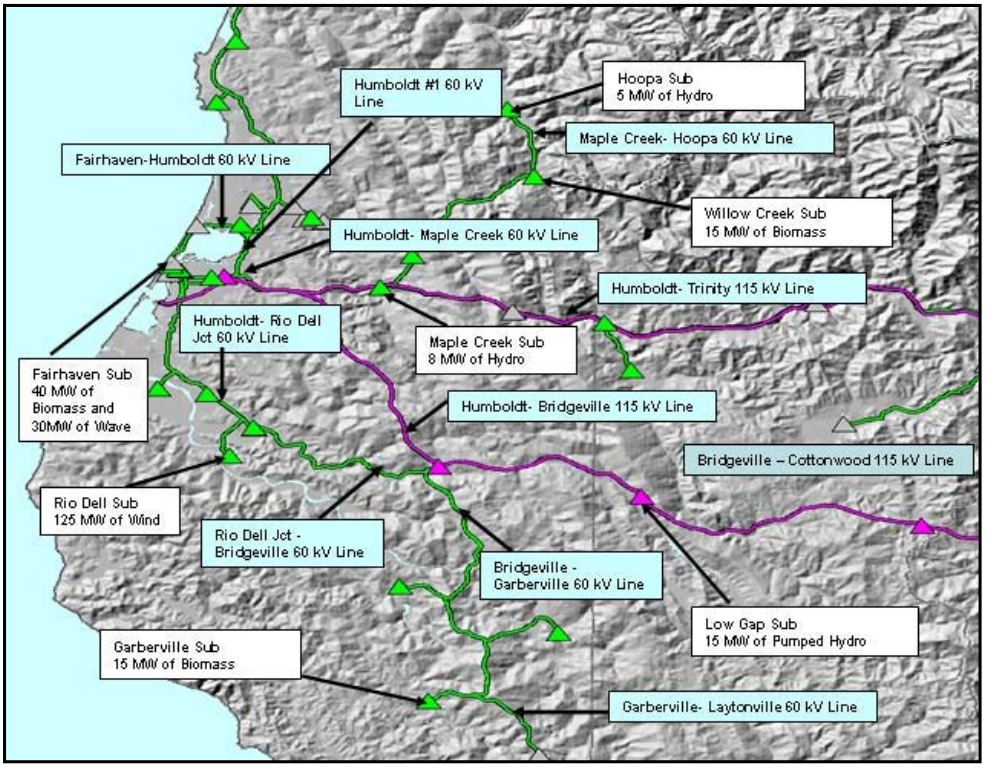

Figure 5-1: Vicinity Map

5. Study Assumptions

PG&E will conduct the FS under the following assumptions:

1) The total new generation output of the Project to the PG&E transmission system is 253 MW. New generation facilities will be modeled as shown in Table 5-1 with the full MW output at each location:

Table 5-1: Scenario 1 New Generation Projects

Max MW	Proposed Point of Interconnection
50	Rio Dell Substation 60 kV Bus
75	Rio Dell Substation 60 kV Bus
40	Fairhaven Substation 60 kV Bus
15	Willow Creek Substation 60 kV Bus
15	Garberville Substation 60 kV Bus
8	Maple Creek Substation 60 kV Bus
5	Hoopa Substation 60 kV Bus
15	Low Gap Substation 115 kV Bus
30	Fairhaven Substation 60 kV Bus

2) This study will take into account the planned generating facilities in PG&E's service territory that are in the California Independent System Operator Corporation (CAISO) Generation Interconnection Queue in the vicinity of the Project. In addition, all CAISO approved PG&E transmission projects that will be operational by 2020 will also be included.

3) As requested by the Schatz Energy Research Center, the load Humboldt area load to be studied is 253 MW and it represents the winter peak loading condition for the year 2030. The study will utilize a 2020 Winter Peak Base Case incorporating the year 2030 load as requested.

Note: Based on current observed lower load trends, the Humboldt area load may not reach the projected levels being assumed for the year 2030.

6. Power Flow Study Base Cases

Power flow analyses will be performed to ensure that PG&E's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results to these power flow analyses will serve as documentation that an evaluation of the reliability impact of new generation facilities and their connections on interconnected transmission systems is performed. If a NERC reliability deficiency exists as a result of this new generation interconnection, PG&E will identify the problem and develop appropriate transmission solutions to comply with NERC reliability standards.

Two (2) power flow base cases will be used to evaluate the transmission system impacts of this interconnection. While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

PG&E cannot guarantee that the Project:

a) can operate at maximum rated output 24 hours a day, year round, without system impacts; nor

b) will not have system impacts during the times and seasons not studied in the FS.

The following power flow base cases will be used for the analysis and FS:

- 2020 Winter Peak Base Case:

  Power flow analysis will be performed using PG&E's 2020 Winter Peak Base Case (in General Electric Power Flow format). This base case was developed from PG&E's 2010 base case series and has a 1-in-10 year adverse weather load level for PG&E's Coastal areas.

- 2020 Off-Peak Base Case:

  Power flow analysis will also be performed using PG&E's 2020 Off-Peak Base Case (in General Electric Power Flow format) to evaluate potential congestion on transmission facilities during the Off-Peak system conditions.

These base cases will model all CAISO approved PG&E transmission projects that would be operational by 2020. The planned PG&E system additions and upgrades are summarized in Table 6-1.

Table 6-1: Planned PG&E System Additions and Upgrades

Project
Fulton - Fitch Mountain 60 kV Line Reconductoring
Garberville Reactive Support
Humboldt - Harris 60 kV Reconductoring
Humboldt 115/60 kV Transformer Replacements
Humboldt Reactive Support
Maple Creek Reactive Support
Mendocino Coast Reactive Support

The base cases will also include all proposed generation projects that in the CAISO Generation Interconnection Queue in the vicinity of the Project and their associated identified network upgrades. However, some generation projects that are electrically far from the Project will be either turned off or modeled with reduced generation to balance the loads and resources in the power flow model. The major generation projects included and the associated network upgrades are summarized below in Table 6-2 and Table 6-3, respectively.

Table 6-2: Proposed Humboldt Area Generation Interconnection Projects

CAISO Queue	Point of Interconnection	Fuel	Max MW	Commercial Operation Date
38	Humboldt Power Plant Substation	Natural Gas	146.4	9/30/2010
212	Rio Dell Substation 60 kV bus	Wind	50	12/15/2013
472	Ultra Power 60 kV Tap Line	Biomass	13.8	4/23/2010
		Total	210.2	

Table 6-3: Network Upgrades for Proposed Generation Projects

Project
Reconductor Humboldt Bay - Rio Dell Jct 60 kV Line
Reconductor Rio Dell 60 kV Tap Line
Reconductor Humboldt Bay - Eureka 60 kV Line
Reconductor Humboldt - Humboldt Bay #2 60 kV Line

7. Study Scope

The FS will determine the impact of the Project on the PG&E transmission system. The specific studies to be conducted are outlined below:

7.1 Steady State Power Flow Analysis

The CAISO controlled-grid Reliability Criteria, which incorporates the Western Electricity Coordinating Council (WECC) and NERC planning criteria, will be used to evaluate the impact of the Project on the PG&E transmission system.

Power Flow analysis will be performed using the base cases described in Section 6. These base cases will be used to simulate the impact of the Project during normal (CAISO Category "A") operating conditions as well as during single (CAISO Category "B") and selected multiple (CAISO Category "C") contingency conditions. The study will cover the transmission facilities within PG&E's Humboldt and North Coast Areas.

The types of contingencies to be evaluated under each category are summarized below Table 7-1.

Table 7-1: Summary of Planning Standards

Contingencies	Description
CAISO Category "A"	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages for the transmission lines and generators.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category "C" contingencies will be considered for this study, it is impractical to evaluate all the CAISO Category "C" contingencies. For this reason, select critical Category "C" contingencies (C1 – C9) will be evaluated as part of this study.

7.2 Reactive Power Deficiency Analysis

With the generation project included in the system model, CAISO Category "B" and "C" contingencies will be analyzed to identify any reactive power deficiency:

- Whether the results show voltage drops of 5% or more from the pre-Project levels, or
- Whether the results fail to meet applicable voltage criteria.

A post-transient power flow analysis will be performed, if deemed necessary, after considering the network topology or power transfer paths involved when a significant amount of power transfer occurs.

8. Technical Requirements

The PG&E Interconnection Handbook explains the technical requirements for interconnection of loads and generators to PG&E's transmission system. The Interconnection Handbook documents facility connection requirements to the PG&E system as required in NERC Standard FAC-001-0. They are based on applicable FERC and CPUC rules and tariffs (e.g., Electric Rules 2, 21 and 22), as well as accepted industry practices and standards. In addition to providing reliability, these technical requirements are consistent with safety for PG&E workers and the public.

The PG&E Interconnection Handbook applies to Retail and Wholesale Entities, which own or operate generation, transmission, and end user facilities that are physically connected to, or desire to physically connect to PG&E's electric system. All technical requirements described or referred to in the Handbook apply to new or re-commissioned Generation Facilities. The Generation Interconnection Handbook comprising sections G-1 through G-5 applies to Generation Entities.

PG&E has established standard operating, metering and equipment protection requirements for loads and generators. The Interconnection Handbook covers such requirements for all transmission-level load and generation entities wishing to interconnect with PG&E's electric system. Additional, project-specific requirements may apply.

The PG&E Interconnection Handbook includes, but is not limited to such operating requirements as the following:

- The Project must be able to meet the power factor requirements of 90 percent lagging and 95 percent leading.

- The Project must have Automatic Voltage Regulation (AVR) and be able to maintain the generator voltage under steady-state conditions within ±0.5 percent of any voltage level between 95 percent and 105 percent of the rated generator voltage.

Generators must also meet all applicable CAISO, NERC, and WECC standards. NERC and WECC standards include, but are not limited to such requirements as the following:

- The Project must be able to remain on line during voltage disturbances up to the time periods and associated voltage levels as required by the WECC Low Voltage Ride Through (LVRT) standards that are in-line with FERC Order No. 161-A. The WECC LVRT standard is available on the WECC web site at:

  http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Voltage%20Ride%20Through%20White%20Paper.pdf

- Currently NERC is working on a Voltage Ride Through standard, PRC-024-1, that would be applicable to all generators interconnecting to the transmission grid. Until PRC-024-1 is effective, PG&E and the CAISO will require that all generators comply with the existing WECC LVRT requirements. The PRC-024-1 standard Draft 1 can be found on the NERC web site at

  http://www.nerc.com/docs/standards/sar/PRC-024-1_Draft1_2009Feb17.pdf

All generators must satisfy the requirements of the PG&E's Interconnection Handbook and meet all applicable CAISO, NERC, and WECC standards. PG&E will not agree to interconnect any new generators unless all technical and contractual requirements are met.

The interconnecting customer should be aware that the information in the PG&E Interconnection Handbook is subject to change. Parties interconnecting to the PG&E electric system should verify with their PG&E representative that they have the latest versions. The PG&E Interconnection Handbook is available on the PG&E web site at:

http://www.pge.com/about/rates/tariffbook/ferc/tih/

Pacific Gas and Electric Company.

WE DELIVER ENERGY.™

Feasibility Study Agreement

The Schatz Energy Research Center of the Humboldt State University has reviewed the Feasibility Study Plan for interconnection of the Humboldt County Renewables Project to PG&E's transmission system in Humboldt County, State of California, and agrees with the proposed plan.

Dated this _____ day of February, 2011

Schatz Energy Research Center of the Humboldt State University:

BY: _____
(Signature)

_____
(Type or Print Name)

MAILING ADDRESS:

_____

_____

_____

_____

ATTACHMENT II:
PG&E Interconnection Feasibility Study Results

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Humboldt County RESCO - Interconnection Feasibility Study

Generation Interconnection

Additional Information Request

Pacific Gas and Electric Company

WE DELIVER ENERGY.

June 10, 2011

Pacific Gas and Electric Company (PG&E) is participating in the Redwood Coast Energy Authority's (RCEA) Exploratory Project under the California Energy Commission (CEC) Renewable-based Energy Secure Communities (RESCO) Grant Program.

In March 2011, PG&E completed an Interconnection Feasibility Study (FS) to evaluate the transmission impacts of the proposed Humboldt County Renewables Project (Project) assuming a projected year 2030 peak electric loading condition.

Following completion of the FS, the Schatz Energy Research Center of the Humboldt State University requested that PG&E provide additional support by responding to the following questions:

1. Provide background narrative on the Humboldt County transmission system. Identify weak points (e.g., substations) and structural weaknesses (e.g., 60 kV as the main system voltage) and discuss the implications for shifting from being a load pocket to a generation pocket.
2. Provide first order cost estimates for system upgrades that would enable RESCO generators to meet NERC requirements.
3. Identify key bottlenecks in the system and provide recommendations on key upgrades that would be most cost-effective in enabling the build-out of future renewable generation. Also, identify geographic areas that are particularly problematic for adding new generation.
4. Explain whether or not the various system upgrades would be considered “Network Upgrades” according to CAISO and whether or not the interconnection customer would be repaid the cost of associated Network Upgrades over a five-year period commencing on the Commercial Operation Date of their newly installed generation.

Responses to the above questions and supporting information are provided in this document.

1. **Provide background narrative on the Humboldt County transmission system. Identify weak points (e.g., substations) and structural weaknesses (e.g., 60 kV as the main system voltage) and discuss the implications for shifting from being a load pocket to a generation pocket.**

Background

Electric customers in the Humboldt Area are served by the Pacific Gas and Electric Company's network of 115 kV and 60 kV transmission lines. The Humboldt electrical system receives its power primarily from the PG&E's Humboldt Generating Station and is connected to Mendocino and Cottonwood sources through the Bridgeville-Garberville and Garberville-Laytonville 60 kV lines respectively and Bridgeville – Cottonwood and Trinity – Cottonwood 115 kV Lines. The 115 kV lines from Cottonwood are over 100 miles long and the 60 kV lines from Trinity and Mendocino are 55 and 80 miles long, respectively. Electric customers within the Humboldt area are mainly served by the Company's network of 60 kV transmission lines and distribution substations

The Humboldt transmission system is currently operated as a balanced system of internal generation with some imports and has not been designed to withstand exporting large amounts of power outside of its system. The system has one major 115 kV loop to transport power throughout the Humboldt system while the load is served primarily through the 60 kV transmission system. Generally, the 60 kV transmission system is networked together and is comprised of long circuits with enough capacity to serve the local area load. Consequently, as the power flow analysis with the proposed generation shows, the 60 kV transmission system is not adequate to transport mid to large amounts of generation and would be considered the main limitation or system weakness in converting Humboldt into a generation exporting area. Excess generation in this system results in many normal overloads of the 60 kV system and during contingencies, the same amount of generation needs to be pushed through the rest of the 60 kV circuits causing even more severe overloads. Ideally, it would make sense to add new generation close to a major transmission line in order to transport the electric power, however if this preferred route was compromised for any reason the rest of the networked 60 kV system would have to pick up the flow. This again would lead to major overloads throughout the entire Humboldt system. Another major limitation for interconnecting large amounts of generation in Humboldt is the fact that the resulting extremely high flows of electric power on the 60 kV transmission system cause heavy reactive power losses on the lines due to the surge impedance line characteristics. This issue is of concern because it may lead to poor system reliability and possible voltage instability.

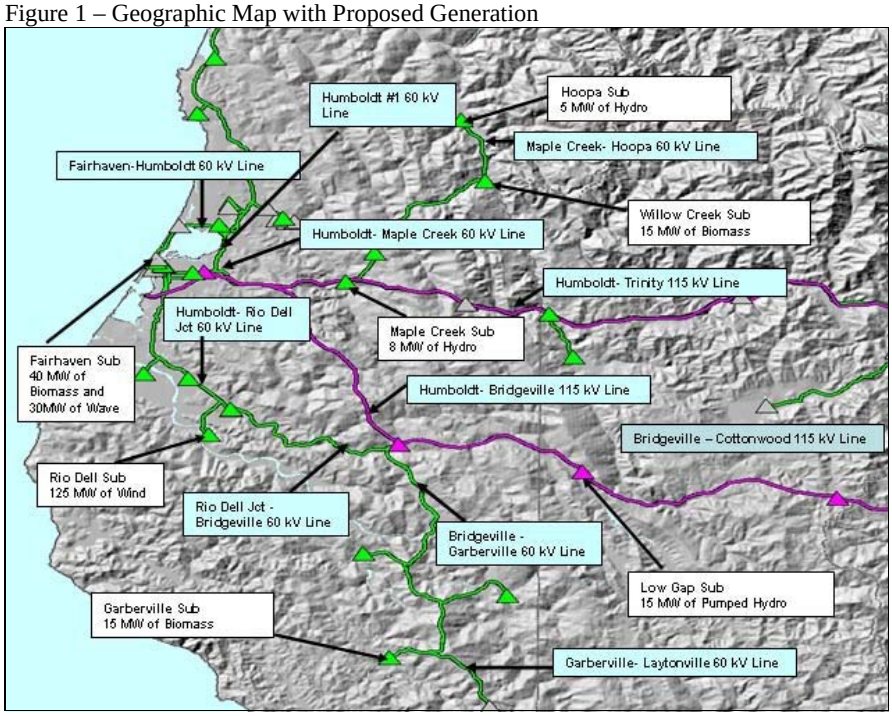
Power Flow Analyses – Identifying System Constrains

The power flow analysis completed evaluated the transmission impacts of adding 9 renewable generating facilities (totaling 253 MW) in Humboldt County by the year 2030. These generating facilities would mainly be interconnected to the 60 kV system in the Humboldt area as indicated in the table below. A geographic map indicating the actual locations is also presented.

Table 1 – Proposed Generation

Technology	Max MW	Location Description	Proposed Point of Interconnection
Wind	50	Bear River Ridge	Rio Dell Substation 60 kV Bus
Wind	75	Bear River Ridge	Rio Dell Substation 60 kV Bus
Biomass	40	Samoa	Fairhaven Substation 60 kV Bus
Biomass	15	Willow Creek	Willow Creek Substation 60 kV Bus
Biomass	15	Garberville	Garberville Substation 60 kV Bus
Hydro	8	Maple Creek	Maple Creek Substation 60 kV Bus
Hydro	5	Hoopa Valley	Hoopa Substation 60 kV Bus
Storage – Pumped Hydro	15	Ruth Lake	Low Gap Substation 115 kV Bus
Wave	30	Samoa	Fairhaven Substation 60 kV Bus

Figure 1 – Geographic Map with Proposed Generation



The study took into account all existing and planned generating facilities in PG&E's service territory in the California Independent System Operator Corporation (CAISO) Generation Interconnection Queue within the vicinity of the Project along with identified associated network upgrades. In total, the generation assumed in place in Humboldt before adding the proposed 9 projects is roughly 280 MW. When adding the proposed generating projects, the Humboldt area represented a total of 533 MW of generating capacity.

In addition for this study, all CAISO approved PG&E transmission projects operational by 2020 were also included and the Humboldt area load was adjusted to 253 MW to represent the winter peak loading condition for the year 2030.

Simply reviewing the load vs. generation amounts assumed in the study, the Humboldt area would be exporting 280 MW of electricity onto the rest of the PG&E system. As expected, given the limitation of the transmission system, numerous thermal violations were observed during normal system conditions and under different contingency events. Below is a summary of the facility overloads identified and that PG&E developed potential solutions for.

Category A – Thermal Problems
1. Bridgeville 115/60 kV Transformer Bank 1
2. Bridgeville-Garberville 60 kV Line (Bridgeville-Fruitland Jct)
3. Rio Dell 60 kV Tap Line (Rio Dell-Scotia Tap)
4. Rio Dell 60 kV Tap Line Scotia Tap-Rio Dell Jct
5. Rio Dell Jct-Bridgeville 60 kV Line (Rio Dell Jct-Carlotta)
6. Rio Dell Jct-Bridgeville 60 kV Line (Carlotta-Swains Flat)
7. Rio Dell Jct-Bridgeville 60 kV Line (Swains Flat-Bridgeville)

Category B – Thermal Problems
8. Bridgeville-Cottonwood 115 kV Line (Low Gap-Bridgeville)
9. Bridgeville-Cottonwood 115 kV Line (Wildwood-Cottonwood)
10. Bridgeville-Garberville 60 kV Line (Fruitland Jct-Fort Seward Jct)
11. Bridgeville-Garberville 60 kV Line (Fort Seward Jct-Garberville)
12. Essex Jct-Arcata-Fairhaven 60 kV Line (Arcata Jct 2-Fairhaven)
13. Fairhaven-Humboldt 60 kV Line (Arcata Jct 2-Humboldt)
14. Fairhaven-Humboldt 60 kV Line (Arcata Jct 2-Sierra Pacific)
15. Fairhaven-Humboldt 60 kV Line (Sierra Pacific-Fairhaven)
16. Humboldt Bay-Humboldt #1 60 kV Line (Humboldt-Humboldt Jct)
17. Humboldt Bay-Rio Dell Jct 60 kV Line (Eel River-Newburg)
18. Humboldt Bay-Rio Dell Jct 60 kV Line (Humboldt Bay-Eel River)
19. Humboldt Bay-Rio Dell Jct 60 kV Line (Newburg-Rio Dell Jct)
20. Humboldt-Bridgeville 115 kV Line
21. Humboldt-Trinity 115 kV Line
22. Humbolt Bay-Eureka 60 kV Line
23. Trinity-Cottonwood 115 kV Line (Jessup Tap-Cottonwood)

Category C – Thermal Problems
24. Trinity-Maple Creek 60 kV Line (Big Bar-Hyampom Jct)
25. Trinity-Maple Creek 60 kV Line (Maple Creek-Ridge Cabin)
26. Trinity-Maple Creek 60 kV Line (Ridge Cabin-Hyampom Jct)

Note that the power flow analysis performed did not consider the potential issues at the California-Oregon-Intertie (COI). The injection of 280 MW from the Humboldt area could potentially cause reliability and/or congestion issues that may limit the amount of generation that can be interconnected in the Humboldt area or at least affect the amount of hours when the full

capacity can be accepted into the system without first upgrading COI. These potential issues would be identified when a more detailed engineering study is performed as part of a formal interconnection request.

2. Provide first order cost estimates for system upgrades that would enable RESCO generators to meet NERC requirements.

As a registered Transmission Planner (TP), PG&E must ensure that its transmission system remains in full compliance with the North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 at all times. To supplement the FS, PG&E developed transmission reinforcement alternatives that address all identified NERC reliability deficiencies in the Humboldt area electric transmission system resulting from the new generation interconnection. The costs estimates developed for the identified system reinforcements are based on per unit cost estimates and are non-binding.

Three alternatives were developed and studied to ensure that the identified transmission system issues are corrected. The first alternative consists of simply upgrading the facilities identified to have thermal or voltage problems, by replacing conductor and substation equipment such as transformers with higher capacity equipment and adding voltage support equipment. The second alternative involves a combination of facilities upgrades and conversion of operating voltage of certain parts of the Humboldt 60 kV system to 115 kV and 230 kV voltage operation. The third alternative considered entails building new 230 kV lines and associated facilities along with local system reinforcement as necessary. Analysis of the cost and system impacts, conclude that the third alternative, new 230 kV lines, is preferred as it provides the higher level of reliability and system integrity to the Humboldt transmission system at the lowest cost. The three alternatives are further discussed below.

Alternative 1 –Replacement of Overloaded Facilities

The first alternative entails reconductoring of the majority of the lines within the Humboldt transmission system as well as the existing tie lines to Mendocino and Cottonwood. A total of 484 miles of line are proposed to be reconductored. However, simple reconductoring does not mitigate the voltage violations caused by heavy reactive power loses in the lines due to the high electric power flow on low voltage lines. To address the high reactive power loses issue, this alternative includes installation of a large amount of voltage support across the Humboldt transmission system to meet voltage criteria. If this alternative were to be selected, further reactive and voltage stability studies would need to be performed to ensure local transmission grid integrity.

This alternative is estimated to cost about $940 Million. This alternative is not recommended as it very costly and does not improve system reliability, in fact, it can make the system more vulnerable to operate.

Alternative 2 – Partial Voltage Conversion and Reconductor

This alternative attempts to utilize and maximize the existing infrastructure by converting portions of the existing transmission system to higher voltage operation. The alternative entails

converting the entire southern portion of the Humboldt system from 60 kV to 115 kV operation as well as converting the inner 60 kV loops that transfer power throughout the Humboldt area to 115 kV operation. The existing 115 kV transmission lines between Humboldt and Cottonwood Substations are also converted to 230 kV operation to withstand the large amount of generation being exported.

This alternative requires a total of 427 miles of transmission line conversion to higher voltage, 92 miles of reconductoring, 6 transformer installations or replacement, voltage conversion of 25 substations and building 3 new substations. This alternative is estimated cost about $1 Billion.

Alternative 3 – New 230 kV Facilities

This alternative consists of building a new 230 kV Substation at Rio Dell Jct and building a 95-mile 230 kV double circuit tower line from Rio Dell Jct to Cottonwood 230 kV Substation. Rio Dell Jct was chosen because the largest generation is proposed at this location. The line terminates at Cottonwood Substation because that is the closest 230 kV Substation to the Humboldt area. .

This alternative considers the 253 MW of proposed renewable generation at the given locations. If the amounts and/or location for the generation changes, this alternative would need to be expanded or revised to accommodate such changes. This alternative is preferred in comparison to the other alternatives studied because it allows generation in Humboldt to be connected without compromising the existing transmission system. In addition, this alternative provides the most effective way to address identified thermal and voltage violations while requiring the least amount of overall upgrades to the existing system to obtain reliability and maintain system integrity. This alternative is estimated to cost about $260 Million.

A detailed list of required facility upgrades along with non-binding cost estimates for each alternative are provided in the following tables. The costs provided are for informational purposes only. These were derived using typical per unit costs and have no associated degree of accuracy.

Furthermore and as indicated before, it is important to note that the power flow study performed and the alternatives and costs outlined above, do not account or consider limitations at the California-Oregon-Intertie (COI) that may exist now or at the time when this proposed renewable generation may develop. The injection of roughly 280 MW from the Humboldt area to the Cottonwood transmission system could potentially cause reliability or congestion issues that may limit the amount of generation that can be interconnected in the Humboldt area without any upgrades to the COI. Potential COI upgrades are unknown at this time and are not included in the costs provided. If any upgrades are required, these would be identified by detailed engineering studies when a formal interconnection request is submitted.

Table 2 – Alternative 1 Associated Work

Alternative 1 - Reconductoring, Voltage Support and Transformer Upgrades only			
Description	*Units*	*P.U. Costs*	*Total Costs*
Reconductor Bridgeville - Cottonwood 115 kV Line	86.4	1.5	129.6
Reconductor Bridgeville - Garberville 60 kV Line	36.1	1.5	54.1
Reconductor Rio Dell 60 kV Tap Line	5.8	1.5	8.7
Reconductor Rio Dell Jct - Bridgeville 60 kV Line	21.3	1.5	31.9
Reconductor Essex Jct - Arcata – Fairhaven 60 kV Line	16.1	1.5	24.1
Reconductor Arcata - Humboldt 60 kV Line	7.2	1.5	10.9
Reconductor Fairhaven - Humboldt 60 kV Line	15.3	1.5	22.9
Reconductor Humboldt Bay - Humboldt No.1 60 kV Line	8.1	1.5	12.1
Reconductor Humboldt Bay - Rio Dell Jct 60 kV Line	4.4	1.5	6.6
Reconductor Humboldt - Bridgeville 115 kV Line	30.3	1.5	45.4
Reconductor Humboldt - Trinity 115 kV Line	68.7	1.5	103.0
Reconductor Humboldt Bay - Eureka 60 kV Line	5.6	1.5	8.5
Reconductor Trinity - Cottonwood 115 kV Line	45.8	1.5	68.7
Reconductor Garberville - Laytonville 60 kV Line	40.0	1.5	60.0
Reconductor Humboldt - Eureka 60 kV Line	1.1	1.5	1.7
Reconductor Humboldt - Maple Creek 60 kV Line	13.9	1.5	20.9
Reconductor Trinity - Maple Creek 60 kV Line	61.1	1.5	91.7
Reconductor Trinity - Keswick 60 kV Line	30.5	1.5	45.7
Reconductor Cascade - Keswick 60 kV Line	7.2	1.5	10.8
Install New Bridgeville No.2 115/60 kV XFMR with higher ratings	1	7	7.0
Replace Cottonwood 230/115 kV No. 4 XFMR with higher capacity	1	10	10.0
Replace Cottonwood 230/115 kV No. 1 XFMR with higher capacity	1	10	10.0
Voltage Support required at various locations (low voltages throughout entire area)	8	20	160.0
Total Cost for Alternative			**944**
**Note - Reconductoring costs do not include pole replacements or any substation upgrades*			

Table 3 – Alternative 2 Associated Work

Alternative 2 - Voltage Conversion, Reconductoring and Transformer Upgrades only			
Description	*Units*	*P.U. Costs*	*Total Costs*
Convert Bridgeville - Garberville 60 kV to 115 kV Line	86.4	1.5	129.6
Convert Rio Dell 60 kV Tap 60 kV to 115 kV Line and reconductor	5.8	1.5	8.7
Convert Rio Dell Jct - Bridgeville 60 kV to 115 kV Line and reconductor	21.3	1.5	31.9
Convert Essex Jct. - Arcata - Fairhaven 60 kV Tap 60 kV to 115 kV Line	16.1	1.5	24.1
Convert Fairhaven - Humboldt 60 kV to 115 kV Line	15.3	1.5	22.9
Convert Humboldt Bay - Humboldt No.1 60 kV to 115 kV Line	8.1	1.5	12.1
Convert Humboldt Bay - Rio Dell Jct 60 kV to 115 kV Line	4.4	1.5	6.6
Convert Humboldt Bay - Eureka 60 kV to 115 kV Line	5.6	1.5	8.5
Convert Pacific Lumber (Scotia) 60 kV Tap to 115 kV	5.3	1.5	8.0
Convert Fruitland 60 kV Tap to 115 kV	4.3	1.5	6.4
Convert Fort Seward 60 kV Tap to 115 kV	7.6	1.5	11.5
Convert Humboldt - Maple Creek 60 kV to 115 kV Line	13.9	1.5	20.9
Convert Trinity - Maple Creek 60 kV to 115 kV Line	61.1	1.5	91.7
Convert Garberville - Layonville 60 kV to 115 kV Line	40.0	1.5	60.0
Convert Bridgeville - Cottonwood 115 kV to 230 kV Line	86.4	1.7	146.8
Convert Trinity - Cottonwood 115 kV to 230 kV Line	45.8	1.7	77.9

Alternative 2 - Voltage Conversion, Reconductoring and Transformer Upgrades only (cont.)			
Reconductor Willits - Laytonville 60 kV Line	23.4	1.5	35.1
Reconductor Humboldt - Trinity 115 kV Line	68.6	1.5	103.0
Replace Bridgeville 115/60 kV to 230/115 kV XFMR with higher capacity	1	7	7.0
Replace Cottonwood 230/115 kV No. 4 XFMR with higher capacity	1	10	10.0
Replace Cottonwood 230/115 kV No. 1 XFMR with higher capacity	1	10	10.0
Install New Trinity 230/115 kV XFMR	1	7	7.0
Install New Laytonville 115/60 kV XFMR	1	7	7.0
Install New Maple Creek 115 kV XFMR	1	7	7.0
Build New Trinity 230 kV Substation	1	13	13.0
Build New Laytonville 115 kV Substation	1	10.5	10.5
Build New Maple Creek 115 kV Substation	1	10.5	10.5
Convert following 60 kV Substations to 115 kV Substations:			
Kekawaka	1	4	4.0
Scotia	1	4	4.0
Q0212	1	4	4.0
Eel River	1	4	4.0
Newburg	1	4	4.0
Rio Dell Tap	1	4	4.0
Rio Dell	1	4	4.0
Carlotta	1	4	4.0
Pacific Lumber	1	4	4.0
Swains Flat	1	4	4.0
Fruitland	1	4	4.0
Fort Seward	1	4	4.0
Fairhaven	1	4	4.0
Eureka	1	4	4.0
Maple Creek	1	4	4.0
Arcata	1	4	4.0
Eel River	1	4	4.0
Garberville	1	4	4.0
Convert following 115 kV Substations to 230 kV Substations:			
Grouse Creek	1	6	6.0
Big Bar	1	6	6.0
Hyampom	1	6	6.0
Ridge Cabin	1	6	6.0
Low Gap	1	6	6.0
Forest Glen	1	6	6.0
Wildwood	1	6	6.0
Total Cost for Alternative			**1002**

Table 4 – Alternative 3 Associated Work

Alternative 3 - Build New DCTL 230 kV Line and Reconductor only			
Description	*Units*	*P.U. Costs*	*Total Costs*
Build New 230 kV Substation at Rio Dell	1	13	13.0
Reconductor Rio Dell 60 kV Tap	5.8	1.5	8.7
Build New DCTL Rio Dell - Cottonwood 230 kV Line	95	2.4	228.0
SPS	2	5	10.0
Total Cost for Alternative			**260**

Note: all upgrades are associated with Category B contingencies. Category C violations are mitigated by upgrades acquired for Category B. All costs are based in millions. Costs assume larger insulators, pole replacement, and conductor condition for voltage conversion. Land and permitting not included in this cost estimate.

3. Identify key bottlenecks in the system and provide recommendations on key upgrades that would be most cost-effective in enabling the build-out of future renewable generation. Also, identify geographic areas that are particularly problematic for adding new generation.

Bottlenecks and Recommendations

The key bottleneck identified in the Humboldt transmission system is the voltage level (mainly 60 kV) the system is currently operated at and the conductor sizes. The Humboldt transmission system is currently operated as a balanced system of internal generation with some imports and has not been designed to withstand exporting large amounts of power outside of its system. The 60 kV transmission system is not adequate to transport mid to large amounts of generation and would be considered the main limitation or system weakness in converting Humboldt into a generation exporting area. Excess generation in this system results in many normal overloads of the 60 kV system and during contingencies, the same amount of generation needs to be pushed through the rest of the 60 kV circuits causing even more severe overloads. In addition, large flows on low voltage lines cause heavy reactive power losses in the lines which can lead to voltage violations and potential grid voltage instability.

Since Humboldt County is not a densely populated area the amount of generation being proposed would indeed need an outlet onto the main transmission bulk system. Humboldt, being a self sustained system, does not rely heavily on power being imported in therefore the only major tie comes from Cottonwood. This arrangement is reliable and adequate for the current configuration of the system, but does not allow the system to become a generation exporting system. Ideally, as the alternative analysis shows, it would make sense to build new strategically located 230 kV lines that would enable the build-out of renewables and transport of the electric power. This transmission system reinforcement, while difficult to implement appears to be the most efficient and economic way to allow the Humboldt transmission system to export electric power from the proposed renewable generation.

4. **Explain whether or not the various system upgrades would be considered "Network Upgrades" according to CAISO and whether or not the interconnection customer would be repaid the cost of associated Network Upgrades over a five-year period commencing on the Commercial Operation Date of their newly installed generation.**

The CAISO Tariff defines Network Upgrades as "The additions, modifications, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distribution Upgrades."

As part of the CAISO Generation Interconnection Procedures (GIP) interconnection studies, Network Upgrades will be identified to mitigate any adverse transmission impacts as a result of the proposed generation facilities. Since the Project has not yet been studied in the CAISO process, it is difficult to determine the full scope of Network Upgrades needed to interconnect the Project. The required upgrades may be the same, more, or less than what is identified in this document. The results are highly dependent on higher-queued projects as well as the other proposed projects that will be studied in the cluster.

The financing of Network Upgrades is the responsibility of each Interconnection Customer up to their cost responsibility as assigned in the interconnection studies. Upon the Commercial Operation Date of the facility, the interconnection customer is entitled to repayment of its contribution to the cost of Network Upgrades. The repayment is made within a five-year period of the Commercial Operation Date and will include interest calculated in accordance with FERC regulations.