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Rethinking Electric Grid Design to Meet Beneficial Electrification and Enhanced Distributed Generation

A Portland Area Case Study

GridSolar, LLC
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Abstract

Maine's largest electric utility, Central Maine Power, has identified a need for improved reliability of its electric transmission grid in the greater Portland region and a solution for that need involves the construction of additional miles of 115 kV lines, new 34.5 kV substations and the reconductoring of a number of transmission circuits in the region. The total cost of the utility's proposed solution is in excess of $200 million.

Simultaneously, Maine and an increasing number of municipalities have adopted policies of achieving near-zero carbon economies by 2050. These carbon reduction objectives can only be achieved through the conversion of transportation, space heating and commercial and industrial processes from distillate fuels and natural gas to electricity. Such conversion is only useful to reducing carbon emissions to the extent that new renewable generation is developed on a scale sufficient to meet the increased electricity demands.

This study presents a first look at the new and very significant electricity demands each of these processes – what have come to be called beneficial electrification and deep decarbonization – will impose on the region's electric transmission and distribution grid. Our analysis and modeling show that for this geographically small urban region alone the former will result in a more than doubling of the total amount of electricity that will flow to customers on the grid and a three-fold increase in peak loads, while the latter will require the interconnection of thousands of distributed solar generation systems on the rooftops of residential, commercial and industrial buildings in the region. These are well beyond the capacity of the current electric grid in the region.

Together, beneficial electrification and deep decarbonization will require nothing short of a new electric grid – one that is redesigned and capable of handling much larger volumes of electricity, multi-direction electricity flows across the entire grid and information, communication and control capabilities to manage hundreds of thousands of discrete loads and generation points on the grid. This new redesigned grid will not result from the current transmission and distribution planning processes. These processes have led to proposed upgrades to achieve at best modest increases in reliability at a cost of over $200 million. Instead, Maine needs to develop new measures of electric grid performance and standards that will direct utilities to make investments that enable cities and states to achieve their zero-carbon futures within their established timeframes. Since the planning, design, development and commissioning cycle for transmission projects can exceed a decade, Maine is already behind the curve.

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Chapter 1 - Introduction and Overview

1.1 Project Origins

The origins of this project date back to August 2008, when Central Maine Power (CMP) proposed its Maine Power Reliability Project ("MPRP") to the Maine Public Utilities Commission ("MPUC").[1] The MPRP was a more than $1.5 billion upgrade to the state's high voltage transmission grid that CMP believed was necessary to meet federal electric grid reliability requirements. GridSolar argued that CMP's load assumptions were overstated and that the same degree of reliability could be achieved through the development of in-region distributed generation, energy conservation and demand management that could be called upon to support load in the event that components of the transmission system were out of service. GridSolar referred to these options collectively as "Non-Transmission Alternatives ("NTAs").[2]

The parties in the MPRP case reached a settlement that was adopted by the MPUC. A key part of the MPUC order carved out two sections of the CMP grid and components of the MPRP for specific study to determine whether NTA solutions could be fashioned that provided the same degree of reliability or better at a lower cost than the transmission options proposed in the MPRP. One of these areas is the Portland – South Portland region. This is the subject of an ongoing case at the MPUC – Docket No. 2011-00138.

CMP's initial filings in this case defined a variety of transmission solutions for the region. These solutions were reexamined in later CMP filings using updated load data and incorporating the full scope of the MPRP system build-out. Further activity in the case has been delayed as the parties are waiting for ISO New England (ISO-NE) to complete a long-awaited overall needs assessment update of the transmission grid for the entire State of Maine.

At the same time as these efforts were being undertaken, GridSolar has been focusing its attention on how the electric grid will need to be modified, restructured and expanded to

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[1] See Maine Public Utilities Commission, Docket No. 2008-00255.

[2] These are also frequently referred to in the industry as Non-Wires Alternatives or NWAs. We use the terms NTA and MWA interchangeably in this report.

accommodate two critical components of any solution to the problem of climate change and global warming. The first of these is what is called "beneficial electrification". Beneficial electrification is a term used to describe the conversion of key sectors of the economy, specifically transportation, space heating and commercial and industrial processes, to electricity from fossil fuels, including coal, natural gas and oil. The second is "deep decarbonization". Deep decarbonization is the elimination of fossil fuels in the generation of electricity through the development of renewable, zero-carbon generation plants and storage technologies.

Work that GridSolar's principals have done demonstrates that beneficial electrification in Maine will increase total electricity consumption by a factor of three and increase peak loads on the grid by a factor of five. Simultaneously, the expansion of distributed generation and specifically rooftop solar photovoltaic (PV) and battery storage devices will require upgrades to the electric grid that convert the grid into a full-scale power network capable of accommodating multi-directional power flows across all aspects of the grid. As we demonstrate in this report, such a grid will look very different from today's electric grid. In addition to significant changes in its physical layout and various component parts, the grid must allow for vastly expanded communication flows that effectively interconnect, monitor and control hundreds of thousands, if not millions, of generation, end-use equipment and storage across the system.

1.2 Project Development

GridSolar believes that the current methodologies used in grid planning and the standards defining measures of grid reliability are inadequate to meet the needs, requirements and demands of our future electric grids, and further, that if these current methodologies continue to guide the development of the electric grid, they will yield highly inefficient results. A decade ago, the ISO-NE planning processes led CMP to design grid upgrades to meet ten-year load forecasts projecting large increases in electricity loads. Maine and the rest of New England had been investing in energy conservation and was about to expand those efforts to encourage the adoption of new technologies such as LED lighting and variable-speed drives to reduce electricity consumption. These and related technologies were reducing electric demands at the same time that overall economic conditions were deteriorating. The result has been essentially zero load growth over the past decade in Maine (and across New England).

Today, the same forecast models and planning processes direct CMP to design grid upgrades based on static loads and minimal expansion of distributed generation systems. Yet, Maine (and the other New England states) is actively encouraging the conversion of residential households from oil heat to electric air-source heat pumps and is accommodating the adoption of electric vehicles through the development of public charging stations across the state. In addition, across the country we are seeing strong interest in and growth of rooftop solar PV systems, primarily related to the falling price of solar PV. While Maine has been slower than many states with respect to distributed solar PV, there is considerable pent-up demand for these systems, and we can expect to see their rapid growth and expansions over the next decade.

A second very important factor reinforcing the idea that the electric sector will undergo significant changes over the next two to three decades is that cities around the country, including Portland and South Portland, are committing to decarbonizing their economies. While these commitments are long on aspiration and short on strategy, they appear to be increasingly serious and likely to rely on the twin pillars of beneficial electrification and deep decarbonization through renewable generation development to accomplish their objectives. As noted earlier, very little progress can be made in either effort without accompanying changes to the electric grid.

GridSolar believes there is a unique opportunity to build upon the commitments of the cities of Portland and South Portland to become carbon free and to use the open docket at the MPUC. This docket can be used to focus on the transmission grid in the Portland region to identify inadequacies in current grid planning and design methodologies and to incorporate beneficial electrification and renewable distributed energy development as critical factors that will drive future electric grid requirements. GridSolar received strong support from the city managers of both cities and their sustainability departments for this concept, support that has been echoed by environmental and other interests in Maine. GridSolar brought this support and a proposal for funding to the so-called "E4 Group", made up on the Office of Public Advocate, the Conservation Law Foundation, the Acadia Center, the Industrial Energy Consumers Group and the Natural Resources Council of Maine.[3] The proposal was approved in late 2018. GridSolar began work on the project in January 2019.

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[3] GridSolar is also a member of the E4 Group, which takes its name from the section of the Settlement Agreement approved by the MPUC in the MPRP case.

1.3 Project Overview

This report is organized into eight chapters corresponding to the major components of the analysis and modeling performed. Chapter 2 describes the Portland Region, which for our purposes is defined by the structure of the electric grid and not by political boundaries. Chapters 3 and 4 utilize many of the same methodologies and present many of the same analyses used by Dr. Silkman in his 2019 "A New Energy Policy Direction for Maine: A Pathway to a Zero-Carbon Economy by 2050". In this report, our focus is more limited to only those buildings and activities located within the Portland Region. In addition, rather than the statewide aggregated approach used by Silkman, we have developed energy use at the building level to enable us to examine use from a geospatial perspective.

Chapter 3 focuses on current energy use within the region. We estimated four types of energy use – current electricity use, space heating (including domestic hot water), commercial and industrial processes and transportation. These uses are produced using a wide variety of fuels. We included electricity, heating oil, natural gas, propane, diesel and gasoline. Since we included electricity, we did not include any primary energy fuels used to generate that electricity. In addition, we did not include biomass. Biomass is a relatively small percent of total fuel used in the region. Rather than include it, we assumed that whatever biomass that is currently being used will continue to be used, since it is a zero-carbon, renewable fuel. Finally, we did not include any fuels used for aviation or marine use. We are not aware of any electrification technologies that are currently economically viable for these two sectors of the economy.

In Chapter 4, we assumed that all space heating, commercial and industrial processes and transportation (not including aviation and marine use) in the Portland Area are converted from their current fuels to electricity – what has come to be known as "beneficial electrification". Our focus is on the end-state – that is, the point in the future when 100% of this conversion has been accomplished. We assumed that there is no net change in the amount of energy used from today's current energy use to this point in the future, with one exception – we allowed for increased use of air conditioning in residential buildings that is enabled by the adoption of air source heat pumps to meet space heating requirements in these buildings. The net effect of beneficial electrification is a more than doubling of total electricity use and an increase in peak electricity use from 270 MW, which currently occurs during the summer months, to 1,086 MW, which occurs during the coldest winter months.[4] However, because of the efficiencies in energy use as a result of converting the transportation sector from internal combustion engines to electric motors and the space heating sector from boilers and furnaces to heat pumps, the total amount of energy consumed falls by 59%, from 34 trillion btu to 14.1 trillion btu.

Chapter 5 focuses on the development of renewable distributed energy generation in the Portland Area. Given the geography, urban and rural development patterns, underlying economics of generation technologies and political realities of this part of Maine, we identified rooftop solar PV as the only viable distributed generation technology.[5] Using city tax maps, GIS mapping capabilities, LiDAR (Light Detection And Ranging) data and weather data, we developed a model that allows the estimation of the rooftop solar PV capacity and generation potential of every building in the region. We used this model, along with certain parameters defining those rooftops where the installation of solar PV systems would be economic, to estimate the hourly solar generation from all buildings. We assumed that all viable rooftop solar PV installations could be interconnected to the electric grid at no cost to the solar PV owner for any upgrades upstream of its point of interconnection.

Chapter 6 combines the results of Chapters 4 and 5. We define the term "energy balances" to measure the difference between the use of electricity under beneficial electrification, as estimated in Chapter 4, and the generation of electricity from the full buildout of distributed rooftop solar PV, as estimated in Chapter 5. We calculated energy balances for the region, and for each electricity distribution circuit and transformer/substation in the electrical grid system in the region. In addition, we identified those circuits where the total solar PV generation is larger than interconnected loads and will result in reverse power flows, and we consider the role storage may play in this context. The magnitudes of these energy balances must be met by importing electricity from outside the region (up to 1,100 MW) and exporting electricity to outside the region (up to 550 MW).

Chapter 7 discusses the impacts beneficial electrification, deep decarbonization and the resulting energy balances at all levels of the electric grid have on electricity load forecasting

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[4] The percentage increases are lower for the Portland Region than for the State of Maine, as a whole. This is due in part to differences in the makeup of the economic base, smaller housing unit sizes (more apartments) and lower miles driven by car due to the density of the region.

[5] We recognize that ground-mounted distributed solar PV systems are likely to be built in the Portland region, especially in the less densely populated portions of the region. For simplicity, our analysis makes no changes in the physical landscape or building footprints in the Portland region. Accordingly, we did not include any ground-mounted solar PV.

methodologies and on the capacity and design of the electric grid in the region. We identify a number of weaknesses in current planning processes and offer recommendations to address these.

Finally, in Chapter 8 we return our focus to the Portland Region and the design of a transmission and subtransmission grid that is capable of providing reliable electric service in a post beneficial electrification period where peak loads are roughly 3-times higher than they are today. At a high level and without subjecting the proposed design to rigorous reliability and stability testing, we estimate that the cost of the expansion and upgrades necessary are in the $2.5 billion range, measured in today's dollars. This amount does not include upgrades to and expansions of the distribution grid.

In addition, we have included six Technical Appendices that provide additional detail and discussion of key modeling assumptions are results for various components of our analysis. We strongly encourage the interested reader to review these carefully. To the best of our knowledge, this is the first time anyone has attempted to merge the concepts of a zero-carbon economy and electric grid design. We welcome all comments on and critiques of our efforts to improve analytical methodologies in this area.

Chapter 2 - The Portland Region

2.1 Geographic Representation

For the purposes of this report, the Portland Region is defined electrically using the boundaries established by CMP in its February 2, 2018 Portland Area Analysis – Solutions Assessment.[6] We refer to this document as the "CMP Study". While this electrical region generally conforms to physical and political features of the greater Portland area, it is not tied to political boundaries or geographic features. The region is defined as the area generally south of Brunswick, north of Saco and west of Gorham that lies electrically downstream of CMP's major 345 KV substations at Surowiec (Pownal) and South Gorham (Gorham). The municipal boundaries are shown on the map in Figure 2-1. The electrical region is shown on Figure 2-4 later in this chapter.

2.2 The Electrical Grid

We provide the electrical representation of the region in a manner consistent with how it is defined and characterized in the CMP study by focusing on transmission and distribution grid infrastructures and current electric loads served. The figures and tables provided below are taken from the CMP study. They are categorized as Critical Energy Infrastructure Information ("CEII") and are therefore confidential and not for public release.

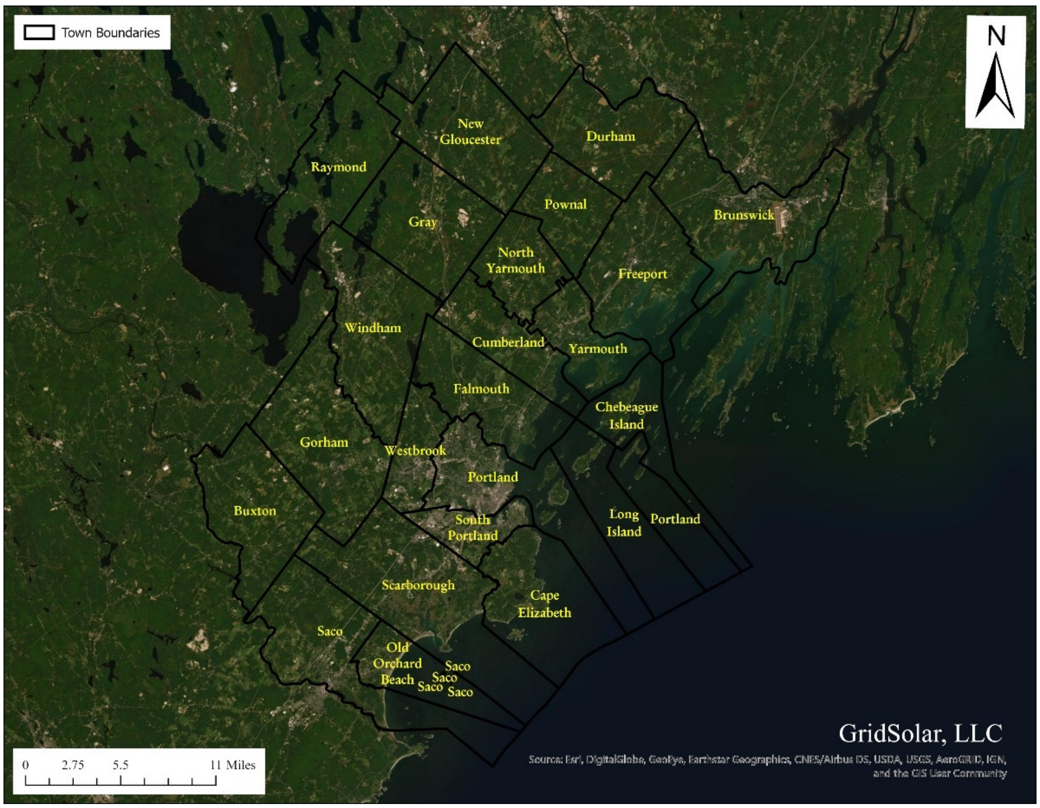
2.2.1 Electricity Generation and Imports

With the exception of a few very small-scale distributed generation facilities, all electricity consumed by end-use customers within the Portland Region derives from five power plants located in the region and from electricity imported into the region. The power plants are the three oil-fired

[6] Maine Power Reliability Program: Portland Area Analysis – Solutions Assessment – Final Report, Central Maine Power Company/RLC Engineering, Maine Public Utilities Commission, Docket No. 2011-00138, February 2, 2018.

units at Wyman in Yarmouth (Wyman 1, 2 and 3)[7], the three natural gas-fired units at Calpine in Westbrook, the four diesel-fired generating units at Cape Station (located in South Portland), the multi-fuel generating plant at the Sappi Westbrook plant and the municipal solid waste generating plant (ECO-Maine) located off outer Congress Street in Portland. The region is interconnected to the New England electric grid through two 345 kV substations located at Surowiec and South Gorham. These substations have 345 kV/115 kV auto transformers that permit electricity to be delivered into the region from the bulk power system in a way that maintains a balance between electricity supplies and demands at all times.

Figure 2-1 Geographic Map of The Portland Region



[7] The largest unit at Wyman, Wyman 4, sends all of its generation along a 345 kV generator lead that interconnects with the larger electric grid at South Gorham. Accordingly, it is electrically equivalent to electricity imported into the region at South Gorham.

2.2.2 High Voltage Electric System

The high voltage or transmission system within the Portland Region consists of all 115 kV and 34.5 kV transmission lines and related substations. We have included electrical one-line representations of each voltage level separately in Figure 2-2 and Figure 2-3, respectively. Most of the region is served off the 115 kV loop formed by the Moshers, Cape, Pleasant Hill and South Gorham substations. The exception is the area north of Portland, including Falmouth, Cumberland, Yarmouth, Freeport and Gray. These areas are tied into the 115 kV loop at the Spring Street and Mosher substations. In addition, this part of the grid is capable of being back-fed from Wyman Units 1, 2 and 3 through the Elm Street substation in Yarmouth. However, since these generating units rarely operate given fuel prices and current electric market conditions, this portion of the region's electric grid is fed for all intents and purposes off the same 115 kV loop as the rest of the region.[8]

The underlying 34.5 kV system presents a more nuanced picture of electric service in the region. Most of the City of Portland and areas south within the region are served off looped 34.5 kV systems that allow for the areas to be served from any point on the loop. Nevertheless, outages of certain 115 kV lines or transformers in this part of the region can create reliability problems for the grid under certain load conditions. The area to the north of Portland is served at 34.5 kV off the Prides Corner substation in a radial fashion, with support at Elm Street in Yarmouth from the Wyman units referenced earlier either when they generate electricity or through the 115 kV system interties at Elm Street substation. A problem with this part of the grid is that outages of components of the 34.5 kV system at either Prides Corner or Elm Street can result in load flows on the 34.5 kV system in this part of the region that exceed the ratings of certain system components.

[8] We understand that Wyman Units 1 and 2 cleared as delisted units in the recent FCM auction conducted by ISO-NE and will be decommissioned in the near future.

Figure 2-2 Electrical Representation of 115 kV System in the Portland Region

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Figure 2-3 Electrical Representation of the 34.5 kV System in the Portland Region

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2.2.3 Distribution System

The distribution system in the region consists of all parts of the electric grid with voltages below 34.5 kV. These include what are often referred to as "feeder circuits" or simply "circuits" and encompass the poles, conduits and wires that deliver electricity at 12.5 kV overhead or underground to end-users. CMP has 96 such feeder circuits in the region.

We have shown these circuits on a map of the region in Figure 2-4. As a general rule, these circuits extend in a radial fashion from one of the 29 CMP 34.5 kV substations across the region, although there are a few feeder circuits that come directly off the 115 kV system.[9]

While electricity flows in multiple directions on the 34.5 kV and 115 kV portions of the transmission system, the manner in which electricity flows on the distribution system is generally in one direction – from the substation out to the customers. Where distributed generation is interconnected to the distribution system and where the output of that generation exceeds the load behind the point of interconnection, excess generation will flow onto the distribution system. If this excess generation does not exceed the total of all loads that are downstream along the same circuit, the distributed generation will not alter the direction of the flows of electricity out from the substation. On the other hand, if this generation exceeds such load, the generation will reverse electricity flows at that point, so that those flows are upstream toward the substation. This could create reliability problems for the grid, depending on whether the grid is designed to accommodate such upstream flows.

Figure 2-4 illustrates the general mismatch between political boundaries, on the one hand, and the design of the electrical grid, on the other. While there are some distribution circuits that lie wholly (or virtually entirely) within a municipality, many of the distribution circuits cross municipal boundaries and serve residents and businesses in adjacent municipalities. This adds a level of complexity to modeling current energy use and the consequences of beneficial electrification within a fully integrated electrical grid that has evolved over the years in response to electrical use rather than the physical shapes of cities and towns. As the use of electricity expands as sectors such as

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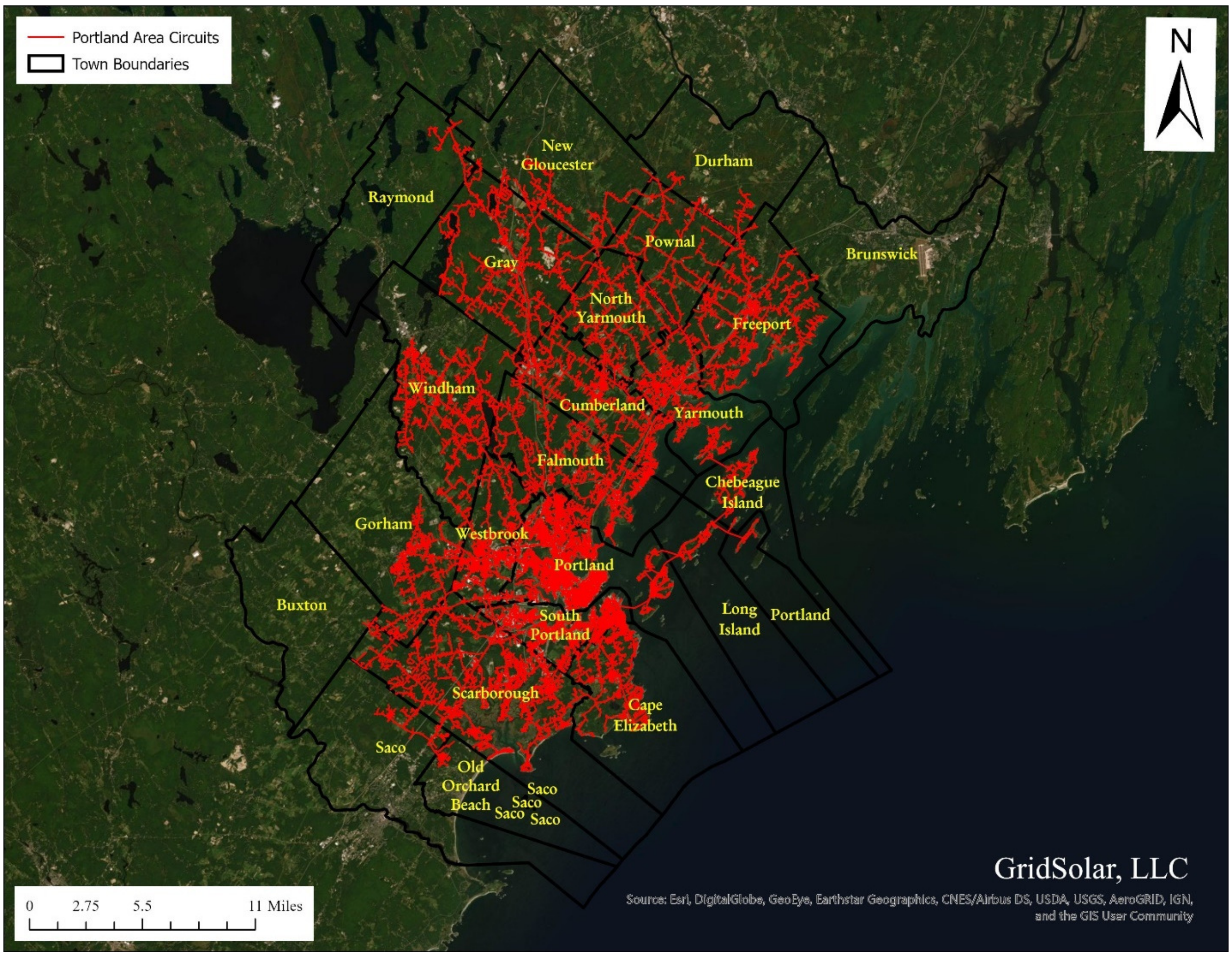
[9] The map does not show any of the secondary distribution components. These are the parts of the distribution system that are downstream of distribution transformers – usually the service drops to individual customers. We have not included this part of the grid in our studies. Our focus is only on CMP's primary system.

transportation and space heating are converted from fossil fuels to electricity, the electric grid will need to expand to accommodate such use. New transmission lines, substations and distribution circuits will be required. While we might expect that some of this new capacity will lie within the same rights-of-way as the existing electric grid, it is quite likely that the requirements imposed by beneficial electrification, some of which we illustrate later in this report, as well as a few decades of economic changes as beneficial electrification occurs will result in an entirely new electric grid structure in the region. For this reason, we use the existing grid and load flows on that grid only to benchmark our modeling efforts and to illustrate the current grid's inadequacies.

Figure 2-4 Electrical Representation of the Distribution Circuits in the Portland Region



Chapter 3 - Current Energy Use

3.1 Introduction

In this chapter, we discuss out estimates of current energy use for each building located in the Portland Area. Because our purpose is to assess current and future energy use in relation to the existing electric grid, our unit of analysis must be geospatial and capable of being mapped to the existing electric grid. Buildings serve this purpose well.

We focused on four types of energy use. The first is current electricity use. This includes all electricity that is delivered by CMP to each building in the region. The other three are non-electric. The first of these is energy used in the transportation sector. This includes gasoline and diesel fuel used by passenger vehicles, buses and trucks. While there is some very small amount of natural gas and propane used for transportation, we ignored this, effectively treating all such use as either gasoline or diesel fuel. The second non-electric form of energy is energy used to provide space heating and "domestic" hot water. The fuels used for this purpose include home heating oil, natural gas and propane. While there is some electric heat in the buildings in the Portland Area, the penetration is very low. We corrected for this in subsequent sections of the report.[10] The last form of energy is energy that is used in commercial and industrial processes. Where such processes are powered by electricity, this energy was included in current electricity use. The remainder of process energy use consists of fossil fuels, primarily natural gas and heating oil.

3.2 Current Electricity Use

There are two general approaches for estimating current electricity use. One approach is to obtain from CMP annual usage information for each service address. This information is available to CMP from the Advanced Metering Infrastructure ("AMI") and smart meters CMP has installed across its entire service territory. This data is confidential and generally not available for use in this type of research work. Even if it were available, however, it may not be the best option. Using

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[10] We did not consider wood fuels (e.g., cord wood and pellets) in this study. The amount of such fuel remains quite small and to the extent that it exists currently, we assumed that the same amount of such use will continue in the future. For example, South Portland reports that only 689 out of 13,205 buildings are heated with wood or coal.

existing usage by service address, in effect, fixes the use of each building and its occupancy to those that exist currently. This may be too constraining, especially for larger commercial and industrial buildings where the use of space is frequently changing as occupancy changes. Production space becomes warehouse space; warehouse space becomes production space; and different types of buildings undergo conversions to support entirely different end-uses.

As an alternative to relying on metered electric use, we modeled current annual electricity use for each building based on three factors – (i) the characterization of that building as either residential, commercial or industrial, (ii) our estimate of that building's square footage and (iii) the annual electricity consumption per square foot for each category of building based on EIA data and other sources. This approach locks in each building's classification as residential, commercial or industrial, but within each category, it uses average energy use characteristics. This approach loses some of the richness associated with specific end-uses that are far from the sector averages – e.g., industrial warehouses, arc-furnace operations, commercial laundries and data centers. This becomes less of a problem as the geographic area of focus increases and the effects of the law-of-large-numbers begins to dominate, driving aggregate energy use within each sector closer to the average for that sector.

3.2.1 Data and Methodology

The first step was to assign each building as a residential, commercial or industrial building. We did this using the building information contained in the tax databases for each municipality where available, and where not available based on zoning and visual inspection. We assumed that any building that shares the same parcel with another building for which there is descriptive information (e.g., heat fuel, heat type, building type) also shares the same attributes. We excluded parking lots, private lots, and the large oil fuel tanks (primarily concentrated along South Portland's waterfront) from this analysis, as the energy use of these buildings is small and not consistent with the energy use of buildings in the commercial and/or industrial categories.

The second step was to calculate the total square footage for each building. This was done by first taking each building's footprint, converting the footprint to square footage and multiplying it by the number of stories in the building. We obtained building footprints from Microsoft's various tools or directly from municipal databases. The number of stories was calculated by taking the raster dataset and subtracting each building's height above sea level (ASL) from the ground elevation ASL to estimate each structure's true height. Then, each building's eave and peak roof height was calculated using ArcGIS's Roof Extraction tool.

Next, we divided each residential building's structural height (from the eave line whenever present) by 3 meters, commercial by 5 meters and industrial by 8 meters, which we assumed as the average building story heights by building classification, to obtain the number of stories per structure (we rounded down any fractions of stories). This number was then multiplied by the building's footprint to derive the total square footage for the entire structure. We only included buildings with a footprint greater than or equal to 500 square feet to eliminate detached garages, sheds and other outbuildings. Manual corrections were made for any structures that did not contain a building type designation by the city. We did this using Google Street View and aerial imagery as a form of verification.[11]

The methodology for calculating the square footage of each building was field-tested by visual inspection of a random sample of residential, commercial and industrial buildings in the region. Using Google Street View and other detailed images of these buildings, we calculated total square footage and compared this calculation to our overall methodology. We found that our methodology overestimated residential building square footage by about 5% and commercial square footage by about 15%. It was pretty much spot-on for industrial building square footage. We then adjusted each building's square footage by these respective percentages.

Table 3-1 presents the results of this methodology. There a total of 73,000 residential buildings, 6,167 commercial buildings and 1,003 industrial buildings in the Portland Area, with a total of just under 300 million square feet.[12]

We relied on different data sources to estimate energy use per square foot for residential, commercial and industrial building types. Table 3-2 shows how our estimate for residential electricity use per square foot was derived. We divided total statewide residential electricity

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[11] We found that we could not rely on the building square footage reported in the municipal datafiles, as the municipal data was inaccurate and/or not properly formatted to assign total square footage to each building's footprint. This was verified through ground truthing that was performed by conducting site visits as well as using aerial imagery, Google Street View, and comparing the city's data to the LiDAR derived results.

[12] We note that the number of residential buildings and the average square footage per building is not the same as the number of households and the average square footage of dwelling units. Our modeling focuses on the building footprint and its height. As a result, we treat multi-story residential apartment buildings, for example, as a single building even though they may include multiple apartment units. This does not impact the total amount of square footage in the building and therefore energy use, as discussed below.

consumption by estimated total residential square footage in Maine. The result is 3.724 kWh/square foot/year ("Residential Electric EUI").[13]

Table 3-1 Summary of Buildings in the Portland Area

	Residential Buildings	Commercial Buildings	Industrial Buildings	Total
Number of Buildings	73,000	6,167	1,003	80,170
Total Square Footage	209,782,673	67,793,059	18,802,851	296,378,583
Average Square Footage per Building	2,874	10,993	18,747	10,871

Table 3-2 Estimated Residential Electricity Use per Sq. Ft.

Total Annual Residential Electricity Consumption (1)	MWh	4,638,535
Type/Number of Residences (2)		
Single Family Homes	No.	517,613
Multi-Family Homes	No.	156,163
Mobile Homes	No.	61,935
		735,711
Type/Average Size of Residences (3)		
Single Family Homes	sq.ft.	2,000
Multi-Family Homes	sq.ft.	950
Mobile Homes	sq.ft.	1,000
Total Residential Square Footage	million sq.ft.	1,246
	kWh/sq.ft.	3.724

Sources

(1) Energy Information Agency - Maine 2017
(2) Maine State Housing Authority - 2008-2012 and 2013-2017
American Community Survey Table B25024; B25032
(3) Residential Energy Consumption Survey (RECS) - 2015, New England
https://www.eia.gov/consumption/residential/data/2015/index.php?view=consumption#by%20fuel

[13] As we note later in this section, we reduced this statewide average by 10% to 3.35 kWh/sq.ft. to better match actual loads we see in the Portland Area.

We estimated electricity usage per square foot for commercial space based on a detailed study performed on behalf of Efficiency Maine Trust in 2015.[14] This study computed end-use electricity consumption for eight categories of commercial buildings. The results ranged from a low of 6.1 kWh/sq.ft. for warehouse buildings to a high of 60 kWh/sq.ft. for food sales and restaurants where there is significant refrigeration required. Office, retail, lodging and clinic facilities were all clustered in the 10 – 13 kWh/sq.ft. range. The study did not compute an average across all facilities. We have used a figure of 11 kWh/sq.ft. ("Commercial Electric EUI") for all commercial buildings in the region. We verified this figure using EIA data. Nationally, total energy use on average across all commercial buildings is about 80,000 btu/sq.ft., about 50,000 btu/sq.ft. of which is electricity. This equals just under 15 kWh/sq.ft. The comparable figure reported by EIA for New England is 12.1 kWh/sq.ft.[15] We would expect New England to be a little less than the national figure, since air conditioning loads are lower, and Maine to be slightly lower still.

It is more difficult to develop a single estimate for industrial electricity use per square foot because of the wide range of process activities that occur within industrial facilities and their relative electricity use intensities. Buildings like the semiconductor plants in South Portland have very high electricity use per square foot, while other industrial facilities such as the boatyards in Portland have relatively low electricity use per square foot. One approach to address the heterogeneity in energy use intensities across industrial classified buildings is to use information about the nature of operations at these buildings or their North American Industry Classification System (NAISC) code where available. This methodology provides some diversity in electricity use intensities across circuits serving industrial buildings. On the other hand, it has the disadvantage of locking in the current use of that industrial space for the foreseeable future. Given the changes that have occurred in Maine's economy and those that are likely to occur over the next few decades, this may not be the best option, even for buildings housing the two major semiconductor operations in South Portland.

An alternative approach, and the one we adopted, is to use average electricity use values for all industrial buildings regardless of how the space is currently being used. This methodology locks in the building footprint but does not lock in current use. Instead, it has the effect of treating all

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[14] "Commercial Building Interval Meter Data Analytics Study – Final Report, submitted to Efficiency Maine Trust by Retroficiency and Cadmus, November 25, 2015, Table B1, page 25.

[15] https://www.eia.gov/consumption/commercial/reports/2012/energyusage/

industrial buildings as essentially homogeneous space and assigns average energy use intensities to all spaces. We use 12 kWh/sq.ft. ("Industrial Electric EUI"). We note that the average industrial electricity EUI across all industries in the U.S. is 76 kWh/sq.ft. The range is from 11 kWh/sq.ft. for furniture making to over 2,000 kWh/sq.ft. for refineries and petro-chemicals.[16] This figure, however, includes all electricity use, including electricity used for process purposes. Since we treat process use separately, see Section 3.4, we need to use a lower figure than the national average.

Multiplying the EUI for a building's category by the square footage of the building results in total annual electricity usage for each building in the region. To model the impact of electricity use on the transmission and distribution grid, this total annual usage must be apportioned to each of the 8,760 hours of the year. We did this by using the CMP residential class hourly load profiles for residential buildings and the CMP medium general service hourly load profiles for both commercial and industrial buildings. This resulted in an electricity usage matrix consisting of 73,000 residential buildings, 6,167 commercial buildings and 1,003 industrial buildings and for each building for 8,760 hours of estimated electricity use.

3.2.2 Results

The results of the calculations described above were tested by comparing these results to actual hourly loads provided by CMP for ten individual circuits in the region. These ten circuits were chosen because they were the only circuits for which CMP provided us with hourly electricity flows. The circuits include approximately 15,000 residential, 850 commercial and 175 industrial facilities with a total actual annual electricity usage of 240,000 MWhs. Figures 3.1 and 3.2 provide a comparison between CMP's actual hourly electricity flows across all ten circuits and our estimates of those flows. Figure 3.1 shows the data by month. Figure 3.2 shows the same comparison by hour of the day over the 12 month year. The graphs confirm the validity of the underlying electric load models. Across the range of circuits, our model predicts total electricity usage of 230,000 MWhs – or 4% below actual usage. (More detail on this validation can be found in Appendix A.)

[16] https://www.eia.gov/consumption/manufacturing/data/2014/#r13.

Figure 3-1 Model Validation – by Month

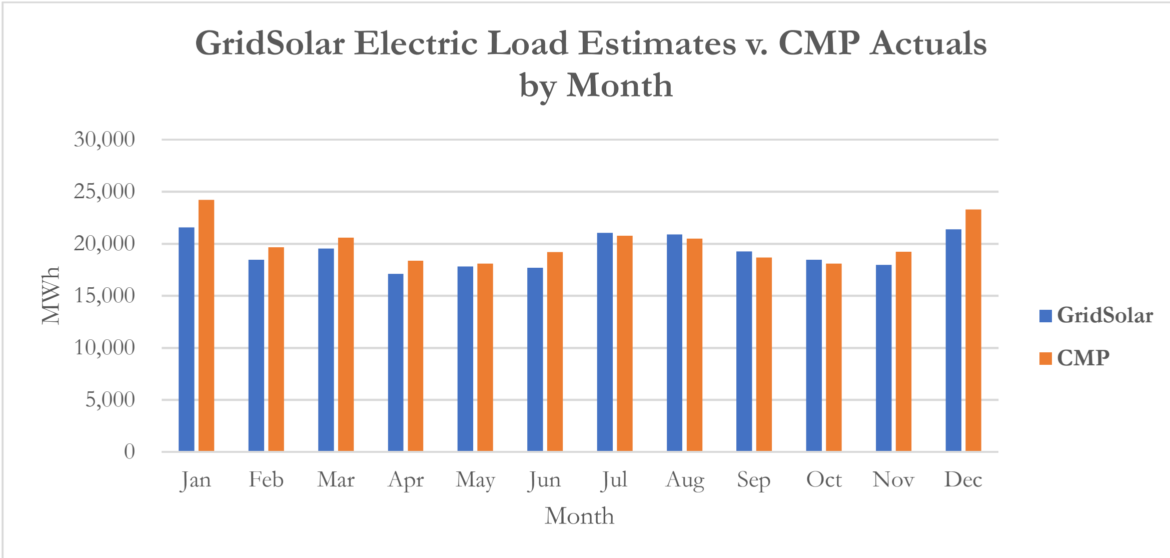
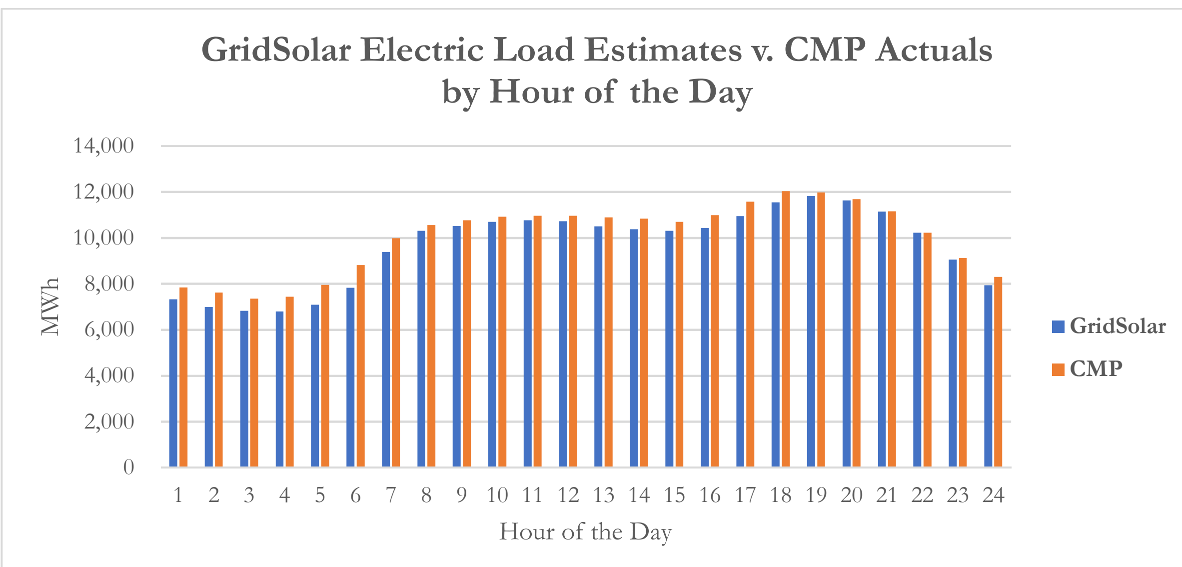


Figure 3-2 Model Validation by Hour of the Day



We estimate that total current electricity usage across the region is about 1.8 million MWh. The breakdowns by residential, commercial and industrial customers for the region is shown later in this chapter in Table 3-3.

3.3 Transportation

Transportation is, by definition, mobile. This fact makes it very difficult to associate the actual use of energy with any specific geospatial location. There are three conventions that can be adopted for assigning fuel use to geographic locations, albeit often for very different purposes. First, there is the place where fossil fuels are purchased. This has the relatively attractive attribute that good spatial data is generally available for the delivery of fuel at wholesale and the sale of such fuel at retail. On the other hand, this method leads to an artificial concentration of use based on the assignment of fuel use to fuel delivery locations.

The second approach is based on miles travelled. States and various industry groups keep relatively good data on the number and types of vehicles using state road networks and the number of miles travelled by these vehicles. This measure is better for larger geographic areas such as a state that encompass most of the physical locations of a vehicle while that vehicle is in motion. It is less applicable for small geographic areas that may encompass only a fraction of total vehicle use.

The third method is where the vehicles are garaged or based. This has the useful feature of assigning energy use to the physical location of the owner or operator of the vehicle rather than the place where fuel is purchased or the state/city in which the vehicle is driven. As we note later in this report, we believe that this convention will be more applicable as we convert to electric vehicles. Electric vehicles are likely to charge at their base locations. This better matches the locations at which vehicles draw fuel off the electric grid with the use of that energy. Accordingly, we use this measure to assign current transportation related energy use geospatially across the region.

3.3.1 Passenger Vehicles

Passenger vehicles are defined by the Secretary of State in Maine to include cars, SUVs, and pickup trucks, where such vehicles are not commercially registered. There are reported to be just under 1 million such vehicles registered in Maine. The Secretary of State's Office provided registrations by municipality. We apportioned the number of passenger vehicles in each municipality by the total residential square footage to determine the geospatial location of each of the vehicles by residential building.

Passenger vehicles in the Portland Area log an average of 10,000 miles per year.[17] Assuming an average fuel efficiency of 25 miles per gallon, total annual gasoline fuel consumption is about 400 gallons or roughly 47 mmbtu per year for each passenger vehicle.

3.3.2 Buses

The Maine Secretary of State reports that there are 4,455 buses registered in Maine, 3,000 of which are classified as school buses. These buses log about 120 million miles a year or approximately 28,000 miles per bus. If we assume that the 70% of the buses that are school buses operate only on weekdays while the remainder operate over the entire seven-day week, the average miles driven per day by bus is roughly 100 miles. If we further assume that buses average 6 miles per gallon, each bus will consume a little under 5,000 gallons of fuel per year, the majority of which will be diesel fuel. This fuel consumption has the energy equivalent of about 700 mmbtu/year.

We obtained from each municipality the number of school buses and city buses, where applicable, that are garaged in each municipality. Portland, for example, reported a total of 44 city buses and 32 school buses. South Portland's totals were reported as 7 and 26, respectively.[18] These buses are garaged at specific locations within the region. We identified those locations and allocated the bus fleets to the buildings at these properties for purposes of assigning charging load to CMP circuits once they have been converted to electricity under beneficial electrification. We describe this process further in the next chapter.

3.3.3 Trucks

The category "trucks" includes vans, single-unit and combination trucks. There are roughly 76,000 registered trucks in Maine, about 7,600 (or 10%) of which are tractor trailer or combination units. Trucks log an estimated 1.2 billion miles in Maine for an average of just under 16,000 miles

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[17] This is different than what would be obtained by dividing the total number of passenger vehicle miles driven (as estimated by the Maine Department of Transportation) by the number of passenger vehicles registered. The numerator in this calculation is higher, because it includes miles driven by non-Maine registered vehicles. Given the tourism activity in Maine, most of which is tied to visitors driving into and around the state, the total energy used by all passenger vehicles regardless of state of registration is higher. Since most of this visitor travel is not located in the Portland Area, we have not included it in our energy modeling.

[18] Portland and South Portland are the only municipalities that reported city buses. There are 356 school buses reported in the Portland Area.

per truck per year. Assuming the average fleet-wide efficiency of these trucks is 12 miles per gallon (this is based on the ratio of car registrations to tractor trailer registrations of roughly 10-to-1), the average truck uses approximately 1,330 gallons of diesel fuel a year. This is the energy equivalent of about 186 mmbtu/year.

The Secretary of State's Office provided registrations by truck class for each municipality. There are a reported 20,061 registered trucks and 1,495 registered tractor-trailers across all municipalities in the Portland Area. Given the wide variety of ownership of these trucks (e.g., the U.S. Post Office, FedEx, commercial establishments, individual contractors), it is difficult to know how many such vehicles are garaged or otherwise based in this region and then to know how to allocate these vehicles spatially across the region for purposes of assigning fuel use to specific buildings.

We use the same approach for allocating the non-tractor-trailers geospatially as we do for passenger vehicles – based on total residential building square footage. This is likely to reasonably approximate energy use for commercial vehicles owned by contractors or other businesses. It is less likely to capture accurately by geographic location the energy use of fleet vehicles.

We allocate the 1,495 tractor trailers in the region to specific areas of the region that currently support tractor terminals of one form or another. To do this, we divided the region into 483 squares of ¼ mile by ¼ mile in size and identified those squares that we believe appropriate for basing truck fleets. Next, we allocated the 1,495 tractor-trailer trucks proportionately to all commercial and industrial building locations within these squares. By assigning the trucks to buildings, we assign them to existing CMP distribution circuits so that charging loads for these vehicles could be sited under beneficial electrification.

3.3.4 Other Transportation

There are three additional transportation sector end-uses of fuel in the region – marine use, airplanes and railroads. Portland and South Portland, in particular, have major port facilities that support both commercial and recreational marine activities that consumes fossil fuels. In addition, the Portland Jetport is a regional air transportation hub that provides commercial and private passenger and air-freight services. Finally, there is commercial and passenger rail service that originates out of the South Portland and Amtrak facilities, respectively. The total amount of diesel, gasoline and jet fuels used across these facilities is not available in any public data. Rather than guess at usage, we have omitted each of these end-use sectors from our study. Combined, these end-use sectors represent a small percent of total energy use and will have no appreciable effect on the results.

3.4 Space Heating/Commercial and Industrial Process Energy

We define energy used for "space heating" as inclusive of all energy used to heat interior space, provide hot water for domestic purposes and for cooking and related activities, but not for commercial or industrial processes. Buildings are generally heated with natural gas or distillate fuels (including heating oil, propane, kerosene and residual oil), although there are some larger industrial buildings that may be heated with coal. The number of buildings that are currently heated with electricity is small. Based on detailed data available for South Portland, less than 2% of residential buildings and less than 7% of commercial buildings are heated with electricity. (See Table 3-3.) For these buildings, electricity used for space heating is already included in current electricity use.

Table 3-3 Heating Fuel by Building Types – South Portland

Heat Type	Residential		Commercial		Industrial		Total
Electric	206	1.7%	60	6.8%	21	11.1%	287
Gas	3,282	27.1	366	41.3%	50	26.3%	3,698
Oil	8,617	71.1%	428	48.3%	107	56.3%	9,152
Wood or Coal	23	0.2%	33	3.7%	12	6.3%	68
Total	12,128	100%	887	100%	190	100%	13,205

Values represent how many buildings use each type of heat as well as the percentage within each building category. There are 617 buildings that do not have a heat type designation.

EIA provides statewide data for monthly natural gas use in Maine by class of customer – residential, commercial, industrial, transportation and electric generation. The class usage is not further broken-down by end-use (e.g., space heating, hot water, processes). This is not a concern for the residential class, where we assume that all-natural gas is used for non-process purposes. However, as we note below, it does present a problem for the commercial and industrial customer classes, where some companies use natural gas for both space heating and process purposes. The discussion that follows describes how we have determined fuel used in each of the buildings for space heat, and how such usage is apportioned by hour over the course of a year. Ordinarily, this apportionment by hour of use is not of much analytical value. However, since fossil fuel used for heating is to be replaced by electricity post beneficial electrification, the hourly consumption pattern of that electricity is critical for the sizing and design of electric grids.

We begin by computing a residential heating energy use intensity which we refer to as the "Residential Heating EUI". We define this as all energy used by residential buildings that is not electricity. We relied on the Maine Governor's Energy Office estimate of 50,000 btu/sq.ft. as the statewide average energy used to heat a Maine residence.[19] If we multiply this EUI by the total square footage of each residential building, we obtain the annual energy used for space heating in that building. For a residential unit of 2,000 sq.ft., the total annual energy used is about 715 gallons of heating oil equivalent.

Next, we developed an hourly profile of residential building space heating use based on the ratio of the heating degree days, ("HDD") that hour to the total HDD for the year.[20] This results in an hourly profile across the 8,760 hours of the year that defines the percentage of annual energy used for residential heating purposes each hour. Multiplying each hour's percentage of total annual energy use by the total annual amount of fuel used by each residential building results in hourly fuel use for that building. Total residential space heating across the Portland Area is then computed by summing across all 73,000 residential building in the region.

The method for estimating energy used for space heating for commercial and industrial buildings is more complicated than for residential use. EIA reports that total energy consumption per square foot for all commercial buildings in New England is 85,500 btu/sq.ft.[21] Of this amount, roughly 47% or 40,000 btu/sq.ft. is electricity. This equates to approximately 12 kWh/sq.ft., as noted in the previous section. The same data shows that roughly 36,000 btu/sq.ft. is used for space heating. We used this figure as the Commercial Heating EUI and allocated this annual total to each hour of the year based on HDD. We defined the remaining 10,000 btu/sq.ft. as Commercial

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[19] https://www.maine.gov/energy/fuel_prices/heating-calculator.php. This is the statewide average and does not include energy used for domestic hot water. We reduced the 50,000 btu/sq.ft. by 10%, since the region has fewer heating degree days ("HDD") than the statewide average. We then increased it by 10% to account for energy used for domestic hot water. This results in an estimated Residential Heating EUI at 50,000 btu/sq.ft. for residential buildings in the Portland Area.

[20] We use the hourly temperatures for Maine as reported by ISO-NE for calendar year 2017.

[21] Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Form EIA-871A of the 2012 Commercial Buildings Energy Consumption Survey.

Process EUI. We used these two EUI measures to estimate the amount of energy used by each commercial building for space heating and process end-uses.

EIA reports energy use for industrial buildings for total electricity used and for the total of all other fuels used. These values can be used to create EUIs for electricity and for all other energy sources. Unlike for commercial buildings, however, the EIA data does not distinguish between space heating and process end-uses for industrial buildings. This distinction can be important. Each end-use has different seasonal and daily patterns, and these patterns will become important as we look to replace fossil fuel use with electricity later in the report.

A further complicating factor is that the range of non-electric EUIs in the industrial sector is much larger than in the commercial sector. Total building EUIs across commercial sectors range from as low as 10,000 btu/sq.ft. for retail malls to as high as 125,000 btu/sq.ft. for inpatient hospital facilities. By comparison, industrial EUIs range from a low of about 40,000 btu/sq.ft. for "furniture and related products" to over 100 million btu/sq.ft. for "petrochemicals" (the national average across all industrial sectors is a little over 1 million btu/sq.ft.).[22] We have used the 36,000 Commercial Heating EUI as an estimate for Industrial Heating EUI, on the assumption that energy used for space heating is not closely related to what goes on inside the space, and allocated this by hour using the same HDD methodology as we used for residential and commercial buildings. On the other hand, we have increased the Commercial Process EUI of 10,000 by a factor of 10 to 100,000 btu/sq.ft. as the Industrial Process EUI. This results in a total, all-energy industrial EUI of about 177,000 btu/sq.ft., which is 13.5% of the national average of 1.3 million btu/sq.ft.

We have no direct way to allocate total annual energy used by commercial or industrial buildings for process purposes by hour of the year. As a proxy, we used the hourly electric load profiles of commercial and industrial buildings to allocate process fuel use on the assumption that both are correlated with overall building activity. We multiply the Commercial Process EUI and Industrial Process EUI by the total square footage of each building to determine annual energy used for process purposes at that building. This is multiplied by the apportionment factor for each hour

[22] Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Form EIA-846, '2014 Manufacturing Energy Consumption Survey.'

for commercial and industrial buildings, as appropriate, to generate hourly fuel usage for process purposes in each of the commercial and industrial buildings.

3.5 Summary of Current Energy Use

We present estimated total energy used in the Portland Area in Table 3-4. This table shows the total energy used across all residential, commercial and industrial buildings in each city by the four end-uses of that energy – electricity, space heating, commercial and industrial processes and transportation. We show energy use represented in MWh for electricity and mmbtu for all other fuels We have divided total energy used for heating and process in each class by fuel - natural gas versus heating oil – based on our knowledge of the natural gas distribution system in each of the municipalities in the region. The relative shares of each fuel are shown in the column labeled "Load Share". This allocation does not impact any subsequent analysis of conversions of these fuels to electricity; the only effect is on current CO_2 emission levels, since natural gas and heating oil have different emission rates per mmbtu. Total energy use in the region is 34 trillion btu. Figure 3-8 presents the relative shares of energy consumed by each end-use and by each customer classification.

All energy use in Table 3-4 is measured at the electric meter or at the burner tip of the heating or process equipment. Using standard EPA figures for emissions per mmbtu for fossil fuels and an average emissions factor of 500 lbs/MWh for electricity,[23] total annual CO_2 emissions are a little over 2.5 million tons per year. [Comparable data for each of the municipalities in the region can be found in Appendix B.]

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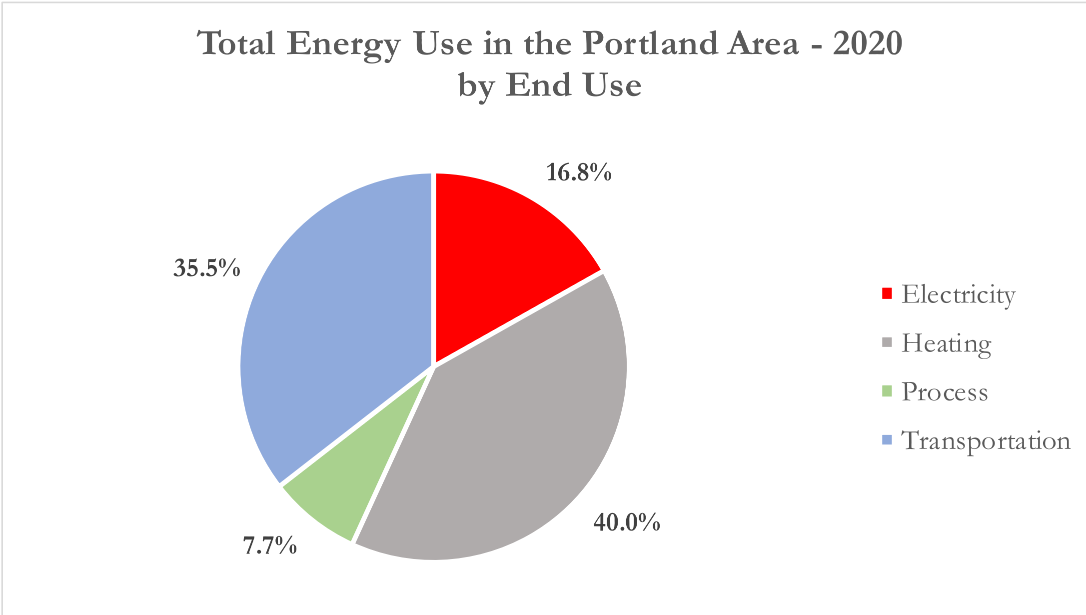
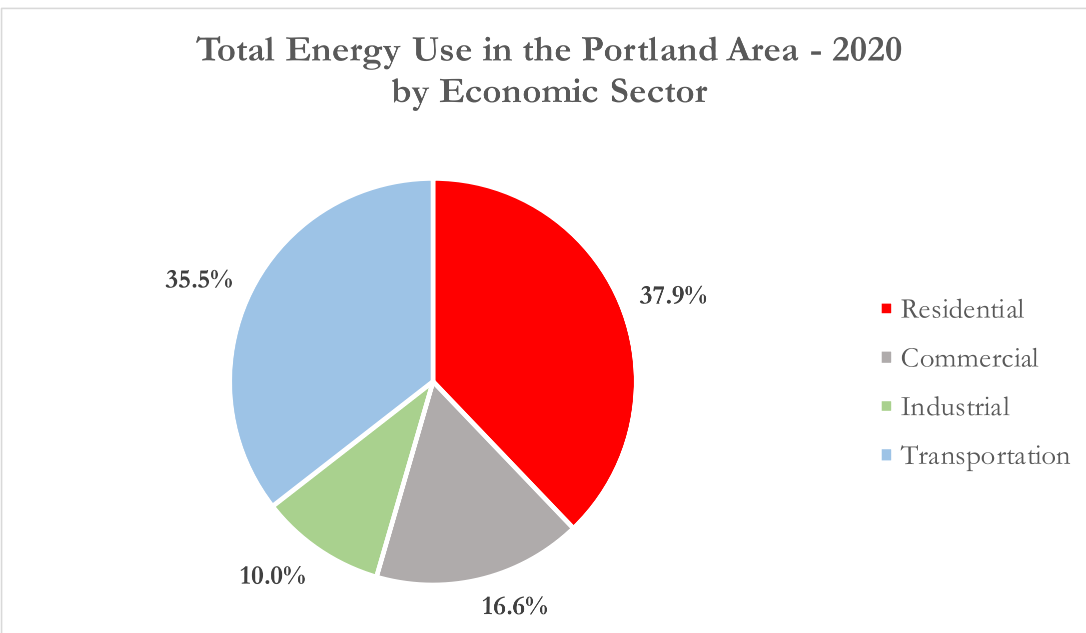
[23] Since the 500 lbs/MWh emissions figure for electricity is measured at the generator, we need to account for transmission losses. We estimate these losses at 8% for Portland and South Portland.

Table 3-4 Total Energy Use for the Portland Region by Class and End-Use

Class / End-Use		Share	2020
Residential			
Electricity	MWh		703,152
Heating	mmbtu		10,489,261
Natural Gas	mmbtu	10%	2,529,060
Heating Oil	mmbtu	90%	7,960,201
Commercial			
Electricity	MWh		745,724
Heating	mmbtu		2,440,550
Natural Gas	mmbtu	20%	1,187,997
Heating Oil	mmbtu	80%	1,252,554
Process	mmbtu		677,931
Natural Gas	mmbtu	20%	336,140
Heating Oil	mmbtu	80%	341,790
Industrial			
Electricity	MWh		231,357
Heating	mmbtu		694,072
Natural Gas	mmbtu	30%	467,576
Heating Oil	mmbtu	70%	226,496
Process	mmbtu		1,927,978
Natural Gas	mmbtu	30%	1,298,821
Heating Oil	mmbtu	70%	629,157
Transportation			
Passenger Vehicles			
Gasoline	mmbtu		8,593,214
Electricity	MWh		0
Commercial Trucks			
Gasoline	mmbtu		2,583,087
Electricity	MWh		0
Buses			
Diesel	mmbtu		201,309
Electricity	MWh		0
Heavy-Duty Trucks			
Diesel	mmbtu		709,710
Electricity	MWh		0
Totals			
Electricity	MWh		1,680,233
Natural Gas	mmbtu		5,819,594
Heating Oil	mmbtu		10,410,198
Gasoline	mmbtu		11,176,300
Diesel	mmbtu		911,019
Total CO_2 Emissions	tons		2,549,202

Figure 3-3 Percent Energy Use by End-Use and Economic Sector





Chapter 4 - Beneficial Electrification

4.1 Overview

In the previous chapter, we estimated total energy use in the Portland Area as 34 trillion btu. The use of this energy creates an estimated 2.5 million tons of CO_2 emissions annually, roughly 36% of which is created by the transportation sector and 48% by space heating and commercial and industrial processes. By comparison, 16% of all emissions originate from the use of electricity. In order to eliminate all CO_2 emissions and achieve a zero-carbon economy across the region, all heating, transportation and process energy end-uses must be converted to electricity through beneficial electrification and that electricity must be generated from zero-emission generation technologies through deep decarbonization.

Our focus in this chapter is on the conversion of all passenger vehicles, buses and trucks in the two cities from gasoline and diesel fuels to electricity; on the conversion of all space heating across all buildings in the region from heating oil, natural gas and propane to electricity; and on the conversion of all distillate fuels and natural gas used for process purposes by commercial and industrial companies in the region to electricity.[24] We are not concerned with how long these conversions will take or how much they will cost residents and businesses. These are both certainly very important issues and ultimately will determine whether the conversions occur. Our focus is more limited to how much more electricity will be consumed and during which hours that consumption will occur as a result of beneficial electrification. In a later chapter, we will explore what this increased use means for electric system planning, the pace at which the electric needs to be built out and the capacity and design of electric grids.

4.2 Transportation

Electrification of the transportation sector has been the most visible and most discussed component of beneficial electrification in the U.S. and around the world. Most of the attention has

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[24] In addition, because conversion of residential heating to electricity involves the replacement of home furnaces with air source heat pumps, we also include incremental electricity use that results from using these heat pumps to provide air conditioning.

focused on passenger vehicles. Increasingly, we are seeing attention spread to buses, as electric buses are being adopted by cities across the country. We are also beginning to see some attention by Tesla and Volvo, among others, pushing the sector forward with designs and prototypes for trucks, including long-haul tractor trailers. The speed with which the conversion of different classes of vehicles occurs will depend on many factors, including the life-cycle costs of ownership, the range of travel offered, the ubiquity of charging stations and the time it takes to recharge vehicles. We focused in this report on the end-state when all passenger vehicles, light trucks, buses and trucks in the region are converted to electricity. In addition, we made certain assumptions described below about the efficiencies of the different classes of motor vehicles, measured not in miles per gallon, but in miles per kWh of electricity used. Finally, we assumed that annual vehicle miles traveled for each class of vehicle remains the same under beneficial electrification as it is today. The only thing that changes is that the vehicles are powered 100% by electricity.

4.2.1 Passenger Vehicles

It is relatively straightforward to convert the total annual amount of gasoline and diesel fuel used to power passenger vehicles to an equivalent annual amount of electric energy required. All we need to do is make some assumptions about how many miles the vehicle travels each year and the vehicle's operating performance. The difficulty is determining when and where the electricity will be drawn off the grid and stored in the battery systems of these passenger vehicles. This is necessary to define the hourly profile of electricity use over the course of the year, and then, based on where the charging occurs, to evaluate the impact of this conversion on the electric grid. To the best of our knowledge, there have been no studies of how Maine electric passenger vehicle owners will charge their vehicles, let alone how the owners of the roughly 250,000 passenger vehicles in the region will act. As a result, we were forced to rely on studies from other states and to modify the results of those studies to reflect Maine driving patterns and weather conditions.

One of the more detailed studies of driver charging behavior is a study done by the California Energy Commission and released in March 2018.[25] A major component of this study involved the survey of travel behavior of households. This survey was used to develop a simulation

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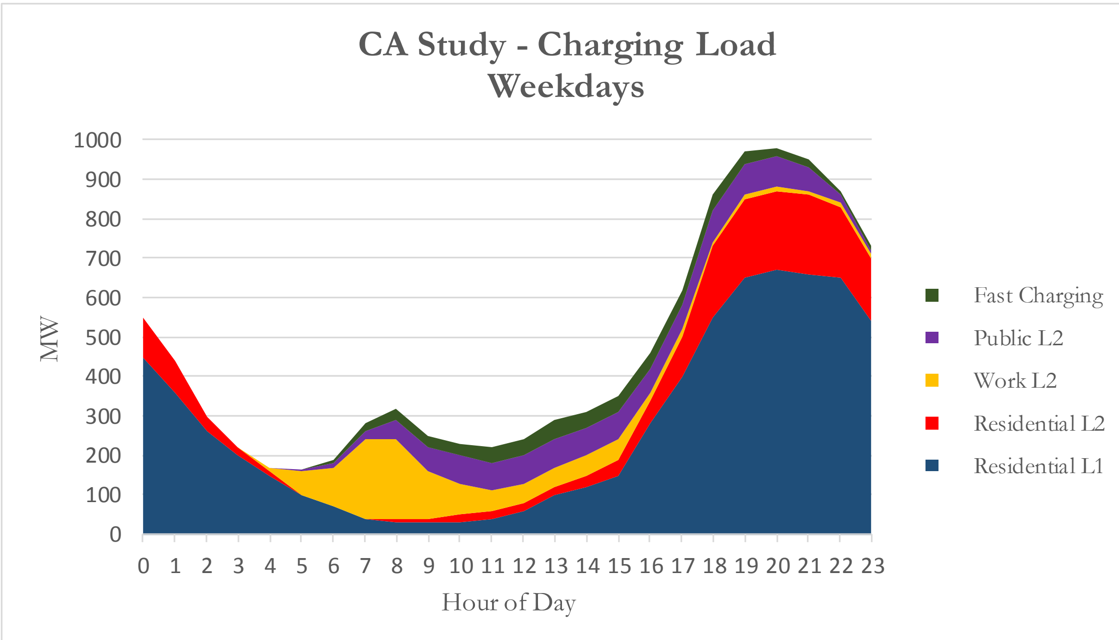
[25] California Plug-In Electric Vehicle Infrastructure Projects: 2017-2025," California Energy Commission Staff Report, March 2018 | CEC-600-2018-001.

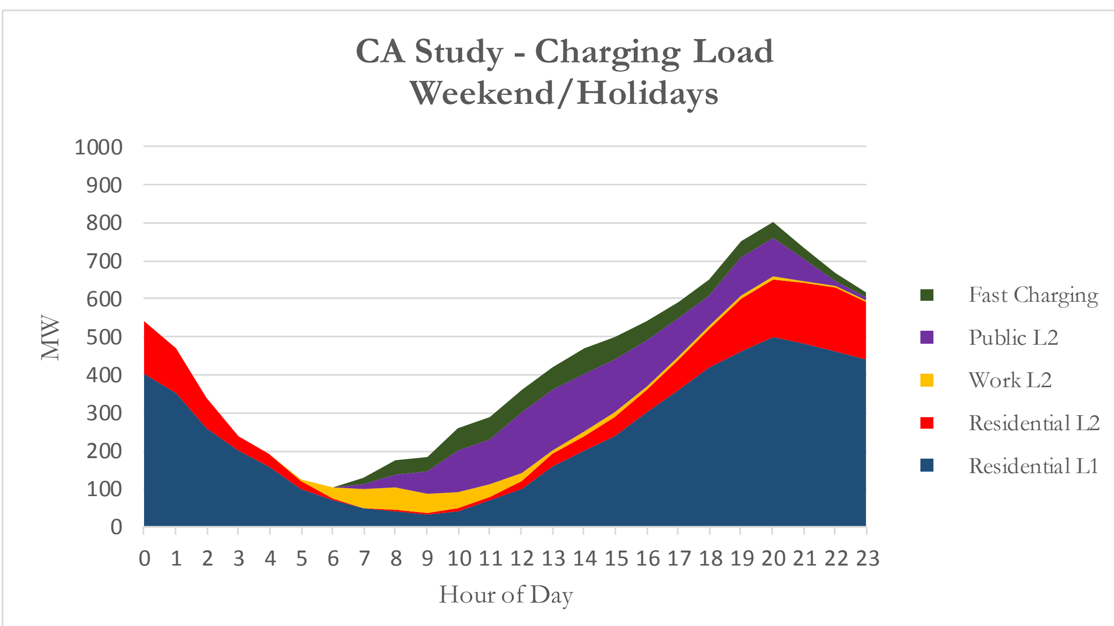
of passenger vehicle travel for 1.3 million passenger vehicles across California. These results were combined with assumptions about the number and location of electric vehicle chargers to create hourly charging profiles for typical weekdays and weekends. We extracted these profiles from that study and present them in Figure 4-1.

The study assumed that electric passenger vehicle charging is done at four types of chargers. The most widely used are Level 1 (L1) and Level 2 (L2) chargers located at each vehicle owner's residence. This charging generally occurs during the evening hours, extending into the overnight hours, as the required charging time increases. Some amount of charging is done during the day at L2 chargers located either at the workplace or at public facilities such as parking garages, shopping malls, and similar types of locations. This charging tends to be concentrated during morning workday hours for charging done at the workplace and during afternoon hours at the other locations. Fast chargers that are located on highways and other heavily traveled routes account for the remaining charging that occurs. This charging occurs during the day and evening hours. The charging pattern for weekdays and weekends is similar, with a few notable differences. The first difference is the electricity load shape for weekday charging is more peaked than for weekends. Second, there is less charging done at the workplace on weekends. Finally, there is more charging done at fast chargers and at public L2 charging locations on weekends.

These two graphs can be used to estimate the hourly electricity consumption required to charge all of the 250,000 passenger vehicles in the region. We have done this by applying the results of the California Study to Maine as a whole, after having made a number of modifications to reflect differences between the two states. First, we scaled the California results down based on the ratio of the number of Maine passenger vehicles (928,132) to the number of passenger vehicles in the study (1.3 million). Second, we scaled the results up slightly to reflect the fact that the number of miles driven per vehicle in Maine is higher than in California. Third, we adjusted the results to reflect differences in monthly travel in Maine, measured in vehicle miles driven per month, and for the fact that miles/kWh of electricity consumption tends to be lower in Maine during cold months when the battery in electric vehicles is called upon to provide heat to the passenger compartment. With respect to this latter adjustment, we assumed that passenger vehicles get 4 miles/kWh during the summer months, 3 miles/kWh during the months of January and February and somewhere in between for the other months. The average miles/kWh over the course of the year is 3.60. This is comparable to what is reported by owners of the Chevy Bolt in New England, but a bit higher than the Tesla models achieve today. We used this higher value to account for improvements in vehicle efficiency over the next couple of decades as more and more electric vehicles are produced.

Figure 4-1 California Study Results – Electric Charging Profiles for Passenger Vehicles





Finally, since state level data indicates that passenger vehicles in the Portland Area put on fewer miles each year than Maine vehicles on average, we adjusted down the Maine level data to reflect this lower annual miles driven level. The adjustments result in total electricity usage of about 495,000 MWh per year region-wide, about 75% of which comes from charging at the residence.

4.2.2 Buses

As noted in the previous chapter, the Maine Secretary of State reports that there are 4,455 buses registered in Maine, 3,000 of which are classified as school buses. These buses drive over 120 million miles a year. This is just under 28,000 miles per bus per year. We assumed that the 70% of buses that are school buses operate only on weekdays, while the remainder of the buses operate over the entire seven-day week. This translates into an average of approximately 100 miles driven per day across the entire bus fleet. Based on the number of city and school buses noted in the prior section and assuming the average efficiency of electric buses is 0.465 miles/kWh,[26] the total annual electricity use of the bus fleet across both cities is calculated to be 7,700 MWhs.

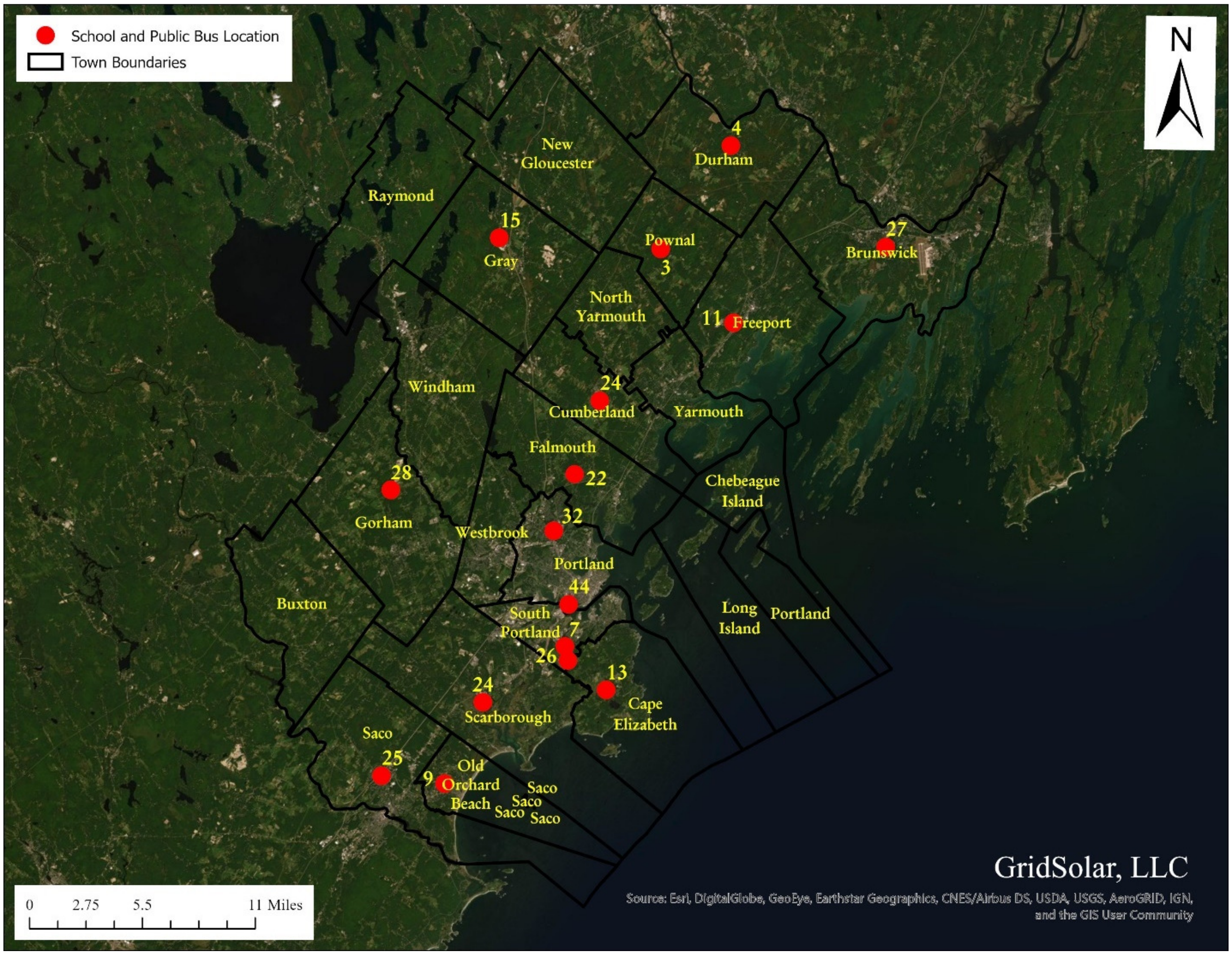
To estimate the charging profile of the buses, we assumed that each bus charges overnight to replenish the electricity used the prior day in driving the 100 miles. We further assumed that the charging occurs during the hours from midnight to 5 am, and that the amount of electricity consumed is evenly distributed over these five hours.[27] Finally, we added a round-trip charging loss of 12.5%.

Figure 4.2 shows the spatial location of the city bus and school bus depots for each municipality as well as the number of buses at each location. The charging loads described above are assigned to each of these physical locations for determining which circuits are providing electric charging services. The total charging load of all the buses in the region is approximately 24,000 MWh per year once they have all been converted to electricity.

[26] See, for example, http://www.nrel.gov/docs/fy17osti/67698.pdf, Table ES-1.

[27] This charging schedule will require chargers with the capacity to deliver 43 kW per hour of charge. A longer charging window is available for school buses. We use this shorter 5-hour window to reduce the amount of overlap between charging buses and residential charging of passenger vehicles.

Figure 4-2 Location of City and School Bus Depots



4.2.3 Trucks

We have assumed that all non-tractor trailer trucks are garaged at residential units across the region and follow the same charging pattern as passenger vehicles. Based on data from the Secretary of State's Office, we adjusted the passenger charging profile upward by 20%, since these vehicles drive on average about 20% more miles per year than passenger vehicles. In addition, we assumed that these vehicles are half as efficient as passenger vehicles, so we adjusted the modified charging profile upward by a factor of 2. This resulted in total annual charging load of 39,000 MWh.

We used a different calculation for tractor-trailers. We assume that the average tractor-trailer uses 0.293 kWh per mile of travel. This is well below the 3.6 miles per kWh for passenger vehicles and also below the 0.465 miles/kWh assumed for buses. Next, we assumed that each tractor-trailer recharges over a 7-hour period from 11 pm through 6 am. As with buses, we assumed that the charging is evenly distributed across these 7 hours and that round-trip inefficiency of the charging/discharging cycle is 12.5%. The total amount of electricity used by tractor-trailers is calculated as 54,000 MWh. The electricity used to charge these commercial vehicles and tractor-trailers is allocated to buildings within the region as described above and in Section 3.3.3.

4.3 Space Heating

Beneficial electrification requires the elimination of all non-renewable fossil fuels used to provide space heating in all buildings and their replacement by electricity. As discussed in the previous section, a small percentage of homes, businesses and institutions in the region are heated with wood and wood pellets. We assumed that these buildings continue to use wood biomass. Since these fuels emit no CO_2 on a life-cycle basis, they do not need to be replaced by electrification. There are also a few buildings that use electric resistance heating. We ignored these. Because their total energy use is small and already included in current electricity consumption, this results in a small double-counting of this energy use. We assume these buildings convert to heat pumps and achieve some reduction in electricity consumed, which reduces somewhat the double-counting. Most of the energy used for space heating across all sectors is distillate fuel (heating oil, propane or kerosene) and natural gas.

To achieve beneficial electrification of this end-use, we have assumed that all residential units are converted to air source heat pumps and that all commercial and industrial facilities switch over to ground source heat pumps to meet their heating requirements. This assumption is for convenience; altering the relative percentages of each technology in each sector would not change total electric usage appreciably. It might, however, effect peak loads, since air-source units are less efficient than ground-source units when ambient air temperatures are low and heating demand is greatest.

We assume that air source heat pumps have a coefficient of performance (COP) that is a function of ambient air temperatures according to the following equation:

$$COP = (0.025 * T) + 1.75 \qquad (1)$$

(where T is ambient air temperature each hour measured in Degrees F) [28]

This means that at an outside air temperature of 50ºF the COP is 3.0, and the heat pump uses one-third the amount of electricity as resistance heating would use to provide the same amount of heat. Based on a general review of the literature, we assumed that ground source heat pumps have a constant COP of 3.5 when providing heat, based on the fact that the temperature of the earth does not vary by season.[29]

As homes and businesses electrify by converting to air and ground source heat pumps, these heat pumps are replacing furnaces, boilers and other equipment that burn distillate fuels or natural gas to generate heat. We assumed that existing residential, commercial and industrial heating systems operate at an average efficiency of 82.5%. The commercial and industrial levels are consistent with manufacturing specs for new equipment and for older equipment that is well maintained. The figure for residential heating systems reflects actual operating performance across all such systems.[30] Since the air source and ground source heat pumps deliver heat directly, the amount of electric energy required to provide the equivalent levels of heat provided by burning distillate and natural gas is equal to the quantity of those fuels used multiplied by the average efficiency value noted above. We performed this calculation on the hourly heating fuel use values calculated as described in Section 3.4 to obtain hourly electricity equivalents. The results are shown in Figure 4-3 for all residential, commercial and industrial buildings across the region.

Not surprisingly, electric load requirements for heating purposes are highly seasonal, with the highest loads occurring during the winter months and on the coldest hours during these months. The total electric load for heating end-use purposes is 1,140 GWh, which is 68% of current electricity usage in the region. Peak heating load is 737 MW, which occurs during the winter

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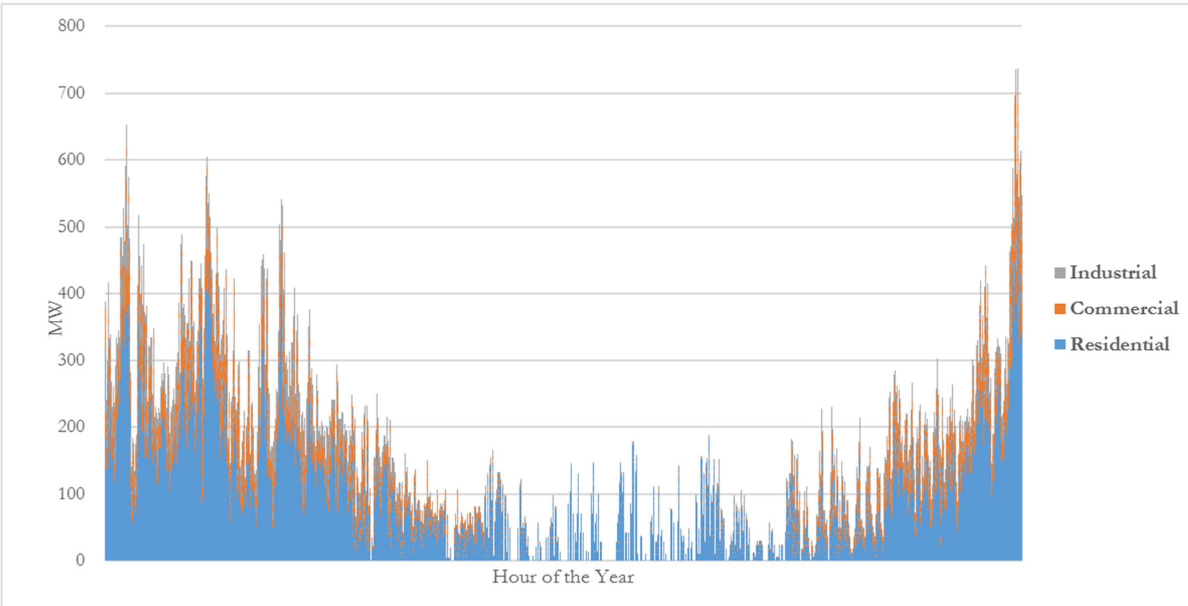
[28] Source: "Natural Gas and Electric Positioning and Gas Technology Update," William E. Liss, gti, Gas Technology, May 2017, p. 33.

[29] Because the number of heating degree days in Maine is much larger than cooling degree days, ground-source heat pumps extract more heat from the ground during the winter than they discharge into the ground during the summer. Depending on the conductivity of the soils, this imbalance must be mitigated by the injection of additional heat into the ground-source heat pump wells over the course of the year.

[30] "Maine Single-Family Residential Baseline Study, NMR Group, Inc., submitted to Efficiency Maine Trust, September 14, 2015.

months.[31] This is 276% of the current peak load of about 271 MW. This results in a low annual load factor for this end-use of about 18%.

Figure 4-3 Estimated Hourly Electric Heating Loads by End-Use Sector



4.4 Residential Air Conditioning

One of the important advantages that heat pumps offer residential consumers is the ability to operate them in reverse mode to provide cooling for interior spaces during summer months. Today, while most commercial and industrial facilities have air conditioning in areas that impact worker productivity, only about 25% of Maine's roughly 700,000 residences have some form of central air conditioning systems or window units.[32] As all residences convert to air source heat

[31] Peak heating loads occurred during the early morning hours on December 30th when temperatures in the Portland Region reached -13^{0} F. The coldest recorded temperature for Portland was -21^{0} F on February 11, 1983. Accordingly, this peak load is reasonably representative of peak loads going forward, though a bit above what could be referred to as "design conditions".

[32] A survey of households performed on behalf of Efficiency Maine Trust in 2015 found that 13 out of the 41 homes visited in the survey had some form of cooling equipment, most of which was room air conditioners. We have reduced the percentage to 25% as an estimate of the households with full-house air conditioning and applied this statewide

pumps for space heat, they will gain central air conditioning as a side benefit. This represents a net increase in total electricity use by households during the summer months.

For the 25% of residential buildings that have air conditioning, the increased electricity usage due to air source heat pumps during the summer will offset the electricity use of their existing air conditioning systems and thus results in no incremental electricity usage.[33] For the remaining 75% of residential buildings, electric use will increase. We assumed that the average air conditioning requirement is for 1,500 sq.ft., requiring 2 tons of chiller capacity. The amount of electricity required to power these units is directly related to ambient air temperatures. Finally, we assumed that no air conditioning is used when ambient air temperatures are below 70ºF. This relationship can be approximated using the following linear equation for ambient air temperatures between 70ºF and 100ºF:

$$\text{Multiplier} = .005 * T - 0.15 \qquad (2)$$

(where T is ambient air temperature each hour measured in Degrees F and the Multiplier is multiplied by 4 kW/hour to obtain predicted energy use based on ambient air temperature each hour) [34]

The increase in residential electricity use for each unit is calculated as the ratio of that unit's sq.ft. to 1,500 multiplied by 4 kW/hour multiplied by the Multiplier in Equation (2). Since we do not know which residential units have air conditioning and which do not, we assigned an air conditioning load to every residential unit but reduced that load by 25%. While this will misrepresent the air conditioning-related electricity use for any one unit, it provides a reasonable estimate of air conditioning-related electricity use across the hundreds to thousands of units on each circuit. Total annual electricity usage for this end-use is shown in Figure 4-4.

Total incremental energy use for residential air conditioning is only 110,000 MWh, virtually all of which occurs during the summer months. Peak demand is 132 MW, which means the annual

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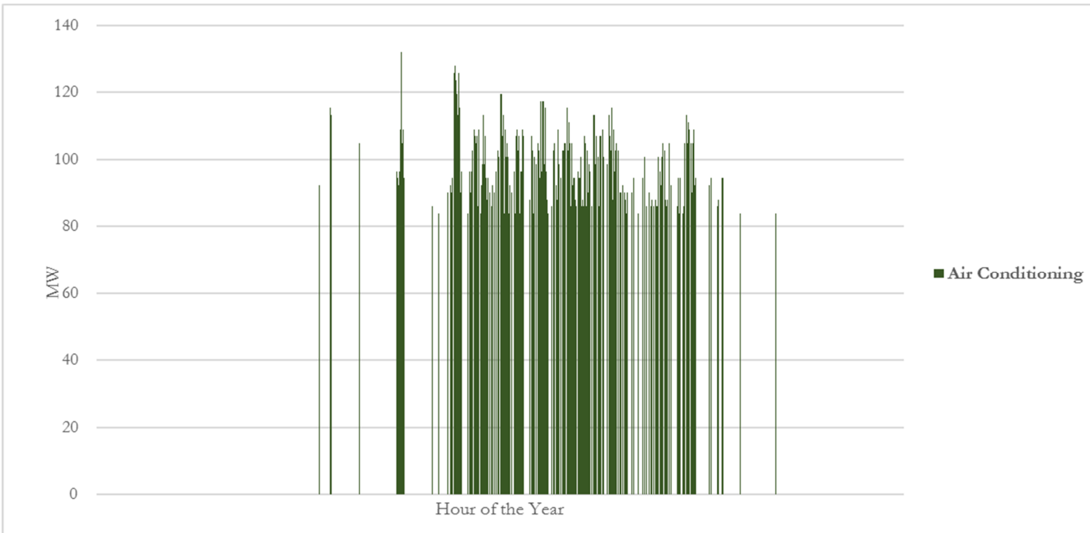
average percentage to Portland and South Portland residential buildings. "Maine Single-Family Residential Baseline Study, NMR Group, Inc., submitted to Efficiency Maine Trust, September 14, 2015, at page 62.

[33] Since heat pumps are more efficient than window AC units, these 25% of households may see a reduction in total energy use. We do not factor this into the analysis as it would be very small in any case.

[34] See for example, https://asm-air.com/airconditioning/much-cost-run-air-conditioner/

load factor is 9.5%. This usage, however, is seasonally countercyclical to space heating. Even though the total usage is small and has itself a poor load factor, use of heat pumps to provide air conditioning actually improves the overall load factor of the electric grid as the grid expands to serve beneficial electrification.

Figure 4-4 Residential Air Conditioning – Hourly Loads



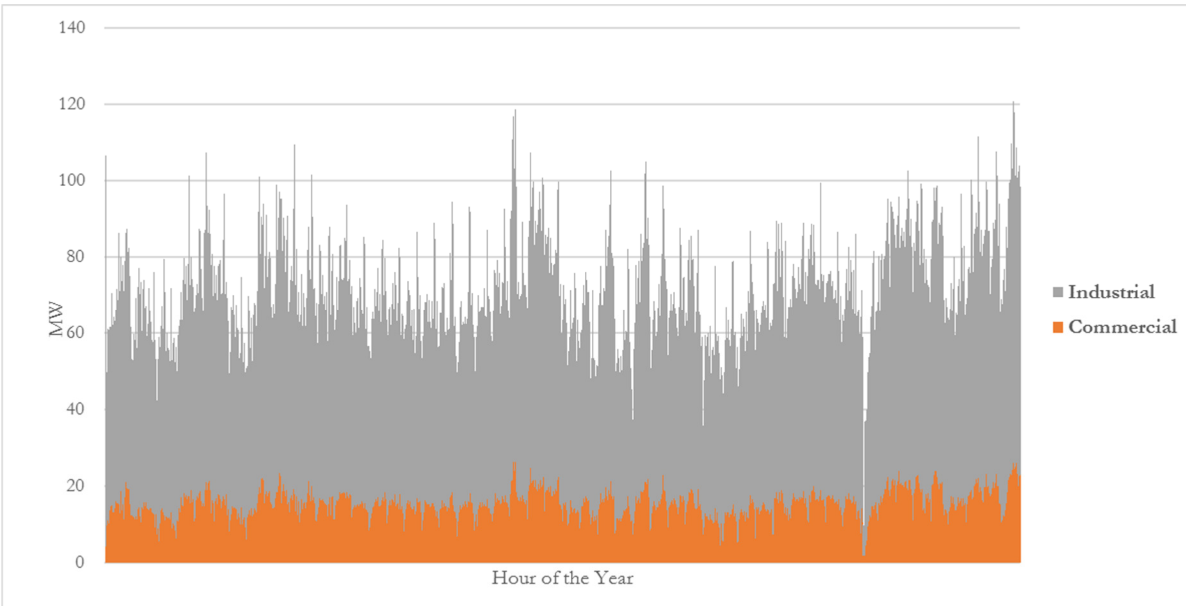
4.5 Commercial and Industrial Processes

Beneficial electrification also requires the conversion of all process end-uses in the commercial and industrial sectors from distillate fuels and natural gas to electricity.[35] We assumed that the btus of usable heat from current boiler operations is displaced on a 1-to-0.825 basis for both commercial and industrial customers by btus of electricity to account for inefficiencies of existing heating systems. We applied these values to the hourly process requirements to obtain hour electric load equivalencies. These are shown in Figure 4-5. The total annual electricity requirement for process loads is 583 GWh. This is about 35% of current electricity usage in the region. The annual

[35] We assume that processes that are currently fueled by biomass remain fueled by biomass, as these already meet the zero-carbon emissions target. The amount of biomass used for this purpose in the region is very small.

peak load for this end-use is 123 MW. As a result, the annual load factor of this usage profile is 54%.

Figure 4-5 Estimated Hourly Electric Process Loads by End-Use Sector



4.6 Summary

Table 4-1 provides a summary of the amount of electricity that is required to achieve full beneficial electrification across the Portland Area. This amount of electricity provides for the continued powering of all homes and businesses at their current levels, plus (a) conversion of all space heating and domestic hot water use in all residential, commercial and industrial facilities to electricity, (b) extension air conditioning to all residential units, (c) conversion all fuels used in commercial and industrial processes to electricity and (d) electrification our transportation sector (passenger vehicles, buses and trucks).

The first row of Table 4-1 shows current electricity use. The region currently consumes an estimated 1,680 GWh of electricity across all sectors and all end-uses. Annual coincident peak demand is an estimated 271 MW. This provides a good benchmark for the generation capacity required plus the size of the transmission and distribution system necessary to serve current loads across all sectors of the economy in the region. To achieve beneficial electrification requires a grid that is capable of transmitting and distributing a 2.5-fold increase in total electricity usage, plus, more importantly, a 4-fold increase in coincident peak load. As a result, estimated total grid utilization falls from a very high 71% today to a much lower 43% with full beneficial electrification.

Table 4-1 Summary – Electricity Use by End-Use Sector Under Beneficial Electrification

Load Type	**Total Loads (MWh)**	**Maximum Demand (MW)**	**Capacity Factor %**
Current Electricity Use	1,680,233	271	71%
Total Heating	1,140,843	738	18%
Residential AC	110,542	132	10%
Total Process	583,248	123	54%
Total EV Charging	613,343	145	48%
Total Loads	4,128,208	1,086	43%

Note: Demand levels shown are for each Load Type, respectively. Demand levels for Total Loads are the coincident demands across all load types.

While the total amount of end-use energy provided at its point of use post beneficial electrification is the same as current energy use in Maine, the conversion of heating, transportation and process to electricity reduces the primary energy required. As shown in Table 3-4, the region currently uses 34 trillion btus of energy, net of biomass and marine and jet fuels we have not included. Of this total about 5.7 trillion btus or 17% is electricity. In contrast, once full beneficial electrification is achieved, the only energy consumed will be electricity. The amount will be 4,110 GWh as shown in Table 4-1. This is about 14.1 trillion btus and represents a nearly 59% reduction in total energy used, measured in btus consumed.

Figure 4-6 presents the estimated hourly loads by end-use over the course of a year, assuming beneficial electrification as described above. This graph provides a useful illustration of just how electricity use changes as Maine moves to beneficial electrification. The first thing to note from Figure 4-6 is the impact of converting heating to electricity. This not only increases total electricity use, but more importantly it shifts peak electricity demand to the winter. The second thing is the very small impact that residential air conditioning has on the overall load shape. The concentration of that load during the summer months means that it can be met with no incremental investments in the transmission and distribution grid, beyond those necessary to meet heating loads.

Table 4-2 looks at energy use in the region at 10-year intervals from 2020 to 2050, assuming full beneficial electrification occurs by 2050 consistent with state policy objectives. This table uses beneficial electrification conversion rates for heating, processes, air conditioning and transportation reported in a parallel modeling effort we have undertaken. As electrification occurs, the amount of each fossil fuel decreases in each end use and is replaced by electricity. The most important effect of this conversion to electricity is to reduce CO_2 emissions, as shown in the last row of Table 4-2.

Figure 4-6 Hourly Electricity Use by End-Use Sector Under Beneficial Electrification

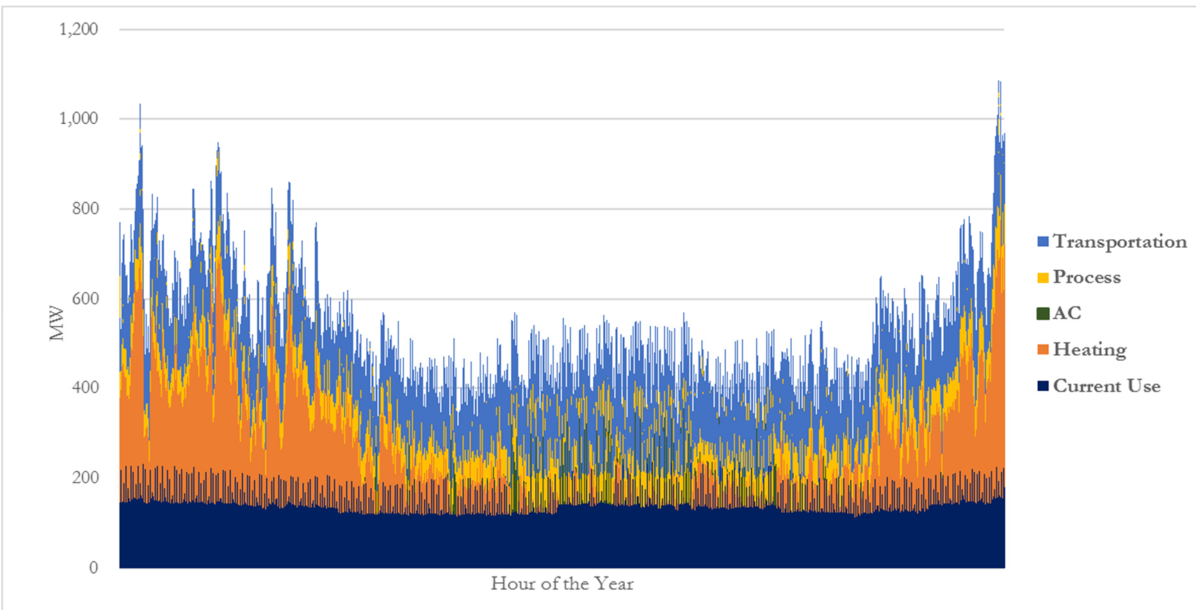


Table 4-2 Energy Use by Fuel – 2020 - 2050

Energy Use Table			Portland Area			
Class / End-Use						
Residential		**Share**	**2020**	**2030**	**2040**	**2050**
Electricity	MWh		703,152	716,591	1,057,697	1,754,085
Heating	mmbtu		10,489,261	10,373,879	7,027,805	0
Natural Gas	mmbtu	10%	2,529,060	2,501,241	1,694,470	0
Heating Oil	mmbtu	90%	7,960,201	7,872,638	5,333,334	0
Commercial						
Electricity	MWh		745,724	747,441	798,745	1,053,523
Heating	mmbtu		2,440,550	2,413,704	1,635,169	0
Natural Gas	mmbtu	20%	1,187,997	1,174,929	795,958	0
Heating Oil	mmbtu	80%	1,252,554	1,238,775	839,211	0
Process	mmbtu		677,931	677,931	671,151	0
Natural Gas	mmbtu	20%	336,140	336,140	332,779	0
Heating Oil	mmbtu	80%	341,790	341,790	338,372	0
Industrial						
Electricity	MWh		231,357	231,845	250,318	707,258
Heating	mmbtu		694,072	686,437	465,028	0
Natural Gas	mmbtu	30%	467,576	462,432	313,276	0
Heating Oil	mmbtu	70%	226,496	224,005	151,753	0
Process	mmbtu		1,927,978	1,927,978	1,908,698	0
Natural Gas	mmbtu	30%	1,298,821	1,298,821	1,285,833	0
Heating Oil	mmbtu	70%	629,157	629,157	622,865	0
Transportation						
Passenger Vehicles						
Gasoline	mmbtu		8,593,214	8,163,553	3,695,082	0
Electricity	MWh		0	24,795	282,667	495,906
Commercial Trucks						
Gasoline	mmbtu		2,583,087	2,472,014	1,239,882	0
Electricity	MWh		0	1,684	20,369	39,171
Buses						
Diesel	mmbtu		201,309	192,451	100,654	0
Electricity	MWh		0	1,055	11,984	23,968
Heavy-Duty Trucks						
Diesel	mmbtu		709,710	679,193	340,661	0
Electricity	MWh		0	2,335	28,235	54,298
Totals						
Electricity	MWh		1,680,233	1,725,746	2,450,015	4,128,208
Natural Gas	mmbtu		5,819,594	5,773,563	4,422,315	0
Heating Oil	mmbtu		10,410,198	10,306,366	7,285,535	0
Gasoline	mmbtu		11,176,300	10,635,567	4,934,964	0
Diesel	mmbtu		911,019	871,644	441,315	0
Total Energy Use	mmbtu		34,051,744	33,477,111	25,446,030	14,089,575
Total CO_2 Emissions	tons		2,549,202	2,379,708	1,547,438	0

Chapter 5 - Distributed Solar Photovoltaic Generation

5.1 Introduction

The prior chapters have focused on the use of electricity. In this chapter, we turn our attention to the generation of electricity using renewable, zero-emission technologies, consistent with achieving deep decarbonization. There are many technologies that fit this bill, e.g., wind, solar, tidal, hydroelectric, geothermal, ocean current or wave, to name a few. For our purposes, we look only at technologies that we believe can be physically sited within the Portland Area, that can meet environmental regulations, that are politically acceptable and that are financially viable. This leaves only one technology – distributed solar PV; and given the high density of development within the two major cities in the region, we restrict this technology to rooftops only.[36]

The model we have developed to estimate potential solar generation has four components. The first component is the solar irradiance model. This component calculates the amount of solar energy that strikes each square meter of rooftop each hour of the year across all buildings in the region. The second component is building specific. It provides a characterization of each building's rooftop surface based on the contiguous size of each rooftop plane and the slope and aspect of that plane. The last component applies certain key parameters to weed out rooftops or portions of rooftops that are not suitable for solar PV systems based on physical characteristics and economic value.[37] Appendix C provides a detailed discussion of each component. The application of the model results in an estimate of the total amount of distributed solar generation that can be developed in the Portland Area and the geospatial location of each such solar generator. The next chapter combines the geospatial generation profile with the geospatial distribution of electric loads from the prior chapter to calculate circuit and grid-wide balances to assess the adequacy of the

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[36] There are likely to be locations within the region that can support canopy solar PV systems above parking lots or ground-mounted systems. We have not attempted to incorporate these in the modeling as doing so would alter the geospatial use of land in the region, something that is beyond the scope of this analysis.

[37] A fourth component would factor in shading; that is, whether any plane or portion of any plane on each rooftop is subject to shading by neighboring trees, buildings or other structures. The data requirements for including a shading component are very significant at this time; we did not include this component.

current electric grid to accommodate beneficial electrification and the widespread buildout of distributed solar generation.

5.2 Rooftop Solar PV – Modeling Results

The results of the solar PV modeling are shown in Table 5-1. We show results for each of the interim 10-year periods from 2020 through 2050, assuming solar PV penetration rates of 0%, 1%, 33% and 100%, in 2020, 2030, 2040 and 2050, respectively, in each of the three sectors. Table 5-1 shows results broken out by building classification – residential, commercial and industrial. We show the sum of the square footage of the building footprints of each building in each building category, the total number of solar PV panels installed, the maximum hourly generation of the installed solar panels, the percentage of total rooftop covered by these solar panels and the total annual solar PV generation, measured in MWh. The bottom rows compute the totals across the three building categories.

Focusing on 2050, maximum buildout of rooftop solar PV systems on all buildings in the Portland Area results in the installation of 2.8 million panels. Based on the representative solar PV panel used in the modeling, as discussed in Technical Appendix C, the total installed capacity is 1,011 MW. The graph in Table 5-1 shows the generation duration curve for these panels. It shows an annual capacity factor across all 2.8 million panels of 18%. In addition, while the total installed capacity is 1,011 MW, the maximum hourly generation was just less than 900 MW. This differential reflects the variability in aspect and orientation across all panels on all buildings.

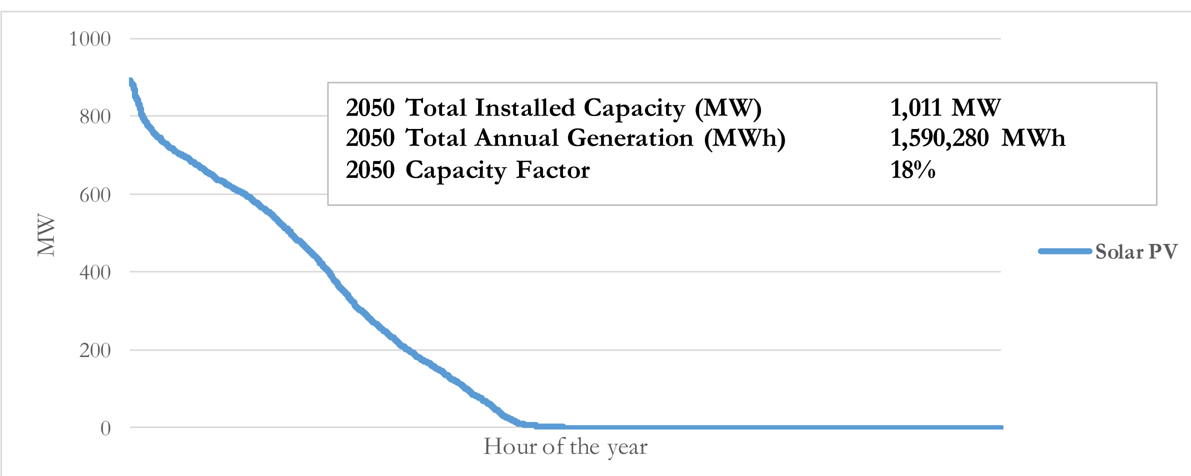
The solar panels are estimated to cover about 25% of the roof surface of all residential buildings. Assuming a uniformly distributed compass orientation of residential buildings, we would expect 50% of all rooftop surfaces to be north of either due east (90^0) or due west (270^0) and therefore not suitable for solar panels, based on the criteria we used in the modeling, as discussed in Technical Appendix C. The 25% coverage ratio suggests that of the remaining 50% of all rooftop planes, fully half do not qualify for installation because they are too small or too steep.

The coverage ratios for commercial and industrial buildings are slightly higher at 28.6%. Most of the commercial and industrial rooftops are flat and because of this are qualified based on compass orientation for solar PV installations. However, to increase the amount of electricity generated by these panels, we have imposed a 30% inclination requirement. This inclination requires interrow-spacing to avoid shadow effects, resulting in an effective usable surface area of roughly 33% of total rooftop surface. The remaining unusable surface area relates to non-flat roof building planes and other factors impacting rooftop suitability.

The generation duration curve at the bottom of Table 5-1 illustrates the difficulty of using solar PV to serve electric load. During the relatively few hours of very high solar generation (those hours to the left when generation is above 600 MW, for example), solar generation will exceed load, requiring the capacity to export excess generation over the grid to regions outside the Portland Area. In contrast, during the more than 50% of the hours when there is no solar generation, all load in the Portland Area must be served by imported electricity. Since this includes those hours of maximum loads on cold winter evenings, the presence of solar generation, even at maximum build-out levels, has virtually no impact on the required capacity of the transmission and distribution grid.

Table 5-1 Installed Solar PV Generation – Portland Area

		2020	2030	2040	2050
Residential					
Pct. Of Bldgs with Solar PV	%	0%	1%	33%	100%
Total Bldg. Footprint	Sq.Ft.	127,783,933	127,783,933	127,783,933	127,783,933
Number of Solar Panels	No.	0	19,415	582,463	1,765,038
Maximum Hourly Generation	MW	0.00	6.12	183.61	556.41
Pct. Of Rooftop Covered	%	0.00%	0.28%	8.47%	25.68%
Annual Solar Generation	MWh	0	10,691	320,736	971,929
Commercial					
Pct. Of Bldgs with Solar PV	%	0%	1%	33%	100%
Total Bldg. Footprint	Sq.Ft.	50,412,359	50,412,359	50,412,359	50,412,359
Number of Solar Panels	No.	0	8,547	256,403	776,978
Maximum Hourly Generation	MW	0.00	2.75	82.62	250.35
Pct. Of Rooftop Covered	%	0.00%	0.32%	9.46%	28.65%
Annual Solar Generation	MWh	0	5,027	150,812	457,005
Industrial					
Pct. Of Bldgs with Solar PV	%	0%	1%	33%	100%
Total Bldg. Footprint	Sq.Ft.	17,342,593	17,342,593	17,342,593	17,342,593
Number of Solar Panels	No.	0	2,932	87,961	266,548
Maximum Hourly Generation	MW	0.00	0.96	28.79	87.24
Pct. Of Rooftop Covered	%	0.00%	0.31%	9.43%	28.57%
Annual Solar Generation	MWh	0	1,775	53,244	161,347
TOTAL - All Buildings					
Total Bldg. Footprint	Sq.Ft.	195,538,885	195,538,885	195,538,885	195,538,885
Number of Solar Panels	No.	0	30,894	926,826	2,808,565
Maximum Hourly Generation	MW	0.00	9.83	295.02	894.00
Pct. Of Rooftop Covered	%	0.00%	0.29%	8.81%	26.70%
Annual Solar Generation	MWh	0	17,493	524,792	1,590,280



Chapter 6 - Energy Balances

6.1 Introduction

In Chapter Four, we focused on how electricity use will expand and change under beneficial electrification of the transportation, space heating and commercial and industrial processes. In Chapter Five, we turned our attention to estimating the total amount of electricity that could be generated within the region using rooftop distributed solar PV systems. In this chapter, we combine the results from these two chapters and in the process introduce a concept we refer to as an "energy balance". We show that, because total energy use (as measured by btus consumed) falls as society replaces distillate and fossil fuels used in transportation and space heating with electricity, the overall energy balance in the region improves as a result of beneficial electrification. The region still imports virtually 100% of the energy consumed – there is just less energy consumed. When we introduce the full development of distributed rooftop solar PV systems across the region, the energy balance improves further. However, even with maximum solar PV generation, this generation represents only 1,590 GWh of the 4,128 GWh (38.5%) of all the energy consumed across the region and all sectors post beneficial electrification.

While the overall regional energy balance is important, energy balances within subregions or related to specific components of the electric grid are often more important. Conditions of imbalance impose stress on the grid and can result in failures that can lead to widespread electric outages. We examine three components of the grid – individual electric circuits, electric transformers and substations. We show that beneficial electrification will impose electric loads on the grid that exceed the carrying capacities of the current system, often by significant factors. Further, the development of distributed solar generation will create situations of reverse power flows on the majority of the distribution circuits in the region. This will necessitate the redesign and reconfiguration of virtually the entire distribution grid within the region.

The redesign of the distribution grid is only one result of beneficial electrification and increased distributed solar generation. The second result is what this means for the transmission grid. While the energy balance in the region is improved through beneficial electrification, the reduction is accomplished by substituting increased electricity flows into the region for distillate and natural gas deliveries through tankers, trucks and pipelines. The increases in electricity imports are well beyond the physical capabilities of the existing transmission and subtransmission grids in the region. We conclude this section by focusing on what the peak electricity balances in the region means for the expansion of the transmission grid.

6.2 Energy Balances

We define energy balance as the ratio of the total amount of all energy that is generated at a specific location to the total amount of energy that is consumed at that location, in both cases over a specific duration of time. If there is no generation at the location in question, the energy balance is zero. As energy generation at the location increases, the energy balance increases. The energy balance exceeds 1.0 when the amount of energy that is generated exceeds the amount of energy that is consumed.

The concept of an energy balance is useful, because any value that is greater than or less than 1.0 requires a means to export, import or store the energy that is not consumed on site. The first two of these actions are handled by the electric grid, which must be large enough and robust enough to accommodate the full range of energy imports into or exports out of a location at any point in time. The last of the three actions is handled by some type of energy storage technology, e.g., battery storage.

Energy balances are defined both spatially and temporally. For our purposes we focus on four spatial dimensions – each individual building, each electric distribution circuit, each transformer within each substation and the region as a whole – and on two temporal dimensions – the hour of maximum energy imports and the hour of maximum distributed solar energy generation (exports) over the course of the year. The temporal dimensions are important, because the design and sizing of the electric grid and its components are determined by peak conditions.

6.2.1 At the Building Level

Our basic unit of analysis is the building. As described in the prior three chapters, we have calculated for each building in the region current energy use, electricity usage at various stages of full beneficial electrification at ten-year intervals (2030, 2040 and 2050), and electricity generation assuming the maximum solar PV that can be generated. Currently, because there is very little distributed solar generation in the region, virtually 100% of all energy used in residential, commercial and industrial buildings is imported into the region or is generated at one of the region's existing fossil fuel generating plants. This begins to change as rooftop solar generation is developed, and once fully deployed, we find that certain buildings are net exporters of energy on an annual basis (i.e., over the course of the year their energy balance is greater than 1.0).

Table 6-1 shows the annual energy balances for all the buildings in the Portland Region by building type. The columns are ranges of the percent of total building energy use (including transportation) post beneficial electrification that is met by on-site rooftop solar PV on an annual basis. Not surprisingly, only about 1% of industrial buildings are able to self-generate more than 40% of their energy usages. The EUIs for these buildings measured on a per square foot basis are simply much greater than the amount of solar irradiance that strikes their roofs and can be converted into electricity using rooftop solar panels.

Commercial buildings perform a little better on this metric. As a general rule, multistory commercial buildings, such many office buildings in downtown Portland are able to generate a much smaller percentage of their annual electricity requirements, since the ratio of rooftop surface to interior square footage is low. Single story office buildings, on the other hand, do better.

Energy balances for residential buildings are mixed, depending on the aspect (compass heading), slope (pitch) and number of stories. While less than 15% can meet their total annual electricity requirements with rooftop solar PV generation, more than half are able to meet 50%.

Table 6-1 Annual Building Energy Balances – 2050

Building Type	Estimated Building Energy Balances - 2050 [Rooftop Solar PV Generation as a Percent of Building Energy Use]					
	<20%	20-40%	40-60%	60-80%	80-100%	>100%
Residential						
No. of Bldgs.	20,266	13,719	11,937	9,001	7,671	10,408
Percent	28%	19%	16%	12%	11%	14%
Cum. Percent	28%	47%	63%	75%	86%	100%
Commercial						
No. of Bldgs.	1,542	1,314	2,028	957	249	77
Percent	25%	21%	33%	16%	4%	1%
Cum. Percent	25%	46%	79%	95%	99%	100%
Industrial						
No. of Bldgs.	400	593	13	1	0	1
Percent	40%	59%	1%	0%	0%	0%
Cum. Percent	40%	99%	100%	100%	100%	100%

The annual energy balances for each of the buildings provides useful information about overall electricity flows at the building level, but they are less useful with respect to how the electric grid must be sized to meet both loads and generation requirements. For example, post beneficial electrification peak electric loads for the region occur during evening hours on the coldest days of the winter. During these hours, there is no distributed solar generation. While there may be components of the installed distributed solar systems that can provide useful services to the grid during these hours, e.g., smart inverters may assist in providing voltage support even when there is no solar generation, the fact is that distributed solar generation systems provide very little benefits vis-a-vis the need for transmission and distribution grid capacity in northern regions, where peak loads are driven by space heating requirements.

On the other hand, maximum solar generation tends to occur mid-day in the late spring or early fall on crystal clear days. Because these hours of maximum solar generation are not on either the hottest or coldest days of the year and could occur on weekend days, electric loads on the grid are not at their peak and may only be at average or even below-average levels. This is likely to create situations where the electric loads on any given circuit are not high enough to absorb the full amount of solar generation that is interconnected to that circuit. When this happens, electricity will flow "up" the circuit back to the substation – a condition called "reverse power flow". This could create serious reliability problems for the grid, if the substations are not designed to be able to accommodate such flows.

6.2.2 At the Circuit Level

Beneficial electrification and widespread distributed solar generation create two potential problems for a distribution circuit. First, distribution circuits, like all components of the electric grid, are designed to carry no more than a certain amount of electricity based on the capacity or ratings of their component parts. When electricity flows exceed those ratings, the component parts will become stressed, causing more rapid wear or complete failure. Second, distribution level substations are not currently designed to accommodate reverse power flows. When the amount of distributed generation delivered to a distribution circuit exceeds the load on that circuit, the grid is designed to disconnect the circuit, effectively islanding all generation and loads on that circuit. This will result in a localized outage, but not before serious damage might occur to electrical equipment served by that circuit.

Table 6-1 shows the maximum and minimum hourly loads on each of the 96 circuits in the Portland Area over the course of a year. The maximum and minimum loads are shown for 2020 and for increasing stages of beneficial electrification in 2030, 2040 and 2050. Currently, the average peak loads across these circuits is just over 3.2 MW, with a maximum circuit load of 7.15 MW. Further, consistent with the design of the distribution grid and the general lack of distributed generation systems in the region, there are no circuits that show negative load flows; that is, where the amount of generation interconnected to the circuit is greater than the total amount of load on that circuit during any hour.

The results in 2050, however, are very different. Post beneficial electrification in 2050, the average peak load across the 96 circuits increases to 11.7, with a maximum load on one of the circuits at 28.27 MW. Further, of the 96 circuits, 50% have peak loads in excess of 10 MW by 2050.

We do not have the conductor specifications for each segment of each of the 96 circuits, so we are not able to determine what percent of these circuits will have loads in excess of their carrying capacities under beneficial electrification. However, even without these ratings and even allowing for increased ratings and capabilities of the circuits during the winter season, many of these circuits will require reconductoring in order to meet the increased loadings.

Figure 6-2 presents the same information for maximum hourly loads in graphic form. It compares today's estimated non-coincident peak electric loadings on each of the 96 circuits in the Portland Area with that circuit's peak loadings under beneficial electrification and maximum distributed solar generation at ten-year intervals – 2020, 2030, 2040 and 2050.

The second reason why energy balances on each circuit are important is because electric distribution grids are designed as radial from a substation with electric flows assumed to flow from the substation to the end of the circuit. To the extent that distributed generation that is interconnected to a circuit generates more electricity than is being taken off that circuit by load, the power flow on the circuit will reverse, sending electricity upstream and eventually into the substation. Were a fault to occur, the circuit breakers would activate, essentially islanding the circuit. This would leave loads to be served by distributed generation that is not designed or capable of serving such loads.

There are three approaches to address this reverse power flow problem. The first is to require that the sum of total capacity of all distributed generation on a circuit be kept below the minimum load on that circuit. This ensures that generation will never exceed load and result in reverse power flows into the substation. The concern with this approach is that it constrains the amount of solar generation capacity that can be interconnected on each circuit.

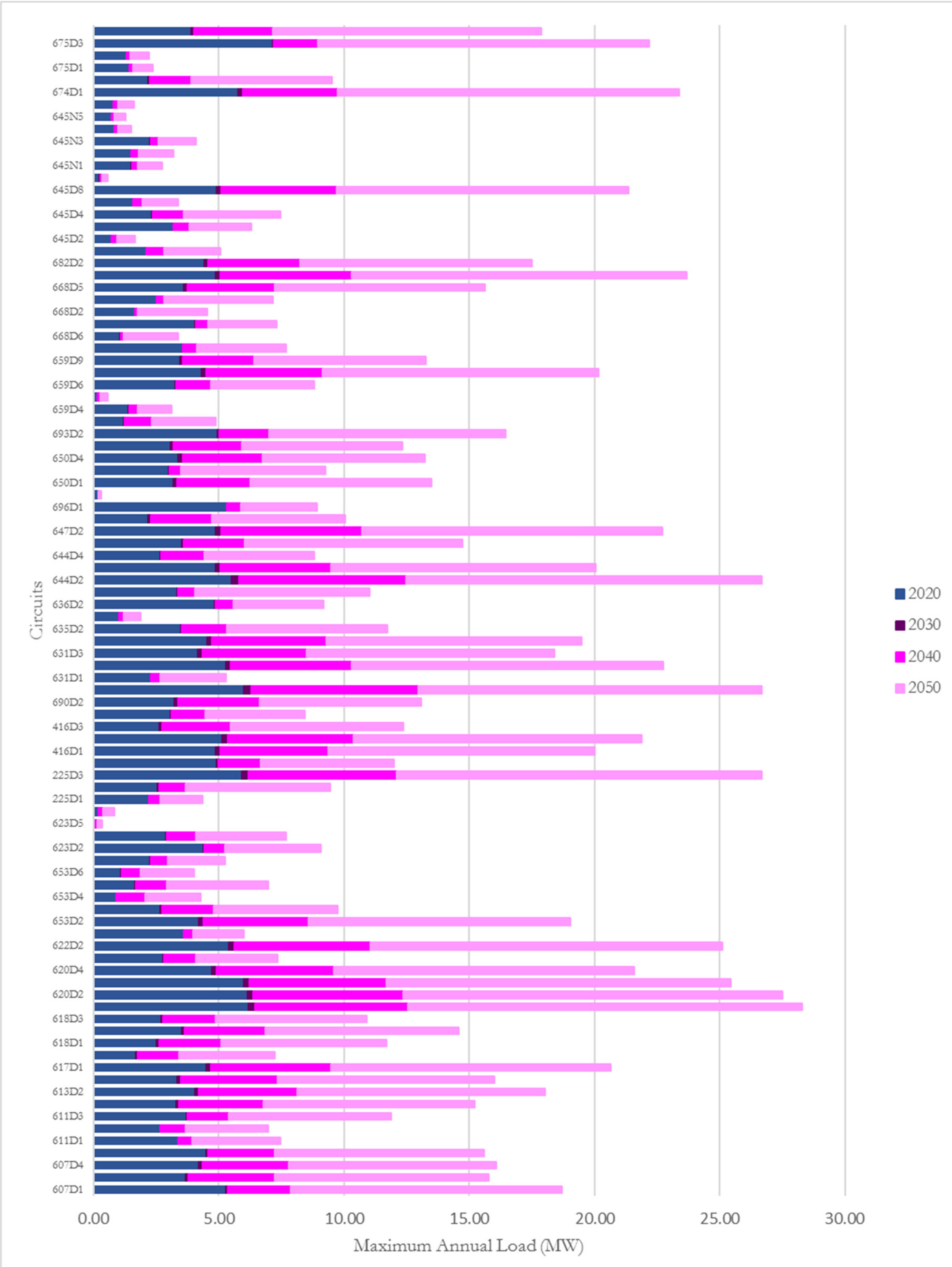
Table 6-2 Maximum and Minimum Hourly Loads by Distribution Circuit – 2020 - 2050

Circuit Table			Maximum/Minimum Loads (MW)							
Distribution Circuit	Transformer	Substation	2020		2030		2040		2050	
			Max	Min	Max	Min	Max	Min	Max	Min
607D1	No. 1	Bishop Street	5.29	2.15	5.29	2.23	7.78	-0.57	18.64	-7.85
607D2	No. 1	Bishop Street	3.66	1.33	3.80	1.41	7.22	-0.76	15.65	-6.73
607D4	No. 1	Bishop Street	4.19	1.60	4.34	1.63	7.80	0.71	15.87	-3.87
607D5	No. 2	Bishop Street	4.51	1.84	4.44	1.91	7.21	-1.33	15.58	-9.64
611D1	No. 1	Brighton Avenue	3.36	1.29	3.31	1.31	3.62	-0.15	7.08	-4.02
611D2	No. 1	Brighton Avenue	2.64	1.03	2.60	1.05	3.45	-0.57	6.60	-4.90
611D3	No. 1	Brighton Avenue	3.70	1.48	3.64	1.62	5.38	-0.53	11.89	-5.94
613D1	No. 1	Cape Elizabeth	3.28	0.99	3.42	1.05	6.77	-2.21	14.96	-10.35
613D2	No. 1	Cape Elizabeth	4.05	1.32	4.22	1.34	8.13	-1.04	17.65	-8.21
613D3	No. 2	Cape Elizabeth	3.34	0.94	3.50	0.98	7.34	-1.96	15.77	-9.28
617D1	No. 1	Dunstan	4.49	1.38	4.69	1.45	9.46	-2.14	20.33	-11.46
617D2	No. 1	Dunstan	1.69	0.58	1.77	0.60	3.41	-0.78	7.10	-4.61
618D1	No. 1	East Deering	2.51	0.85	2.61	0.91	5.08	-1.08	11.68	-5.86
618D2	No. 2	East Deering	3.52	1.25	3.65	1.27	6.87	-1.30	14.37	-8.59
618D3	No. 2	East Deering	2.69	1.10	2.78	1.16	4.86	-0.32	10.91	-4.37
620D1	No. 2	Elm Street	6.19	1.97	6.45	2.07	12.55	-3.47	27.80	-17.69
620D2	No. 3	Elm Street	6.13	2.02	6.39	2.10	12.37	-3.78	27.01	-18.94
620D3	No. 2	Elm Street	5.99	2.14	6.22	2.20	11.68	-2.82	25.10	-16.52
620D4	No. 2	Elm Street	4.73	1.49	4.93	1.53	9.60	-3.20	21.18	-15.27
622D1	No. 1	Falmouth	2.78	1.01	2.81	1.02	3.85	-0.47	6.88	-5.06
622D2	No. 1	Falmouth	5.41	1.61	5.63	1.65	11.06	-2.81	24.72	-14.29
653D1	No. 1	Fore River	3.59	1.21	3.60	1.21	3.88	1.22	5.86	1.55
653D2	No. 2	Fore River	4.21	1.48	4.38	1.56	8.57	0.40	19.02	-3.48
653D3	No. 1	Fore River	2.66	1.04	2.72	1.05	4.78	0.68	9.62	-1.75
653D4	No. 2	Fore River	0.91	0.35	0.89	0.38	2.05	-0.14	4.28	-1.38
653D5	No. 1	Fore River	1.64	0.63	1.70	0.66	2.91	0.07	6.98	-1.52
653D6	No. 2	Fore River	1.09	0.45	1.10	0.46	1.87	0.33	4.00	-0.46
623D1	No. 1	Forest Avenue	2.27	0.83	2.26	0.83	2.82	0.41	4.94	-1.37
623D2	No. 1	Forest Avenue	4.40	1.63	4.37	1.64	4.95	0.96	8.54	-1.61
623D4	No. 1	Forest Avenue	2.90	1.09	2.90	1.11	3.95	0.37	7.33	-2.42
623D5	No. 1	Forest Avenue	0.07	0.02	0.07	0.02	0.15	0.00	0.34	-0.05
623D5A	No. 1	Forest Avenue	0.18	0.06	0.19	0.06	0.37	0.02	0.80	-0.15
225D1	No. 2	Freeport	2.20	0.76	2.21	0.77	2.51	0.23	4.03	-1.80
225D2	No. 1	Freeport	2.56	0.66	2.59	0.60	3.60	-1.51	9.40	-5.95
225D3	No. 2	Freeport	5.92	1.87	6.17	1.92	12.09	-3.03	26.30	-15.91
225D4	No. 1	Freeport	4.92	1.78	4.95	1.80	6.34	-0.35	11.31	-7.11
416D1	No. 2	Gray	4.87	1.78	5.06	1.82	9.35	-3.38	19.60	-17.24
416D2	No. 1	Gray	5.15	1.77	5.37	1.86	10.39	-3.82	21.49	-18.45
416D3	No. 1	Gray	2.62	0.88	2.74	0.93	5.49	-1.16	12.13	-6.59
690D1	No. 1	Hinckley Pond	3.06	1.15	3.06	1.18	4.41	0.07	8.04	-3.69
690D2	No. 1	Hinckley Pond	3.21	1.28	3.36	1.33	6.62	-0.21	13.03	-5.07
690D3	No. 1	Hinckley Pond	6.01	1.92	6.30	2.00	12.97	-1.56	26.31	-11.89
631D1	No. 1	Lambert Street	2.28	0.87	2.25	0.89	2.43	-0.06	5.22	-2.76
631D2	No. 1	Lambert Street	5.28	1.77	5.48	1.86	10.31	-2.09	22.35	-13.03
631D3	No. 2	Lambert Street	4.18	1.36	4.35	1.39	8.52	-2.02	18.15	-11.07

Table 6-3 Maximum and Minimum Hourly Loads by Distribution Circuit – 2020 - 2050

Circuit Table			Maximum/Minimum Loads (MW)							
Distribution Circuit	Transformer	Substation	2020		2030		2040		2050	
			Max	Min	Max	Min	Max	Min	Max	Min
635D1	No. 2	Moshers	4.54	1.56	4.73	1.63	9.30	-3.27	19.20	-15.81
635D2	No. 2	Moshers	3.47	1.39	3.43	1.50	5.32	-0.57	11.73	-6.29
636D1	No. 1	Mussey Road	1.02	0.35	1.03	0.35	1.15	0.18	1.73	-0.55
636D2	No. 1	Mussey Road	4.83	1.74	4.76	1.77	5.27	0.03	8.42	-4.85
644D1	No. 2	Pleasant Hill	3.34	0.36	3.36	0.31	3.97	-1.59	10.92	-5.44
644D2	No. 2	Pleasant Hill	5.52	1.54	5.80	1.67	12.49	-3.14	26.29	-14.95
644D3	No. 2	Pleasant Hill	4.86	1.80	5.05	1.85	9.48	-2.49	19.82	-14.25
644D4	No. 3	Pleasant Hill	2.67	1.07	2.65	1.09	4.26	-0.68	8.73	-5.62
647D1	No. 2	Prides Corner	3.51	1.34	3.61	1.44	6.02	-1.49	14.71	-7.87
647D2	No. 2	Prides Corner	4.87	1.65	5.11	1.75	10.72	-2.33	22.67	-12.20
647D3	No. 2	Prides Corner	2.19	0.72	2.29	0.75	4.72	-1.41	9.96	-6.74
696D1	No. 1	Red Brook	5.31	1.79	5.32	1.79	5.68	1.30	8.38	-0.94
696D2	No. 1	Red Brook	0.17	0.06	0.17	0.06	0.19	-0.06	0.27	-0.35
650D1	No. 1	Rigby	3.20	1.26	3.35	1.36	6.25	-1.02	13.48	-6.96
650D3	No. 2	Rigby	3.01	0.40	2.96	0.41	3.49	-1.46	9.22	-5.27
650D4	No. 2	Rigby	3.38	1.40	3.55	1.47	6.73	-1.34	13.22	-8.85
693D1	No. 1	Scarborough	3.08	1.14	3.20	1.17	5.92	-1.04	12.12	-7.57
693D2	No. 1	Scarborough	4.95	1.91	4.95	2.00	6.67	-1.31	16.27	-9.25
659D13	No. 2	Sewall Street	1.20	0.43	1.24	0.44	2.32	0.00	4.80	-1.69
659D4	No. 2	Sewall Street	1.40	0.51	1.39	0.51	1.69	0.19	2.94	-1.00
659D5	No. 2	Sewall Street	0.16	0.06	0.16	0.06	0.27	-0.01	0.54	-0.26
659D6	No. 2	Sewall Street	3.28	1.23	3.28	1.24	4.52	0.27	8.41	-3.28
659D8	No. 2	Sewall Street	4.29	1.27	4.49	1.31	9.16	-1.38	19.88	-8.62
659D9	No. 2	Sewall Street	3.43	1.33	3.55	1.39	6.39	0.30	13.10	-3.99
668D4	No. 4	Spring Street	3.56	1.36	3.51	1.39	3.83	0.29	7.16	-2.96
668D6	No. 4	Spring Street	1.07	0.06	1.07	0.04	1.20	-0.58	3.37	-1.80
668D1	No. 2	Spring Street	4.06	1.42	4.03	1.43	4.36	0.79	6.79	-1.64
668D2	No. 2	Spring Street	1.63	0.38	1.61	0.39	1.72	-0.47	4.49	-2.43
668D3	No. 2	Spring Street	2.50	0.61	2.46	0.62	2.72	-0.67	7.10	-3.57
668D5	No. 2	Spring Street	3.60	1.35	3.75	1.42	7.25	-1.95	15.57	-10.33
682D1	No. 1	Swett Road	4.85	1.32	5.07	1.36	10.32	-4.16	23.33	-17.11
682D2	No. 1	Swett Road	4.40	1.64	4.56	1.68	8.24	-2.85	17.19	-15.12
645D1	No. 1	Union Street	2.08	0.76	2.09	0.77	2.74	0.62	4.89	-0.26
645D2	No. 2	Union Street	0.70	0.26	0.70	0.26	0.89	0.14	1.56	-0.39
645D3	No. 1	Union Street	3.17	1.11	3.17	1.11	3.68	0.98	6.11	0.23
645D4	No. 2	Union Street	2.32	0.94	2.30	0.96	3.51	0.14	7.46	-2.42
645D7	No. 1	Union Street	1.58	0.58	1.57	0.58	1.86	0.39	3.21	-0.53
645D8	No. 2	Union Street	4.89	1.81	5.08	1.89	9.72	0.58	21.31	-3.94
645D9A	No. 1	Union Street	0.25	0.09	0.25	0.09	0.31	0.06	0.55	-0.12
645N1	No. 3	Union Street	1.52	0.52	1.52	0.52	1.67	0.33	2.59	-0.63
645N2	No. 4	Union Street	1.49	0.56	1.48	0.56	1.73	0.45	3.07	-0.06
645N3	No. 3	Union Street	2.26	0.78	2.26	0.79	2.49	0.79	4.00	0.92
645N4	No. 4	Union Street	0.84	0.29	0.84	0.29	0.91	0.10	1.38	-0.58
645N5	No. 3	Union Street	0.73	0.25	0.73	0.25	0.78	0.19	1.19	-0.08
645N6	No. 4	Union Street	0.80	0.28	0.80	0.28	0.94	0.27	1.56	0.19
674D1	No. 1	Westbrook	5.77	2.22	5.94	2.33	9.73	-1.62	23.39	-10.67
674D2	No. 1	Westbrook	2.16	0.72	2.23	0.68	3.89	-0.84	9.52	-4.12
675D1	No. 1	Western Avenue	1.41	0.48	1.41	0.48	1.50	-0.13	2.17	-1.90
675D2	No. 1	Western Avenue	1.30	0.44	1.30	0.45	1.39	-0.17	2.01	-1.89
675D3	No. 1	Western Avenue	7.15	2.37	7.10	2.45	8.74	0.22	22.06	-5.32
218D1	No. 13	Wyman	3.91	1.24	4.02	1.18	7.08	-1.28	17.88	-6.61

Figure 6-1 Distribution Circuit Peak Loads

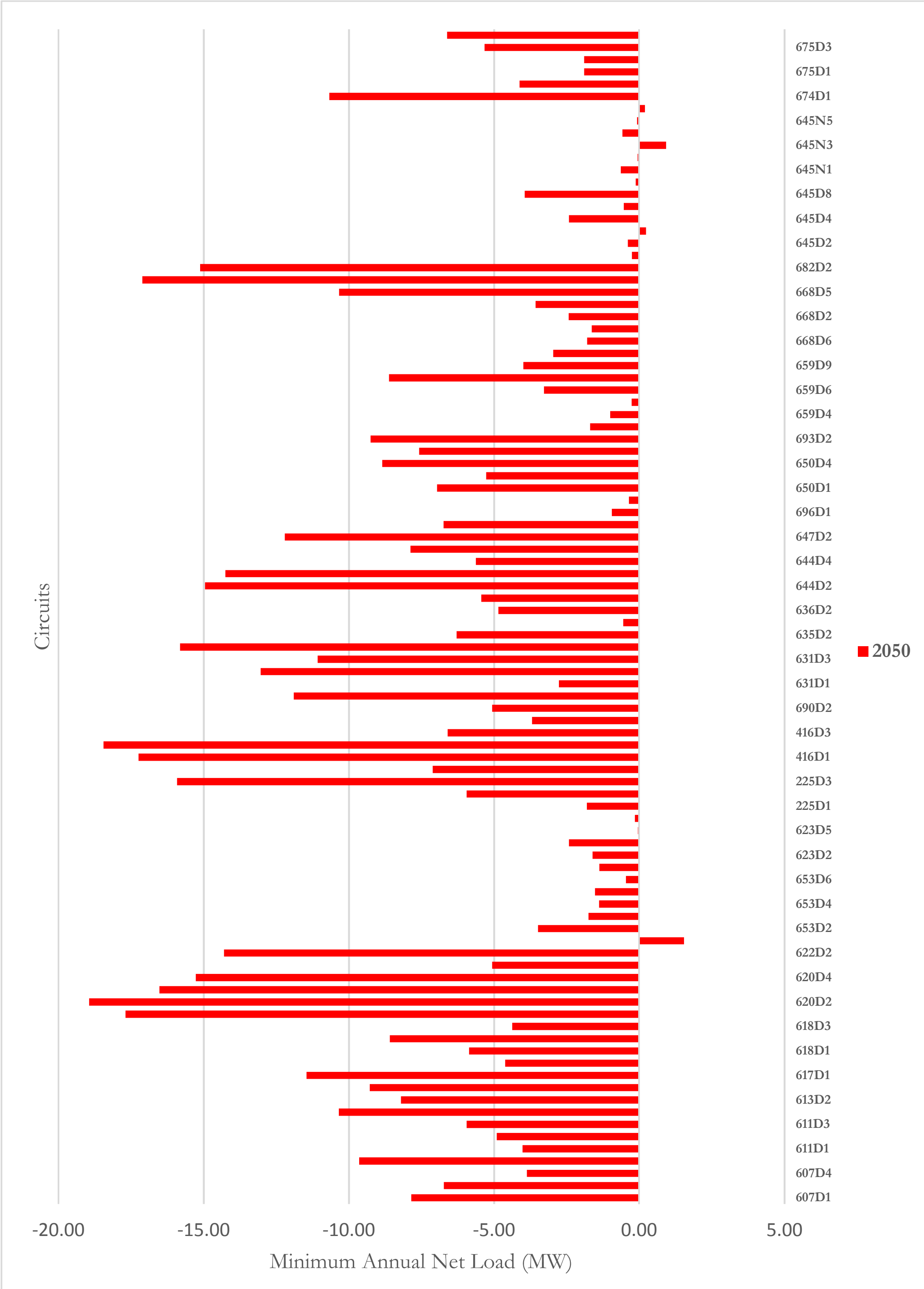


The second approach is to require that all distributed generation be equipped with reverse power relays that sever the interconnection of the distributed generation resource to the distribution circuit whenever reverse power flows are detected on the circuit near the substation. This approach relieves the artificial constraint of the first approach; however, it does so by dispatching off essentially zero-cost electricity during those hours of the year when reverse power flows are detected on the circuit and when that electricity could be used to feed the entire system.

The third approach is to remodel the substation to enable it to handle reverse power flows. In this case, surplus electricity generated on one circuit is simply routed upstream through the interconnecting transformer at the substation onto the subtransmission grid, where it is then delivered to another distribution circuit. This approach permits unconstrained solar generation on a circuit but requires increased investments in the distribution grid to accommodate this result.

To test for the occurrence of potential reverse power flows, we looked at the minimum hourly energy balances on each of the 96 distribution circuits in Table 6-1. Figure 6-3 shows the minimum net energy balance over the course of the year for each of the distribution circuits by 2050. A negative number means that the amount of distributed generation output being delivered to that circuit is greater than the amount of load on the circuit. Only 4 of the 96 circuits do not suffer from reverse power flows, and even for these 4, the net energy balance during that hour of minimum net load flows is below a couple of MW.

Figure 6-2 Reverse Power Flows on Distribution Circuits



6.2.3 At the Transformer/Substation Level

The increase in peak loads on all the distribution circuits as a result of beneficial electrification requires increased electricity flows into each distribution level substation and through transformers located at these substations to the distribution circuits. The CMP system in the Portland Area accommodates distribution circuits emanating from substations with incoming voltage at either 115 kV or 34.5 kV. We show these substations in Tables 6-2 and 6-3. Table 6-2 and Table 6-3 shows all the substations where the incoming voltage is 115 kV. Table 6-3 shows all the substations where the incoming voltage is 34.5 kV.

Table 6-2 shows the transformers within each substation that deliver electricity at distribution voltage onto distribution circuits. In some cases, the transformer serves a single distribution circuit; in other cases, there may be multiple distribution circuits fed from the same transformer. The tables also show the high-side and low-side voltage levels for each transformer and their ratings, measured in MVA. The lower level rating is without any fans providing cooling; the higher rating is with full fan cooling operating. Finally, the tables show the estimated peak loads on each transformer currently and post beneficial electrification.[38] These loads are expressed in MVA, assuming a 0.95 power factor.

Focusing first on Table 6-2, it is interesting to note that the total amount of transformation capacity across all transformers, even at the higher rating levels, is well below the peak electric loads that will need to be served post beneficial electrification in 2050. The total transformation capacity is 241 MVA compared to loads of just over 380 MVA. The problem is most acute at the Elm Street, Hinckley Pond Pleasant Hill and Prides Corner substations.

These capacity shortfalls are shown graphically in Figure 6-4. This figure shows the maximum loadings on each transformer as a percentage of its higher value capacity rating. While there are a few instances in which total 2050 loads are within the range of the ratings of these transformers, most cases show loads well in excess of those ratings, as noted above. Further, the loads begin to exceed ratings sometime in the 2030s.

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[38] Where a transformer serves multiple distribution circuits, the load levels shown are the coincident peak loads across all such distribution circuits. The load levels shown as "Subtotals" and "Grand Totals" for 115/12.5 kV and 34.5/12.5 kV are the sums of the non-coincident peaks across all substations.

Table 6-4 Transformer Capacities and Loads – 115 kV Substations

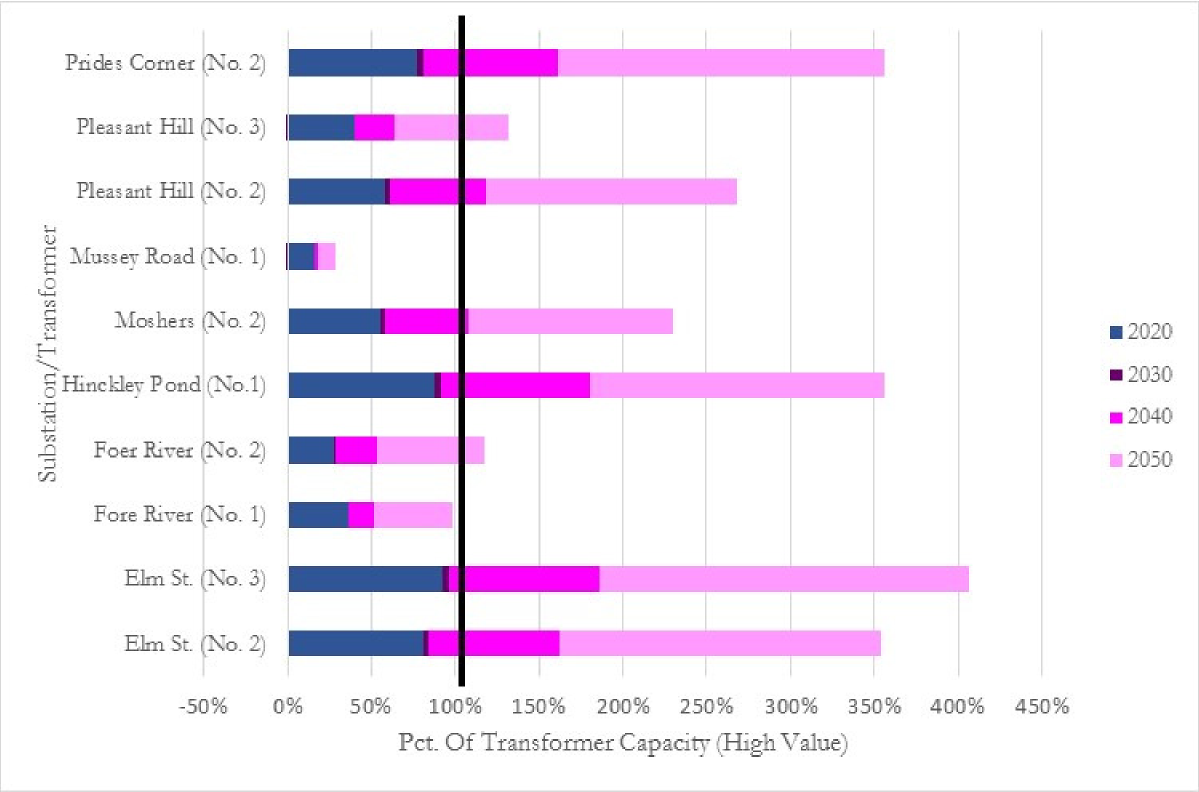
Transformer Capacities and Loads - 115 kV and 34.5 kV Substations*
[* At 95% Power Factor]

	Transformer Voltage (kV)	Transformer Capacity		Maximum Loads			
				2020	2030	2040	2050
Transformer Identifier	**High/Low**	**MVA**	**MVA**	**MVA**	**MVA**	**MVA**	**MVA**
115/12.5 kV Substations							
Elm Street							
No. 2 Bank	115/12	12.00	22.00	17.81	18.52	35.61	77.99
No. 3 Bank	34.5/12	5.00	7.00	6.46	6.72	13.02	28.43
Fore River							
No. 1 Bank	115/12	12.00	22.40	8.13	8.14	11.52	22.05
No. 2 Bank	115/12	12.00	22.40	6.13	6.38	11.90	26.31
Hinckley Pond							
No. 1 Bank	115/12	10.00	14.00	12.33	12.86	25.21	49.86
Moshers							
No. 2 Bank	115/12	10.00	14.00	7.76	8.13	15.10	32.26
Mussey Road							
No. 1 Bank	115/34	20.00	37.00	6.16	6.09	6.76	10.63
Pleasant Hill							
No. 2 Bank	115/12	12.00	22.40	13.05	13.61	26.51	60.03
No. 3 Bank	34/12	5.00	7.00	2.81	2.79	4.48	9.19
Prides Corner							
No. 2 Bank	115/12	10.00	14.00	10.83	11.32	22.58	49.83
Sewall Street							
No. 1 Bank	115/12	12.00	22.40	0.00	0.00	0.00	0.00
Spring Street							
No. 3 Bank	115/12	10.00	14.00	0.00	0.00	0.00	0.00
No. 4 Bank	115/34	12.00	22.40	4.69	4.62	4.94	11.05
Subtotal - 115/12.5 kV Substations		**142.00**	**241.00**	**96.16**	**99.19**	**177.63**	**377.62**

Notes:

1. Sewall Street No. 1 Bank provides a secondary source of electricity supply to those circuits fed off Sewall St No. 2 Bank (34/12.5 kV Bus). All of the load on these circuits has been assigned to the No. 2 Bank transformer.
2. Spring Street No. 3 Bank provides a secondary source of electricity supply to those circuits fed off Spring St. No. 2 Bank (34/12.5 kV Bus). All of the load on these circuits has been assigned to the No. 2 Bank transformer.

Figure 6-3 Max. Loads by 115/12.5 kV Transformer – 2020 – 2050 as a Pct. of High Ratings



The capacity shortfall is as pronounced for the 34/12.5 kV transformers in the region as shown in Table 6-4. In a number of cases, peak load levels by 2050 are more than twice the higher ratings of the transformers. A case in point is the No. 1 Bank transformer at the Bishop Street substation. This transformer has a high-level rating of 22.4 MVA; however, post beneficial electrification peak load that needs to be served through this transformer is 52.8 MVA.

Figure 6-5 presents the same information graphically. As with the 115/12.5 kV transformers noted above, peak load levels on a number of the transformers at the distribution level will exceed their high value ratings during the 2030s.

Table 6-4 Transformer Capacities and Loads – 34.5 kV Substations

Transformer Capacities and Loads - 34.5 kV Substations*
[* At 95% Power Factor]

34.5/12.5 kV Substations	Transformer Voltage (kV) High/Low	Transformer Capacity MVA	MVA	Maximum Loads 2020 MVA	2030 MVA	2040 MVA	2050 MVA
Bishop Street							
No. 1 Bank	34/12	12.00	22.40	13.15	13.63	23.94	52.80
No. 2 Bank	34/12	5.00	7.00	4.75	4.67	7.59	16.40
Brighton Avenue							
No. 1 Bank	34/12	10.80	20.20	10.22	10.05	12.55	25.57
Cape Elizabeth							
No. 1 Bank	34/12	7.50	10.50	7.72	8.04	15.68	34.32
No. 2 Bank	34/12	5.00	7.00	3.51	3.68	7.72	16.60
Dunstan							
No. 1 Bank	34/12	7.50	10.50	6.51	6.80	13.55	28.87
East Deering							
No. 1 Bank	34/12	5.00	7.00	2.65	2.75	5.35	12.29
No. 2 Bank	34/12	7.50	10.50	6.43	6.66	12.35	26.61
Falmouth							
No. 1 Bank	34/12	7.50	10.50	7.92	8.22	15.20	32.58
Forest Avenue							
No. 1 Bank	34/12	12.00	22.00	10.25	10.18	12.80	22.85
Freeport							
No. 1 Bank	34/12	7.50	10.50	7.39	7.27	9.79	21.22
No. 2 Bank	34/12	10.00	14.00	7.78	8.06	14.90	31.38
Gray							
No. 1 Bank	34/12	7.50	10.50	8.17	8.53	16.71	35.38
No. 2 Bank	34/12	5.00	7.50	5.13	5.32	9.84	20.63
Lambert Street							
No. 1 Bank	34/12	7.50	10.50	7.07	7.35	13.07	28.93
No. 2 Bank	34/12	5.00	7.00	4.40	4.58	8.97	19.10
Red Brook							
No. 1 Bank	120/36	20.00	37.00	5.77	5.78	6.18	9.08
Rigby							
No. 1 Bank	34/12	5.00	7.00	3.37	3.52	6.58	14.19
No. 2 Bank	34/12	7.00	10.50	6.14	6.29	9.98	23.62
Scarborough							
No. 1 Bank	36.2	10.00	14.00	8.04	8.08	13.13	29.89
Sewall Street							
No. 2 Bank	34/12	12.00	22.40	13.40	13.87	25.25	52.13
Spring Street							
No. 2 Bank	34/12	7.50	10.50	11.25	11.09	15.36	34.58
Swett Road							
No. 1 Bank	34/12	10.00	14.00	9.75	10.14	19.54	42.65
Tank Farm							
No. 1 Bank	34/2.4	3.80	4.70				
No. 2 Bank	34/2.4	7.50	10.50				
Union Street							
No. 1 Bank	34.5/12.47	12.00	22.00	7.45	7.45	9.04	15.53
No. 2 Bank	34.5/12.47	12.00	22.00	7.83	8.15	14.76	31.86
No. 3 Bank	34.5/11.5	12.00	22.00	4.74	4.74	5.17	8.19
No. 4 Bank	34.5/11.5	12.00	22.00	3.29	3.28	3.75	6.33
Westbrook							
No. 1 Bank	36.2/13.2	10.00	14.00	8.32	8.56	14.33	34.64
Western Avenue							
No. 1 Bank	34/12	12.00	22.00	9.86	9.76	11.72	26.65
Wyman							
No. 13 Bank	34/12	3.80	5.30	4.12	4.24	7.45	18.82
Subtotal - 34.5/12.5 kV Substations		**278.90**	**447.50**	**216.36**	**220.75**	**362.25**	**773.69**
Grand Total - All Substations		**420.90**	**688.50**	**312.52**	**319.94**	**539.87**	**1,151.31**

Figure 6-4 Max. Loads by 34/12.5 kV Transformer – 2020 – 2050 as a Pct. of High Ratings

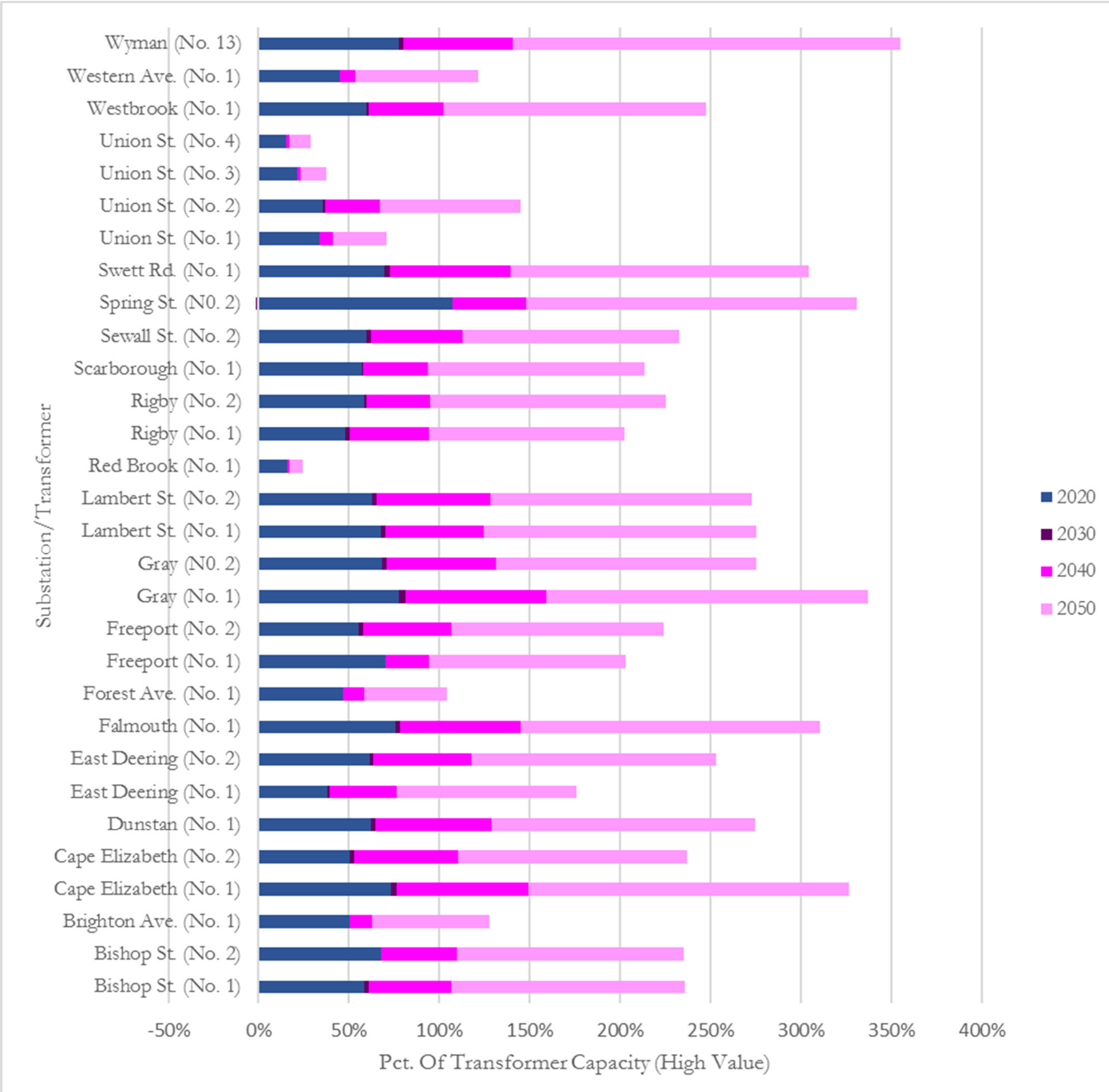
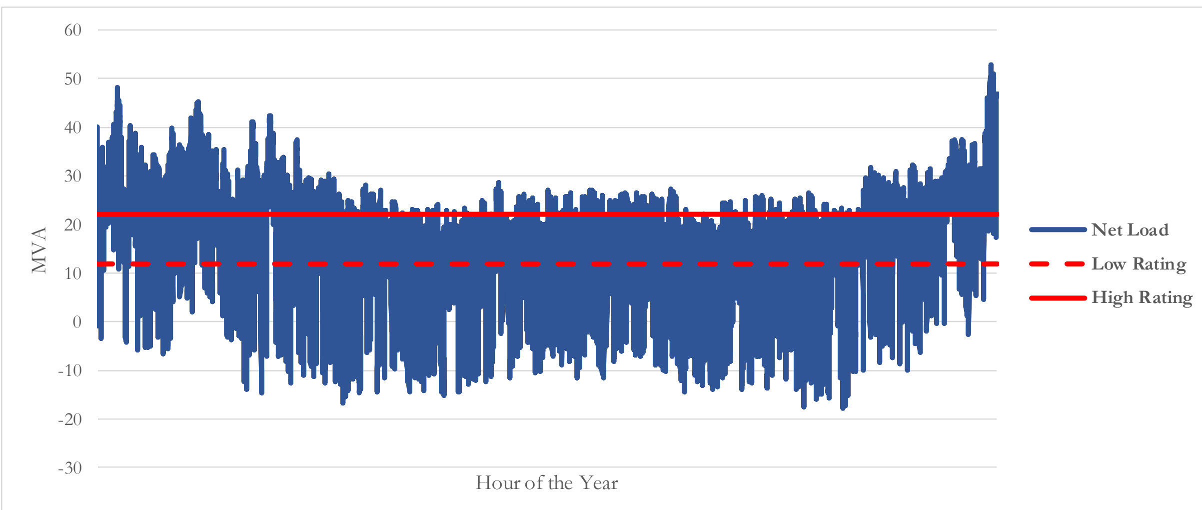
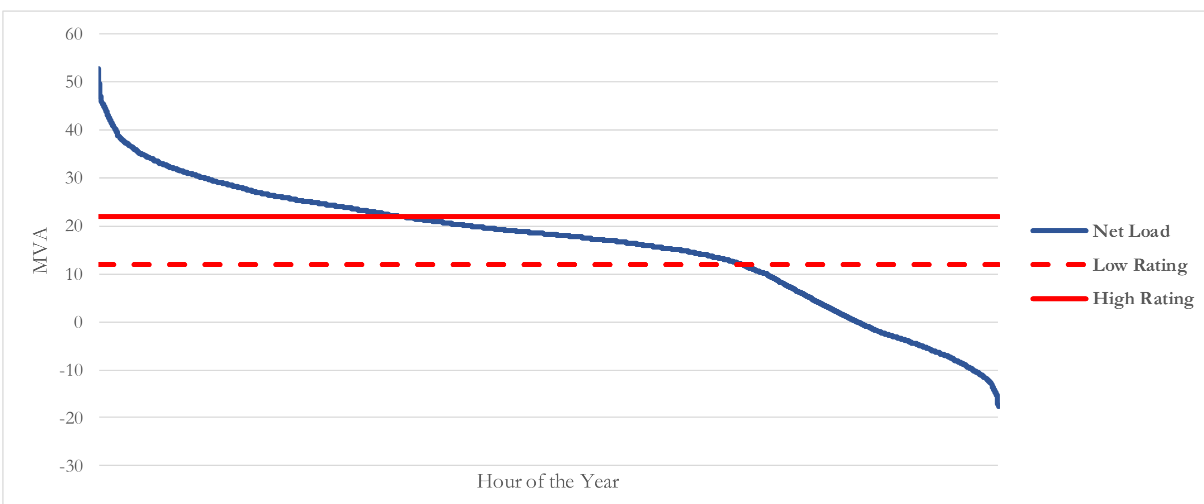


Figure 6-6 shows the hourly load levels on the Bishop Street No. 1 transformer post beneficial electrification in 2050. The load levels through this transformer are well above the ratings for most hours of the year. The top graph in Figure 6-6 shows estimated hourly loads through the No. 1 Bank transformer at Bishop Street substation post beneficial electrification, beginning midnight January 1 and ending midnight December 31. The bottom graph shows the load duration curve for the transformer loads. Also shown on both graphs for reference are the low- and high-level capacity ratings for the transformer (12/22.4 MVA). The load duration curve shows that loadings on the transformer are in excess of the high-level rating for about a third of the hours in the year. The upper graph shows that, while hourly loadings during the winter season are almost all in excess of the high-level rating, there are many hours every month in which loads exceed the high-level rating. Importantly, these hours include summer evening hours when there is no solar generation and high ambient air temperatures place stress on transformer operations.

Figure 6-5 Load Levels v. Capacity – No. 1 Bank – Bishop Street Substation





6.2.4 At the Regional Level

We next look at the energy balance for the region. Figure 6-7 shows the net loads across the region each hour of the year. The top graph shows estimated 2020 load flows; the bottom graph shows estimated 2050 load flows, assuming beneficial electrification and full build-out of distributed solar generation. Total gross loads in 2050 are 4,128 GWh; total gross generation is 1,590 GWh. Accordingly, on balance over 2050, the region will be a net energy importer of about 2,538 MWh. However, hour-by-hour energy flows will range from a maximum import demand of just less than 1,086 MW to a maximum export of 533 MW. These two graphs describe very different electric conditions from those that exist today, and these conditions will require very different electric grids.

CMP has argued in its Needs Assessment of the Portland Region that the existing transmission grid fails to meet grid reliability requirements at current peak load levels. The portion of the grid north of Portland is weak, while the underlying 34.5 kV system in the southern portion does not have sufficient capacity to handle loads in the event of a 115 kV outage. When load levels are increased to those levels under full beneficial electrification, the existing grid fails at every level at virtually every point on it. If, as CMP has determined, the transmission grid in the region is not capable of handling a peak load of 420 MW, it will be woefully inadequate when net electricity loads across the region reaches levels in excess of 1,100 MW on cold winter evenings.

6.3 Storage

None of the modeling underlying our estimates of energy balances at any level of the electric grid includes any consideration of energy storage technologies. Intuitively, we would expect storage to be capable of addressing some of the energy balance mismatches by absorbing excess energy generated by the distributed solar PV rooftop systems (essentially functioning as load during the charging cycle) and returning it to the grid during evening and nighttime hours when loads exceed solar generation. To the extent that storage is able to play this role, it may be possible to reduce the required capacity of the grid and/or reduce investments in the distribution grid necessary to avoid the islanding scenarios that can arise when there are reverse power flows on distribution circuits. Upon closer examination, however, storage may provide less value as a means of addressing energy balance situations.

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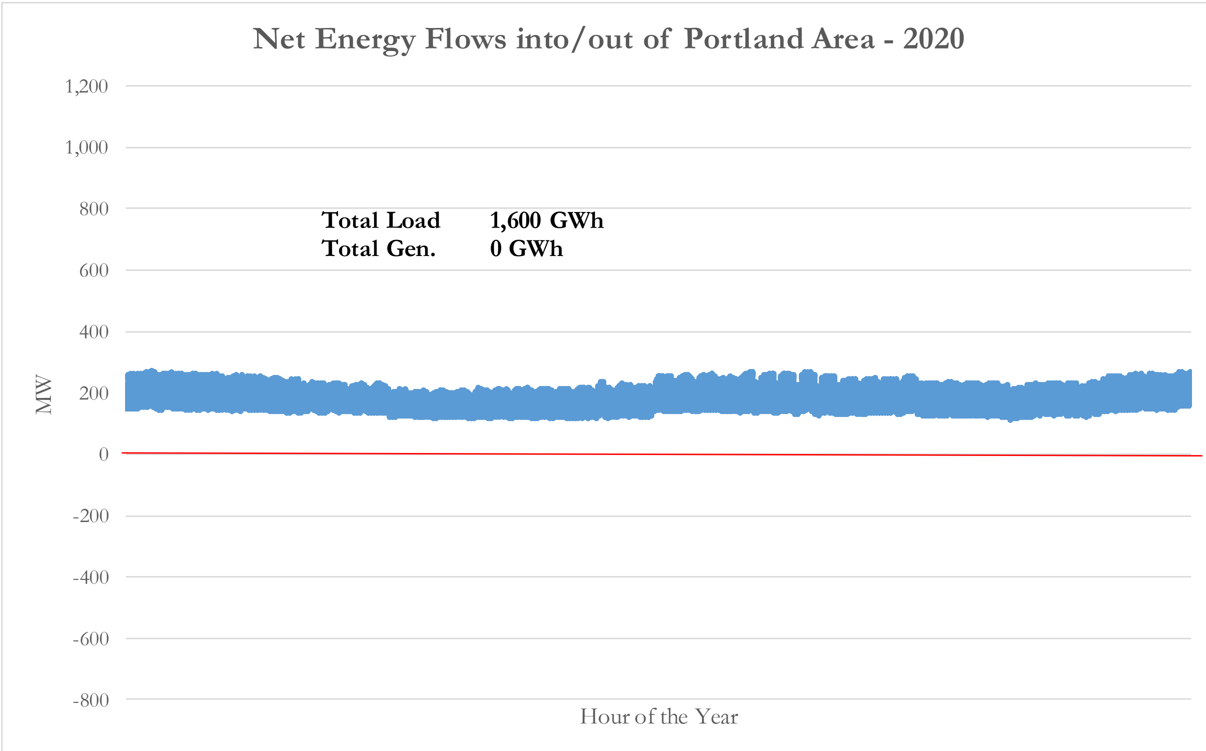
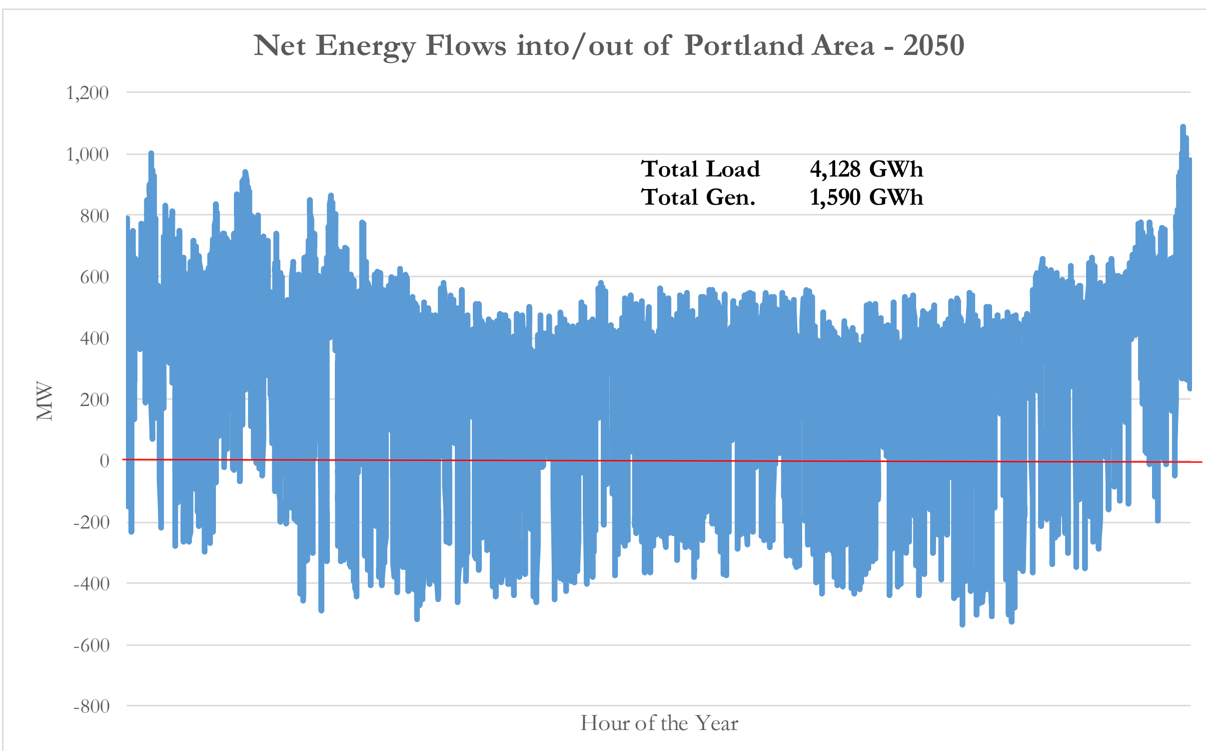
Figure 6-6 Hourly Energy Balances for the Portland Area





First, consider the regional energy balance. Figure 6-6 shows that the transmission grid in the Portland Region must be able to support electricity import flows of more than 1,000 MW during peak winter hours. A portion of these power inflows can be offset by storage facilities located within the region. These facilities can be of any form, including batteries, electric thermal storage, flywheels, but in order to offset electricity imports, they must be physically interconnected to the grid in the region or deliver electricity use offsets to buildings located in the region. This location requirement could present a hurdle to grid-scale storage solutions that require large footprints such as battery storage systems.

An alternative are smaller distributed storage options such as home battery back-up devices and passenger vehicle batteries. Assuming a centralized control system can be developed to provide management and operational control of thousands of such distributed storage facilities, it will still be necessary to obtain the consent of the owners of these systems to use them for this purpose. This may not be easy. The problem is that peak loads are likely to occur during a prolonged cold wave – at precisely the time residents and businesses will be most reliant on electric service for building heat. Whether many will allow the grid to drawn down their small distributed battery storage capacities during the coldest evenings in the winter, thereby leaving them fully exposed to power outages, is an open question.[39]

A related issue will most certainly affect peoples' willingness to allow a central grid operator to drawn down the electric energy stored in vehicle batteries. Because these draw-downs are likely to occur during periods of very cold weather, the electricity stored in vehicle battery systems at those times is significantly derated in terms of the useful miles it can provide its owner. This limits the range the owner could subsequently travel in the event of an emergency. Further, to the extent any power outage is widespread across the region, the owner will have difficulty recharging his or her vehicle, because no charging station will be able to afford to install battery storage on the scale necessary to provide charging capacities in the event of a grid outage.[40]

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[39] It is important to note that in a zero-carbon economy, residents and businesses will not have backup propane or diesel generators to provide electric service during grid outages. While there may be no laws prohibiting such systems, the upstream infrastructure and delivery requirements to drill for, refine, store and deliver the fuels would be uneconomical.

[40] Consider a typical gas station with two underground 20,000 gallon storage tanks that are half full. Assuming an average of 20 mpg across the vehicles using this station, the stored gasoline can provide 400,000 miles of travel, which it can do with a backup generator in the event of a power outage. To provide the same travel miles during a cold winter period when the average EV is achieving 2 miles/kWh, the station would have to have a 200 MWh battery storage system. To put this in perspective, the battery system Tesla installed in Australia a few years ago has the ability to store 129 MWh of electricity and covers an area bigger than a full city block.

Ultimately, whether people allow a central grid operator access to its stored electricity in any form will depend on the price offered. The prior discussion suggests that the price will need to be quite high for the grid operator is to acquire access to much of the available storage capacity. The key question will be whether the price is less than the costs of the incremental grid capacity avoided.

Next, consider conditions of reverse power flows on any individual circuit. As we discuss further in the next chapter, reverse power flows in and of themselves do not create problems on the grid. What reverse power flows indicate, however, does. To see this, consider first the case where reverse power flows on a circuit do not exist. The absence of reverse power flow conditions on a circuit means that the amount of distributed solar PV generation interconnected to the circuit is always less than the amount of load served by the circuit. In this situation, any fault that results in an isolation of the circuit from the grid will collapse the circuit. The solar generators will not be able to sustain the load, voltage levels will fall, and each solar system will cease generating electricity, thus protecting any electrical equipment powered by the circuit.

On the other hand, when a reverse power flow occurs on a circuit, it means that the amount of distributed solar PV generation interconnect to the circuit exceeds loads served by the circuit. In this situation, if there is a fault at the substation that isolates the circuit from the grid, the circuit may not go down but instead may be supported and carried by the solar PV generation – the circuit may function as an electrical island in an unmanaged fashion. This can create serious problems. Because of the intermittency of the solar generation from multiple systems interconnected to the grid each operating on its own, the collective capability of those systems to follow load in a stable and reliable manner is highly uncertain. Absent some form of centralized control on the circuit, that mimics the function of an ISO or other grid manager, voltage fluctuations and instability are likely and can cause damage to electrical equipment connected to the circuit. Storage systems interconnected to the same circuit can provide some stabilizing effect on the islanded circuit, just as they do on the grid as a whole, but to do so requires some form of passive power management that involves communication and control feedback loops for the distributed solar PV and storage systems. These may cost more than alternatives that simply prevent islanding of any circuit by dispatching off all generation immediately upon isolation of the circuit from the grid.

We are certain there is a critical role for storage to play in reallocating energy across different time periods to meet electric loads. We are less certain that storage will play a major role as a transmission and distribution system capacity alternative. We note that this is an area that warrants significant research, modeling and analyses.

Chapter 7 - Electric Grid Design

7.1 Introduction

The purpose of the electric grid is to interconnect electric generators with electric consumers. The design and structure of the grid is constantly changing in response to changing generation technologies and the location of generating plants, on the one hand, and the location of electric consumers and how those consumers use electricity, on the other. It is also impacted by performance standards with respect to reliability and stability, each of which has become stricter over time, as electricity has become an essential utility in today's world. However, all the changes that have impacted the electric grid over the past century pale in comparison to those that must occur if we are to achieve a zero-carbon economy through beneficial electrification and deep decarbonization of electricity generation.

The previous chapter illustrates the inadequacies of the current electric grid in three critical respects. First, the distribution grid has far too little capacity to handle the amount of electricity that will flow to residential, commercial and industrial consumers as they convert their transportation vehicles, space heating and process requirements from distillate fuels and natural gas to electricity. Second, the existing grid will be unable to serve distributed rooftop solar generation as it is developed across all buildings. The distribution grid is not designed to accommodate multi-directional power flows and not equipped with the intelligence and capabilities to manage tens of thousands of small-scale electric generation plants and orders of magnitude more load centers and battery storage devices. Finally, the very low energy balance ratios that will exist even with full build-out of distributed rooftop solar systems will require substantially more energy imports into urban centers that, in turn, will require major increases in transmission capacities.

We look at each of these three grid deficiencies in this chapter; but first we focus on load forecasting and how load forecasting methodologies must adapt to incorporate changes in how we will use electricity in the future and advances in how such electricity use is measured.

7.2 Electricity Load Forecasting

The planning, design and buildout of any electric grid begins with a forecast of electricity loads. Since many components of electric grids are capital intensive and have fixed capacities, efficient and cost-effective planning of electric grids requires forward looking load forecasts of a minimum of ten (10) years, and for some components, even longer. It is simply not cost-effective to meet current load with a specific transformer or circuit conductor if future demands on the equipment are likely to exceed capacity ratings in the near future. In that case, it may be preferable to install equipment with higher capacity ratings to accommodate future load growth, even though some of this capacity may be excess capacity and not used today.

Techniques and methodologies for forecasting electric load have changed significantly over the past 100 years as the underlying factors impacting electricity use in the country have changed. During the initial build-out of localized transmission and distribution grids in the early 1900s, load was driven largely by electric lighting, and specifically how many existing homes, businesses and public facilities could be interconnected to the grid. Forecasting demand for electricity was less important than extending the distribution grid to increasing numbers of end-users. During this initial period of electrification, the overriding objective was to interconnect buildings of all types to bring electric service to as many businesses and people as economically feasible. The use of the grid by those end-users was of secondary concern, except for certain high-intensity end-users.

This all changed following the end of World War II. In the immediate post war years, electricity demand was driven by three factors – (a) the suburbanization of housing and related commercial establishments, (b) the electrification of residential appliances (e.g., clothes washers and dryers, stoves, air conditioning, space heating and hot water systems) and commercial HVAC systems and the diffusion of those appliances and systems across the existing and new housing and building stocks, and (c) the electrification of production processes. Unlike the first wave of electrification that drove the development and dissemination of the electric grid, this second wave of electrification resulted in an expansion of electricity demand at virtually each location on the grid. Electricity demand became less a function of the number of buildings interconnected to the grid than to the end-uses of electricity at each point of interconnection.

This meant that the relative importance of macroeconomic variables in driving electric loads gave ground to variables measuring the market penetration of end-use technologies and equipment powered by electricity. As a result, utilities undertook spatial and temporal studies of how various end-use equipment consumed electricity and then how these types of equipment would be adopted by customers across the grid. The new electricity forecasting models reflected underlying trend lines related to overall economic growth within a utility service territory. These trend lines, however, were modified by forecasted penetration of key end-uses such as commercial HVAC systems, residential air conditioning, and washers and dryers and the results of studies showing how these end-uses consumed electricity. Perhaps not surprisingly, given that the relative price of electricity fell during this period, these forecasting models generally did not include any price terms. The concept that demand for electricity was responsive to the price of electricity was generally not a factor in estimating future electricity demands.

The consequence of the failure to consider the price of electricity in forecasts of electricity loads became apparent in the aftermath of the oil embargoes of the 1970s and major cost overruns in nuclear plant construction during the 1980s. The forecasts of electricity demand that were used in part to support the buildout of new generation plants were proven wrong. As electricity prices rose, demand for electricity slowed. Initially, this slowdown was driven largely by price effects – what economists refer to as the price elasticity of demand. People responded to higher prices by using less electricity. Over time, of course, the market (with help and encouragement from government regulations and financial incentives) responded with new technologies and equipment that was more energy efficient, so much so that for many utility service territories, the increase in efficiency and conservation has offset the underlying macroeconomic driven trend lines. Load forecasting models have adapted to this situation by incorporating economic growth/income variables, price variables and the impacts of energy efficiency and conservation, although many such models have tended to underestimate the load suppression effects of this last factor.

The present danger with current load forecasting models is that they will repeat the errors of the past by not adapting to changed market conditions and specifically to the next wave of electrification – beneficial electrification of transportation, space heating and industrial and commercial processes. As we have shown in the Portland Area and across the State of Maine, electricity use will increase three- to four-fold as we convert these three sectors to electricity. The speed at which this occurs will be the primary factor that determines electricity load growth over the next thirty years. Further, the geospatial locations of the people and businesses that are leaders in this conversion will determine where new transmission and distribution plants will be required, which, in turn, will define the physical layout and requirements of tomorrow's electricity grid. These factors must become the building blocks for electricity load forecasting models, as we return to models designed to build from the bottom-up rather than from the top-down.

Fortunately, the design and development of the next generation of electricity load forecasting models can be built on a data and information system infrastructure that is made possible by advanced metering technologies, so-called "big-data" systems, advances in artificial intelligence and networked information systems. We don't have to sample 2,000 Maine households to measure hourly consumption of electricity that can then be applied statistically to all 700,000 plus households in Maine. CMP's and Emera Maine's smart meters already measure, capture and store this data for virtually all 700,000 households. We don't have to guess the levels of peak power flows on distribution circuits, through transformers and at substations. Advanced metering and communications systems embedded in the grid are available to provide this information. We don't have to build electricity forecasting models based on aggregate measures of growth, electricity price projections and technology penetration. We can build electricity use models from the fundamental building block of the customer meters that can then be used to estimate hourly (or even finer time intervals) power flows across circuits, through transformers, into and out of substations and ultimately up to large high-voltage power flows on major transmission lines. Once these electricity use models are built, forecasting models can apply estimates of temporal and spatial expansions of beneficial electrification of the various sectors of the economy to predict electricity loads, not just for the aggregate utility service territory, but for subregions of the utility's service territory down to individual neighborhoods. This is the "stuff" upon which the design and development of the next generation of the electric grid must be based.

Based on our work in the Portland Area and a similar type of analysis for the State of Maine, we believe that the process of forecasting electric loads used by CMP and Emera Maine and by others involved in the planning and design of Maine's electric grids needs to be completely overhauled and rebuilt from the bottom-up, as described above. We are beginning to see some recognition of the mismatch between the results of current forecast models and the policy goals and laws and regulations of the New England states creep into load forecasts being done by ISO-NE. These efforts, however, are at best in the earliest of stages and reflect ad hoc or piecemeal add-ons to the forecasts produced using the traditional models at ISO-NE. We strongly recommend that the Maine Public Utilities Commission initiate an open, non-adjudicatory proceeding for the purposes of developing new electricity load forecasting methodologies. We do not believe that this initiative should act to suspend transmission and distribution projects that are currently under consideration or in the immediate pipeline. Instead, as an interim step, we recommend that these projects be assessed in terms of the likelihood of being components of a major expansion of the grid in the electric region in which they are located at some point over the next 20 years. If it is reasonable to conclude that a specific project is not – that it will be inadequate to meet loads under beneficial electrification, then the project should be suspended and reconsidered. We illustrate how this process could be applied in the Portland Area in the next chapter.

7.3 Expanding the Distribution Grid

Figure 6-2 shows that most existing distribution circuits in the Portland Area have excess capacity, and assuming conductor ratings in the 7-10 MVA range, can meet increased electricity flows as a result of beneficial electrification into the mid-2030s. Beyond this time period, however, the existing circuit configuration is simply inadequate to meet anticipated electricity loads. If the distribution conductor sizes and their ratings remain in the 7-10 MVA range, we would need to roughly double the number of distribution circuits to meet loads and retain some excess capacity to accommodate load growth or customer relocations. However, the fact that increased heating loads are the primary factor driving the need for additional distribution circuit capacity and that these loads occur in the winter and not just on any winter day, but on the coldest winter day means that conductor ratings for each given conductor size are likely higher.

Figure 4-6 offers some insight into the factors that will drive the number and sizing of distribution circuits post beneficial electrification. Relative to current peak loads of 271 MW that occur during the summer, winter peak loads by 2050 will be 1,100 MW, while summer peak loads will be around 600 MW. Depending on the winter and summer ratings for conductors at ambient air temperatures of around -10ºF and 95ºF, respectively, individual circuits in the region may be winter or summer peaking. In either case, the relationship between winter loadings, ambient air temperatures and grid component ratings is an important factor and needs to be carefully considered as heating becomes electrified.

A doubling of the number of distribution circuits over the next 30 years will require significant capital investments. Further, as shown in Table 4-1, the annual capacity factor of Maine's electric grid will fall from around 71% in 2020 to 43% in 2050, largely as a result of the increase in heating loads during the winter season. Together, these factors will lead to rate increases and more money being spent by Maine families and businesses on electricity. However, these rate increases and higher spending will be offset – perhaps entirely if we are careful in how we organize and manage this transition to electrification – by reductions in spending on fossil fuels.[41]

Increases in the carrying capacities of the distribution grid will require more miles of distribution circuits and more and/or larger sized distribution substations. We would not expect to see more than one distribution circuit in front of each home or business, so in this sense, the basic building block of the distribution grid will not look much different tomorrow than it does today to the typical Mainer. What will change is that the circuits will need to be reconductored to support higher peak loads; there will need to be more circuits with longer runs back to the existing substation locations; the number (not just the capacities) of substations will need to increase; or most likely, a combination of all three. Assuming we don't move to more undergrounding of distribution lines, we are likely to see taller telephone poles to provide improved reliability and increased space reserved on these poles to carry more than one distribution circuit.

The land-use impacts of an expanded distribution grid are most likely to occur as a result of expansions of existing distribution substations and/or the construction of new substations. This could present a challenge to utility planners, given the lack of available space in urban centers and the general opposition to new electrical substations in residential neighborhoods. In either case, we believe it is prudent for utilities to consider acquiring for future use a number of parcels of land across their service territories to site new electrical distribution substations and to work with towns to ensure that their land-use plans, zoning and building codes accommodate the types of electrical grid upgrades and expansions that will be necessary to support beneficial electrification and increased distributed generation.

One consideration that could further increase the required size of the distribution grid is a redesign of that grid from a radial system to a networked system. It is useful to characterize the current distribution grid as a radial grid in which each load is served through only one physical delivery path. This is the situation for the majority of CMP's service territory, although we understand that CMP does have some limited networked distribution circuits located in downtown Portland.

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41 While this may be accomplished in the aggregate, there will be many individual residents and businesses whose energy use is electricity intensive. They are likely to see an increase in their overall energy costs even if overall spending on energy remains flat in real terms.

Network designs provide improved reliability to distribution grids by enabling loads to be served through a second path and perhaps multiple paths. This increased reliability, however, comes at a cost. Each segment of each path of delivery must be able to support all possible flow configurations within the network. Unlike in radial designs where the ends of radial circuits support smaller loads and therefore can be built for lower electricity flows, a networked system must be able to support the maximum flow on all its components. In practice, this requires larger capacity conductors, more reclosers and generally shorter circuit run lengths, especially under beneficial electrification, where overall flows are much higher than they are today.

7.4 Accommodating Multi-Directional Power Flows

Beneficial electrification drives the need to expand the grid to deliver more electricity to all end-users. Deep decarbonization, through the development of renewable generation and in particular distributed generation, creates a different set of problems for distribution grids. Figure 6-3 shows that virtually all the distribution circuits in the Portland Area will experience reverse power flows by 2050 as distributed roof-top solar systems are built out across the region, thus triggering islanding concerns across the entire distribution grid. This is true even though in total this solar generation will meet less than 40% of the region's electricity requirements in 2050.

This, of course, only deals with one form of distributed generation. As a result of a legislatively mandated expansion of net metering opportunities and utility purchases of distributed generation output, we are currently seeing an explosion of proposed distributed ground-mounted solar projects, all less than 5 MW in total capacity. When many project developers seek to interconnect relatively small-scale (less than 5 MW of capacity) solar PV systems to distribution circuits, issues related to conductor, transformer and substation capacities as well as system reliability due to pervasive reverse power flows and potential islanding concerns are impacting the electric grid now, not 20 years from now.

At the heart of the matter is the question of who pays for upgrades to utility transmission and distribution systems that will be necessary for the state to achieve its overall emission target reductions over the next thirty years. The rules and regulations currently in place for allocating cost obligations across all users of the grid (both the existing grid and expansions of this grid) are different for CMP than for Emera Maine, different for new load than for new generation and different for some new generation than for other new generation, even though the two generation projects might be essentially identical in all material respects. These rules and regulations were put in place in an era before distributed generation, when generators were large-scale facilities interconnected to the transmission components of the grid. In addition, they reflect compromises that may have been important decades ago but are simply no longer relevant today. Most important, they convey preferential access rights to use transmission and distribution grid capacities paid for by load to certain generators and not others through interconnection processes. The effect is to slow-down and even stall completely the development of new distributed generation at certain points on the grid.

There may be grid designs in the future that can enable Maine to meet its emission reduction objectives that do not require the ability to accommodate reverse power flows at the distribution level. What is clear, however, is that such a grid will be incapable of supporting an even modest buildout of distributed generation. Further, it will not support a network design structure in which point sources of load, distributed generation systems and battery storage are used in an optimal manner to meet grid requirements for the delivery of electricity, reliability and stability.

This last point is important. Introducing network-like designs into a broader geographic range of the distribution system not only enables multi-direction power flows, it permits loads to be served through multiple delivery paths, thus increasing reliability. Since the vast majority of power outages occur on specific distribution circuits, having a second or even third path for power to flow to loads can have a very significant impact on grid reliability.

Two factors impact the ability to design networked distribution systems capable of supporting multi-directional power flows. The first is the requirement that distributed generation can never be operated to serve load when such generation and load are "islanded" (that is, disconnected from the main transmission and distribution grid) unintentionally. Anti-islanding requirements are necessary to prevent distributed generation that is not intended or capable of serving load without the support of the electric grid from ever doing so, thereby leading to unsafe conditions that could cause major equipment damage and threaten health and safety. At issue is the achievement of a balancing of sometimes competing factors. On the one hand, anti-islanding requires all distributed generation sources (including the smallest rooftop facilities) to dispatch off at the exact instant the interconnection to the grid is lost. On the other hand, distributed generation can provide reliability and stability services to the broader grid if a problem is imminent, but only if these resources remain interconnected to the grid. In either case, however, there needs to be communication capabilities between the grid and each distributed generation resource that controls the on/off status of that resource. This can be expensive for small-scale distributed generation. It has not been a problem to date – and likely won't be an issue for a number of years, at least until power flows on distribution circuits reach negative levels at the substation due to the development of such distributed generation resources. Perhaps by then, widespread development of 5G wireless communication networks or other forms of communications may reduce communications costs and expand capabilities.

Assuming the technical issues related to anti-islanding can be addressed, the first area that requires policy attention relates to the interconnection of renewable generation projects to the electric grid. While some progress has been made in streamlining interconnection studies and standards, especially for smaller-scale projects, the interconnection process continues to present problems for project developers, especially in those instances in which the utility identifies necessary upstream grid improvements. Under current rules, any available capacity on the grid to support generator interconnection (capacity that has been paid for by ratepayers) is allocated at no charge to interconnecting generators on a first-come, first-served basis until such capacity is exhausted. At this point, the next generator in the interconnection queue must pay the full cost of all upstream improvements and upgrades to the grid that are required to interconnect its project. For small projects, the costs of this upgrade can amount to multiple times the cost of the project itself. Adding insult to injury, the next and succeeding generators in the queue able to utilize any spare capacity created as a result of the upgrades paid for by the previous generator in the queue. Not surprisingly, this policy acts as a serious drag on the development of renewable generation projects, and in some states such as Hawaii and California that are further ahead than Maine, has resulted in generation interconnection moratoria.

This current structure is intended to ensure that large-scale generators bear the interconnection costs for their location decisions to discourage uneconomic location decisions, the cost of which would otherwise be borne by ratepayers. This policy had merit for large-scale generation projects, such as nuclear plants and combined-cycle natural gas plants. However, today, the vast majority of interconnection requests are not from large nuclear, gas or coal plants, or even wind farms, but rather are from small-scale distributed generation resources, many of which are interconnected behind the customer's meter. The current interconnection process is simply not useful for these types of generation projects. The interconnection queue and the allocation of interconnection costs need fundamental change.

One proposal for addressing this issue is the so-called "clustering approach". This approach allows multiple generators to pool together to pay for grid related upgrades necessary for their interconnections. While there may be some cases involving a small number of very large-scale projects located in the same region of the electric grid where clustering could work, we are skeptical that this type of clustering will be effective in the majority of cases, especially those involving thousands of distributed solar PV installations and battery storage generation resources.

An alternative form of clustering is where the utility, acting on its own initiate, aggregates a number of small-scale distributed generation projects in its interconnection queue for simultaneous study. This new approach is being used across the New England Control Area. We are not sure of how this approach will work in those cases where the study indicates upgrade requirements are necessary for the transmission system. Open questions remain as to how the costs of such upgrades as well as the incremental interconnection capacity they create will be assigned in the first instance, and then reassigned when one or more of the distributed generation projects do not move forward to be built.

We believe that a better approach is one that facilitates the interconnection of small-scale projects, while preserving the price signaling feature of the current process for large utility-scale developments. This can be accomplished by allocating to electric loads in Maine the first $3 million of any upstream grid costs required to interconnect a generator. This compromise relieves distributed generation resources of the need to upgrade the immediately upstream substation as well as any feeders, reclosers, switches or other equipment located on the circuit serving the interconnecting generator, because these costs are almost always less than $3 million. Further, these are components of the distribution grid that will need to be upgraded to accommodate beneficial electrification – upgrades that would otherwise be paid for by load. In comparison, those large-scale generators such as utility-scale solar and off-shore wind, whose interconnection may impose significantly more costs on the utility in the form of new substation construction, new transformation capacity transmission line upgrades and other electronic equipment, will bear all costs in excess of the $3 million.

7.5 Addressing Regional Energy Balances

Figure 6-7 illustrates the fundamental mismatch between the growth in electricity use and the build-out of zero-emission, renewable generation to enable Maine to achieve a zero-carbon economy by 2050. Urban centers such as the Portland Region are not likely to be able to site generation within the region in enough quantity or of the appropriate type to offset peak load demands that will occur during the evening hours on the coldest days of the year. This means that most if not all this demand must be met through importing power from outside the region through new transmission lines.

Meeting this energy requirement will require major new 345 kV and 115 kV transmission lines as well as associated substations to meet N-1-1 conditions. The siting of these lines and substations will present serious challenges to the utility and to local governments. As anyone driving around the new Ravens Farm substation in Yarmouth will attest, high voltage substations are quite large and have much more of an industrial quality to them than most of the electric equipment found in towns in the region. In addition, the extensive new 115 kV loops in each of the southern and northern sections of the region to step-down power flows on these new 345 kV transmission lines for delivery downstream on the grid will present their own unique siting challenges. Further, once these lines are built, the entire system will become part of the bulk power system under which reliability standards will require meeting N-1-1 conditions.

Less obvious will be the fact that the higher load levels at various substations will likely require additional distribution feeders and, under a 25 MW maximum consequential loss of load requirement, may require redundancy of many components of the distribution system in the region, because each of these components will represent single points of failure that will expose loads in excess of 25 MW to consequential loss.

In the next chapter, we look at these new grid requirements and lay out one possible option for what the grid will need to look like to meet the increased peak load demands that come from beneficial electrification.

Chapter 8 - Portland Area

In this chapter, we consider the design of a transmission and subtransmission grid in the Portland Region that is capable of meeting reliably electricity demands post beneficial electrification. Our effort is necessarily limited. First, we are focusing on an electric region that is defined today in the context of the overall electric grid in Maine and current electricity usage levels. As electricity usage increases due to beneficial electrification, we may find that the existing electric regions are not optimal and need to be adjusted.

Second, we have not defined the source of generation except to allow for 1,000 MW of offshore wind landed at Wyman Station in Yarmouth and at the Tank Farm in South Portland. Since post 2050, the Wyman units in Yarmouth, the Calpine Westbrook gas plant and the Cape diesel units will all be shut down to meet the State's zero carbon requirements, we have assumed that some portion of the 5+ GW of offshore wind capacity in the Gulf of Maine will be interconnected to the New England electric grid in the region, as noted. We have further assumed that additional onshore wind and solar PV (in conjunction with battery storage) will be interconnected to the backbone system and, based on our proposed design of the grid in this region, capable of delivery into the region.

Third, GridSolar does not have the technical capabilities nor the electric system models to develop and test existing or potential electric grids. This is particularly important with respect to parallel electricity flows, voltage conditions and stability. It is also important in specifying grid components with ratings consistent with grid conditions during peak usage and peak power flows.

Our design looks only at system demands during periods of peak loads. We have designed the grid to ensure it can meet expected peak loads post beneficial electrification based on typical capacity ratings for key system components. Our effort here is a very high level exercise; further testing and refinement is necessary by those with the technical capacities to conduct this research and analysis. Nevertheless, we believe that our approach is highly instructive of the design features the grid must possess to meet future electricity demands and the costs of these features.

Further, and of direct relevance to the Portland Region, we believe that our modeling provides an important context for consideration of the reliability upgrades CMP has identified as required to meet reliability standards. These upgrades are based on current load levels. Therefore, they provide a very limited picture of what is required over the next 30 years if Maine is to meet its climate commitments.

We have divided this chapter into subsections that address each voltage level of the grid – 345 kV, 115 kV and 34.5 kV. At each level, we identify a grid design that has the capacity to meet peak loads post 2050. We use standard industry data and CMP cost estimates for other projects to estimate the cost of the incremental grid components that need to be developed. We estimate these costs to be roughly $2.5 billion in today's dollars. Of perhaps equal importance, we estimate that these components will require a land area that is roughly four-times the amount of land used by the 40 linear miles of I-295 and I-95 from the Freeport-Brunswick border to the Scarborough-Saco border.

8.1 The 345 kV Transmission Grid

8.1.1 The 345 kV Transmission Grid - 2020

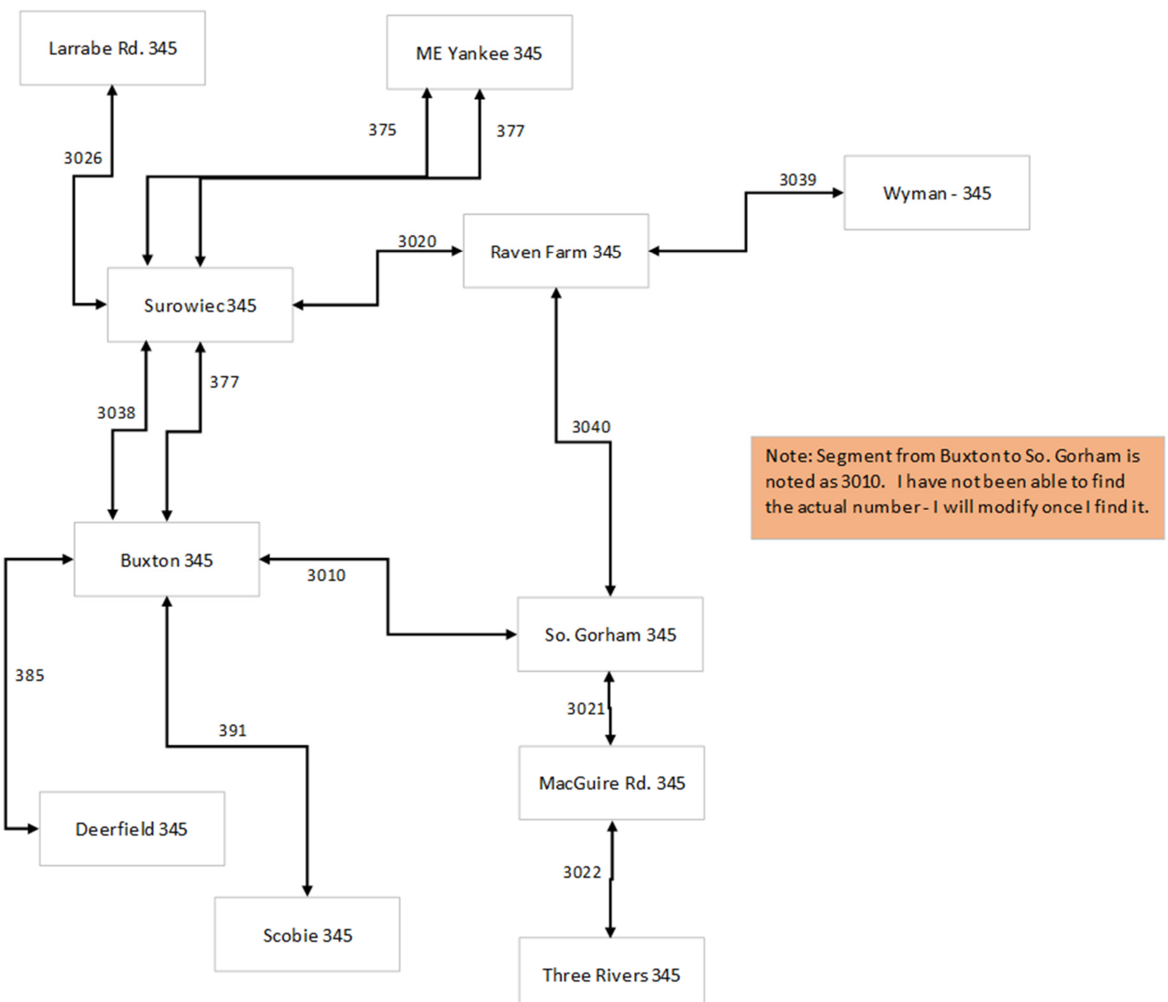
The existing (post-MPRP) 345 kV grid in Southern Maine is represented in Figure 8-1. All transmission segments are 345 kV. The current grid provides 3 separate 345 kV transmission paths for electricity to flow into/out of the Portland Region from New Hampshire (Deerfield, Scobie and Three Rivers) in the south to Maine Yankee/Larrabbe Road in the north. These transmission lines can deliver enough electricity to the Portland Region to meet current peak loads of 400 MW (give-or-take) under N-1-1 conditions (and assuming both Wyman 4 and Calpine-Westbrook are out of service). Electricity delivered to the Portland Region is stepped down to 115 kV at Surowiec (one 345/115 kV auto transformer) and South Gorham (two 345/115 kV autotransformers – the second one was added as part of the MPRP). The Raven Farm and Buxton substations do not currently offer step-down service. The Raven Farm substation was specifically built to handle an additional 345/115 kV autotransformer and a 115 kV feed to Cape Elizabeth. This part of the substation has not been built, pending the results of the Portland Area efforts. We expect the Buxton substation was built to enable a 345 kV line to extend to the South Gorham substation, thereby allowing service to that substation from the main north-south backbone as well as from Wyman 4 in Yarmouth.

We believe that the Portland Region's 345 kV grid meets all reliability standards at current load levels. It is the underlying 115 kV and 34.5 kV systems that CMP has identified as weak and where the issues lie and to which CMP has proposed its regional solution to address. The major components of this solution include:

1. A new 345/115 kV autotransformer at Raven Farm and a new 115 kV substation

2. A new 115 kV line from Raven Farm to Cape Elizabeth
3. 3 new 115/34.5 kV substations – North Yarmouth (off Surowiec) and East Deering and Anderson Rd (off the new line from Raven Farm to South Portland
4. Upgrades to the Pleasant Hill Rd. substation to accommodate a new 115 kV line from South Gorham

Figure 8-1 Electrical Representation of the 345 kV System - 2020



8.1.2 The 345 kV Transmission Grid – Post 2050

For purposes of simplifying and to define the requirements of the 345 kV grid in 2050, we assume that peak load in the Portland Region is around 1,000 MW in 2050. We further assume that two, 1,000 MW (+/-) Offshore Wind Farms (OWFs) interconnect in the Portland Region; that 1,000 MW of utility-scale solar PV facilities (greater than 100 MW) are developed in or adjacent to the Portland Region; and that the large-scale battery storage systems to meet seasonal cycling requirements are located outside the region where there is more space.

These assumptions create the following conditions – as shown in Figure 8-2:

New Generation:

- Two Offshore Wind Farms (OWF) have landing points for either AC or DC interties with Offshore Wind Farms – OWF A and OWF B – located in the Gulf of Maine. (We might anticipate as many as three more landing points in Maine – Maine Yankee, Bucksport and Rockland – for a total of 5 GW of OWF capacity.)
- An Aggregation and Delivery point for 1,000 MW of solar PV located in Cumberland and York Counties. While these large-scale solar PV systems (each in 100 MW or greater) may deliver power to the underlying 115 kV grid, they will need a separate path to the 345 kV grid, or they will overwhelm the conductor capacities of the 115 kV grid under maximum generation scenarios. Alternatively, the 1,000 MW of solar could come from far outside the region where land is more readily available. In this case, the existing grid might be adequate for importing the electricity – assuming there are no demands on the existing grid to move this electricity south through the region – which, given the sharp increases in electric loads by 2050, seems highly unlikely.

New 345 kV substations:

- OWF A – assumed to land at Wyman and displace a retired or infrequently run Wyman 4. No new substation is required for this landing point. (However, if the OWF is delivered to the mainland as dc power, a converter station will need to be located here.)
- OWF B – assumed to land at a new substation located at the tank farms in South Portland. (This could also include a dc converter station.)

- Solar PV – assumed to require a new substation located near or adjacent to South Gorham substation.

The 345 kV grid in the Portland Region must serve two functions. First, it must allow for the interconnection of the new large generation sources to the main 345 kV grid in the State. This is accomplished through generator leads – much the same way Wyman 4 has been and still is interconnected to South Gorham (via Raven Farm). The existing line 3039 from Wyman to Raven Farm serves this purpose for OWF A. New 345 kV lines – 3042 and 3050 serve this purpose for the solar PV and OWF B, respectively.

The second function is the ability to deliver electricity into the Portland Region under peak load (and minimum generation) conditions – a net of 1,000 MW under our assumptions above – while meeting N-1-1 conditions. This requires the development of a pair of 345 kV loops within the Portland Region to enable the grid to deliver 1,000 MW of electricity under N-1-1 conditions – where any 2 segments are off-line simultaneously.

New 345 kV lines:

One design for the loops is illustrated in the Figure 8-2. This design requires the following new 345 kV line segments, in addition to the "generator leads" noted above.

- 3038 – Wyman Station to Raven Farm – a parallel path to the existing line 3039.
- 3041 and 3042 – Raven Farm to Solar PV to South Gorham – a parallel path to line 3040 from Raven Farm to South Gorham.
- 3050 – Generator lead from South Portland to South Gorham
- 3052 and 3042 – South Portland to Solar PV to South Gorham – a parallel path to line 3050
- 3060 and 3061 – Two parallel paths completing the loop from South Portland to Wyman, both of which are likely to be undersea cables, given land constraints.
- 3043 – Surowiec to Solar PV to provide a fourth 345 kV entry point to deliver electricity into the Portland Region from the main 345 kV grid. (This could also come over from the Buxton 345 substation.)

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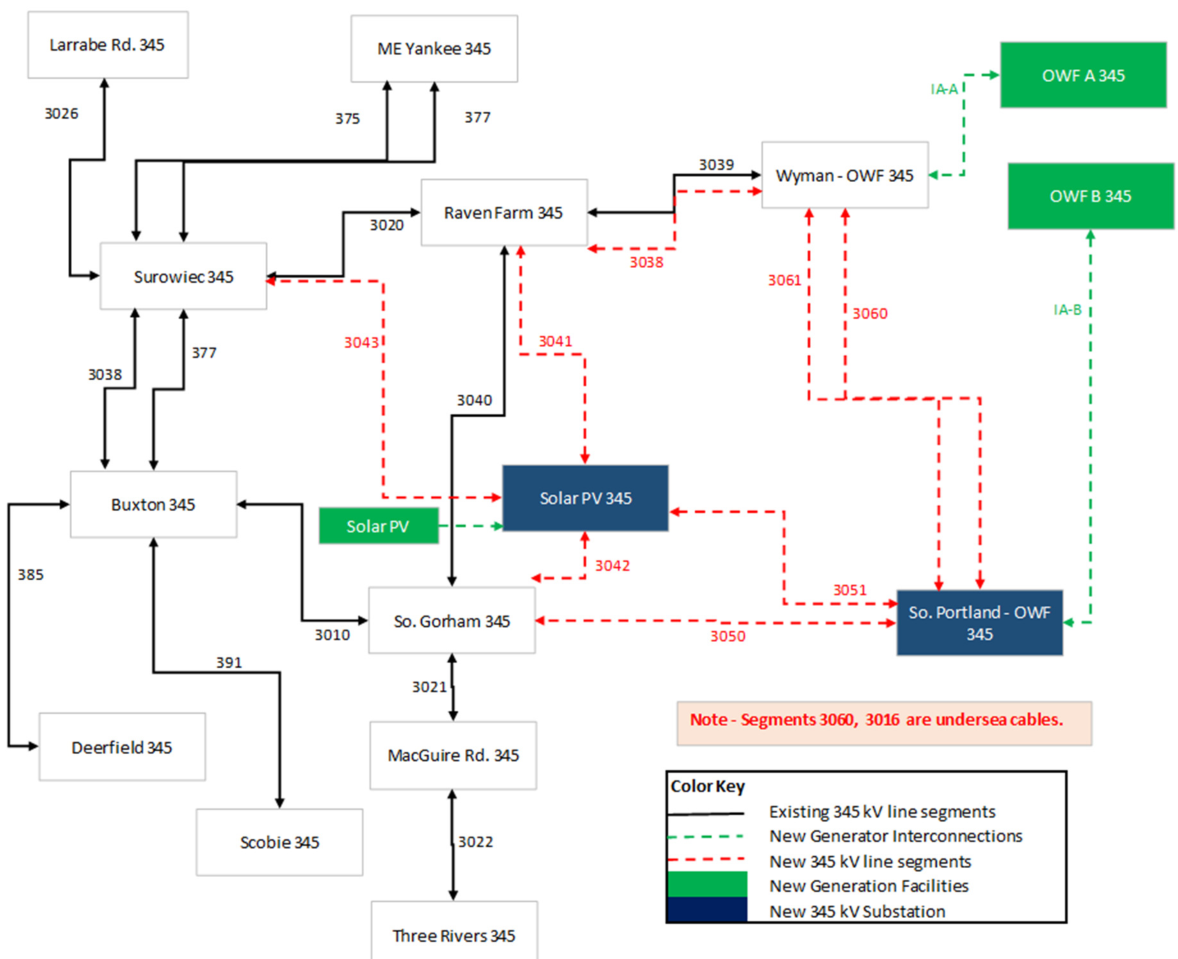
This configuration would require new 345/115 kV autotransformers at Raven Farms, South Portland and Solar PV, based on our suggested design of the 115 kV grid discussed in the Section 8.2 below.

This new 345 kV loop accomplishes the following objectives:

1. It enables generation to flow from the two OWFs and from the solar PV (through Solar PV 345 substation) under all N-1-1 conditions.
2. It enables 1,000 MW of electricity to flow uninterrupted around the loop under all N-1-1 conditions.
3. It enables 1,000 MW of electricity to flow from the main 345 kV grid (assuming there is zero wind and solar generation) under all N-1-1 conditions. There are 4 paths to the 345 kV Portland Loop – three existing ones - lines 3020, 3010 and 3021, plus a new one - 3043.

Figure 8-2 Electrical Representation of the 345 kV System - 2050



8.1.3 Estimated Costs of the 345 kV Grid Additions

The estimated costs of the additions and modifications to the 345 kV grid to meet peak load conditions in the Portland Region at N-1-1 reliability levels are just under $1 billion (in 2020 dollars) as shown in Table 8-1. We have developed these cost estimates from those prepared by CMP to support the development of the Maine Power Reliability Program (MPRP). The MPRP costs used were from the latest of such filings made in August 2009. Table 1 identifies each of the MPRP substations we used as a model for each of the new substations and the estimated costs for these in 2009 – e.g., we used the new Coopers Mills substation as the reference model for the proposed new South Portland substation. The 2009 cost estimates were inflated by cost inflation to 2020 using an average annual inflation rate of 3%. We made no adjustments to reflect potential land acquisition and construction cost differentials in the greater Portland area compared to the model areas.

The lower portion of Table 8-1 identifies various 345 kV line segments that were proposed for construction under the MPRP. Each segment shows its length and estimated costs. We used these to calculate an average cost per mile. The average cost per mile across these 7 segments and 182 miles was just under $2.5 million. We increased this to $4.652 million per mile to adjust for what we would expect to be higher construction costs within the Portland Region. We compared the costs of 115 kV line segments to be constructed north of Lewiston to those to be constructed in the Portland Region. When the averages of these two sets is compared in 2020 dollars using a 3% average inflation factor, the Portland Region costs are almost double those in the rural area north of Lewiston. This adjustment is shown in Table 2.

Finally, since the MPRP did not contain any undersea cable components, we made the assumption that the 2009 cost of constructing 345 kV line segments undersea would have been two-times the cost per mile of average land-based systems. This comes to a little over $9 million a mile, which is in the range of HVDC undersea cable systems. (We note also that a relatively short 1.2 mile underground segment of 115 kV cable in downtown Lewiston was estimated by CMP to cost about $7 million in 2009.)

Table 8-1 Estimated Costs (2020$) of 345 kV Grid Additions

345 kV Substations	Costs - 2008 (million$)		Costs - 2020 (million$)
Wyman OWF			
Model - Suroweic MPRP		$32.156	$44.51
Substation Upgrade	$30.144		
Line Terminations	$1.006		
South Portland OWF			
Model - Coopers Mills MPRP		$124.252	$171.99
Substation	$119.856		
Line Terminations	$4.396		
Solar PV			
Model - Larrabbe Road MPRP			
Substation	$71.357	$73.406	$101.61
Line Terminations	$2.049		
345 kV Segments - Land-Based	**Miles**		
3050 - S. Portland to S. Gorham	10.0	$46.516	$64.39
3051 - S. Portland to Solar PV	10.0	$46.516	$64.39
3042 - S. Gorham to Solar PV	1.0	$4.652	$6.44
3043 - Suroweic to Solar PV	23.0	$106.986	$148.09
3041 - Raven Farms to Solar PV	16.0	$74.425	$103.02
3038 - Wyman to Raven Farm	6.0	$27.909	$38.63
345 kV Segments - Undersea			
3060 - Wyman to S. Portland	9.0	$83.728	$115.90
3061 - Wyman to S. Portland	9.0	$83.728	$115.90
Total Capital Investment - 2020$	84.0		**$974.88**

MPRP		**Miles**	**Cost (million$)**	**Cost/Mile (million$)**
3020 - Raven Farm to Suroweic		10.0	$29.400	$2.940
3021 - S. Gorham to Maguire		21.0	$50.200	$2.390
3022 - Maguire to Three Rivers		19.2	$46.800	$2.438
3023 - Orrington to Albion		59.0	$112.485	$1.907
3024 - Albion to Coopers Mills		21.0	$54.026	$2.573
3025 - Larrabbe to Coopers Mills		17.0	$32.935	$1.937
3026 - Larrabbe top Suroweic		34.4	$121.350	$3.528
		181.6	$447.196	$2.463
Adjust Portland Area Costs				$4.652
Undersea 345 kV Costs Per Mile				$9.303
Factor Increase	2			
Cost Adjustment Factor to 2020				138.4%
Est. Avg. Annual Inflation 2009 - 2020	%	3.0%		

Source: MPRP Cost Estimate of PPA by Component and Region
CMP Filing in Docket No. 2008-00255 - Attachment 3
8-Aug-09

Table 8-2 Estimate of Portland Region Cost Differential

2009 to 2018 Inflation Factor at 3%	130.5%			
2018 to 2020 Inflation Factor at 3%	106.1%			
	Miles	**Cost**	**Cost/Mile**	**2020$**
MPRP - 2009				
251 - Larrabbe to Livermore Falls	24.1	$33.625	$1.395	$1.820
255 - Larrabbe to Middle St (Lewiston)	4.2	$6.048	$1.440	$1.879
Average				$1.850
Portland Region - 2018				
So. Gorham to Pleasant Hill	9	$25.800	$2.867	$3.041
Raven Farm to East Deering	10	$37.200	$3.720	$3.947
Average				$3.494
Portland Region Cost Adjustment Factor				**189%**

8.2 The 115 kV Transmission Grid

8.2.1 The 115 kV Grid – Post 2050

The existing 115 kV grid in the Portland Region consists of 12 substations fed from the 345 kV system at Surowiec and South Gorham. According to CMP's 2018 Needs Assessment, this grid is inadequate to meet current 90/10 peak load levels of 400 MW under N-1-1 conditions. It is woefully inadequate at the much higher 1,100-plus MW peak load levels by 2050.

The 115 kV grid for the Portland Region by 2050 will be part of the Bulk Power System. Accordingly, it must meet the following conditions:

1. It must satisfy N-1-1 conditions.
2. It must be capable of delivering electricity to all sub-regions at the load requirements for these regions in 2050.
3. It cannot be designed to place loads on the conductors that exceed ratings – which we have assumed to be 200 MW, based on winter ratings, since this peak occurs during the winter.

One design that we believe meets these standards is represented in Figure 8-3. This design is based on the delineation of electric sub-regions, each one served by a major 115 kV substation. Since peak loads are 1,100 MW, the seven sub-regions can be defined in which each sub-region has a peak load of less than 200 MW.[42] The seven sub-regions are – Raven Farm, Surowiec, Central, S.

[42] We have allowed the South Portland substation to exceed this load level by a small amount.

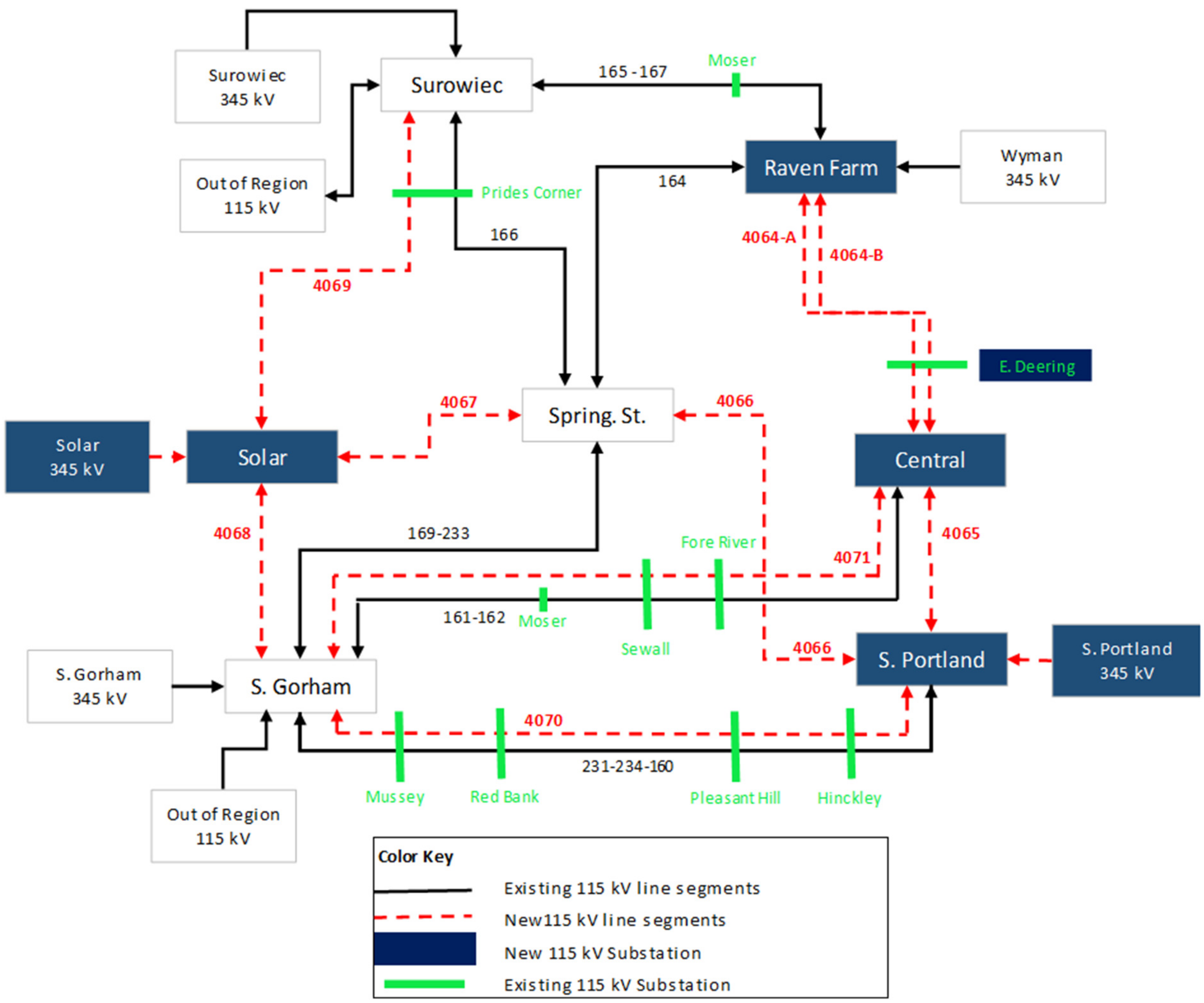
Portland, S. Gorham, Solar and Spring St. Estimated 2050 peak loads (measured at the current substations – see Chapter 6) are shown in Table 8-3 – along with their allocations to one of the seven sub-regions.

Table 8-3 Load Assigned to Sub-Regions

Existing Substations	Assigned Sub-Region	Peak Load (MW)
Cape Elizabeth	S. Portland	50.92
Rigby	S. Portland	37.81
Pleasant Hill	S. Portland	69.22
Hinckley Pond	S. Portland	49.86
Subtotal - S. Portland		**207.81**
Red Brook	S. Gorham	9.08
Scarborough	S. Gorham	29.89
Dunston	S. Gorham	28.87
Western Avenue	S. Gorham	26.65
Mussey	S. Gorham	10.63
Westbrook	S. Gorham	34.64
Subtotal - S. Gorham		**139.76**
Falmouth	Spring St.	32.58
Spring St. 115 kV	Spring St.	11.05
Spring St. 34.5 kV	Spring St.	34.58
Bishop	Spring St.	69.20
Lambert	Spring St.	48.03
Subtotal - Spring St.		**195.44**
Swett	Solar	42.65
Prides Corner	Solar	49.83
Brighton	Solar	25.57
Mosher	Solar	32.26
Subtotal - Solar		**150.31**
Forest Avenue	Central	22.85
Union	Central	61.91
Sewall	Central	52.13
Fore River	Central	48.36
Subtotal - Central		**185.25**
Gray	Suroweic	56.01
Freeport	Suroweic	52.60
Subtotal - Suroweic		**108.61**
East Deering	Raven	38.90
Elm St 115 kV	Raven	106.42
Wyman	Raven	18.82
Subtotal - Raven Farm		**164.14**
TOTAL - PORTLAND REGION		**1151.32**

Figure 8-3 shows each of the seven 115 kV substations that serve each of the sub-regions. This configuration incorporates the existing substations at Surowiec, S. Gorham and Spring St. and adds four new substations – Raven Farm, Solar, Central and S. Portland.[43] Three of these are located adjacent to 345 kV substations. The exception is Central. This substation is located in Portland center to serve loads in the central parts of Portland.

Figure 8-3 Electrical Representation of the 115 kV Grid – Post 2050



By design, each of the substations is served by a minimum of three 115 kV lines that extend back to 345 kV substations. This allows for each sub-region's peak loads to be served under N-1-1

[43] The E. Deering substation is shown as a new 115 kV substation; however, its design and scope of services provided is more akin to the other substations shown in green than to these 115 kV substations.

conditions. In addition, each of the other 115 kV stations (shown in green) are capable of being served by two different upstream substations without exceeding the 200 MW threshold. The exception is E. Deering. If service is lost from Raven Farm and E. Deering is forced to be served from Central, the total loads at Central would exceed 200 MW. This has been addressed by adding a second feed from Raven Farm to Central. While this feed has to go only as far as the E. Deering substation to meet this requirement, we have extended it all the way to Central to provide additional redundancy into downtown Portland.

As with the 345 kV system, we have estimated the costs for the new substation facilities using model substation costs from the MPRP, inflated to 2020. The results are shown in Table 4. Costs for the 115 kV lines are estimated using costs per mile values from the 2018 Portland Area Study that have been similarly inflated to 2020. In addition, we added 1 mile of undersea cabling to connect the Central and S. Portland substations. The total estimated cost of the new facilities is $520 million.

Table 8-4 Estimated Costs (2020%) for 115 kV Grid Additions

115 kV Substations	**Costs - 2009 (million$)**		**Costs - 2020 (million$)**
Raven Farms			
Model - Raven Farms MPRP		$44.700	$61.88
Substation Upgrade	$38.470		
Line Terminations	$3.115		
South Portland			
Model - Raven Farm MPRP		$41.585	$57.56
Substation	$38.470		
Line Terminations	$3.115		
Solar PV			
Model - S. Gorham MPRP			
Substation	$28.872	$29.851	$41.32
Line Terminations	$0.979		
Central			
Model - Raven Farm MPRP			
Substation	$38.470	$41.585	$57.56
Line Terminations	$3.115		
115 kV Segments - Land-Based	**Miles**		
4064-A - Raven Farms to Central	12.0		$41.93
4064-B - Raven Farms to Central	12.0		$41.93
4066 - S. Portland to Spring St.	10.0		$34.94
4067 - Solar to Spring St.	3.0		$10.48
4068 - Solar to S. Gorham	3.0		$10.48
4069 - Solar to Suroweic	23.0		$80.36
4070 - S. Gorham to S. Portland	10.0		$34.94
4071 - S. Gorham to Central	11.0		$38.43
115 kV Segments - Undersea			
4065 - Central to S. Portland	1.0		$8.42
Total Capital Investment - 2020$	85.0		**$520.23**

8.3 The 34.5 kV Subtransmission System

The primary impact beneficial electrification has on the 115 kV and 345 kV transmission grids is to increase the number of substations and lines within the Portland Region. Because the larger transmission grid must satisfy N-1-1 reliability conditions, that grid remains loop fed and allows bidirectional electricity flows. The overall design and general structure of the grid itself is largely unchanged. This is not the case with the underlying 34.5 kV grid.

There are two factors that have a direct impact on the design of the 34.5 kV system post beneficial electrification. The first factor is the 25 MW consequential loss of load limitation embedded in Maine transmission and distribution planning guidelines. The second factor is the significant increase in electricity use post beneficial electrification, what we will refer to as "electricity use density". Taken together, these two factors require a redesign on the 34.5 kV system.

Consider the second factor. Currently, a typical Maine residential housing unit uses roughly 5,000 kWh per year, drives approximately 15,000 miles a year and uses the thermal equivalent of 750 gallons of heating oil for space heating. Post beneficial electrification, assuming that housing unit converts to EVs and air-source heat pumps, its electricity use will increase by approximately 4,000 kWh to power its EVs (assuming most of its charging of the EVs is done at the housing unit) plus about 10,000 kWh to replace its fossil fuel burner system. Total electricity use at the housing unit will increase from 5,000 kWh to roughly 20,000 kWh – a four-fold increase. The electricity use density at that housing unit's geospatial location has quadrupled.

This increase in electricity use density is evident across all 34.5 kV substations in the region as shown in Table 6-4. Consider the case of Freeport. In 2020, peak loads through the two transformer banks at the substation were just over 15 MVA. By 2050, they are estimated to be more than 50 MVA. This means that the current situation, where the Freeport substation is served radially out of Elm Street (See Figure 2-3), is not acceptable. By 2050, the loss of Section 104 would result in a consequent loss of load well in excess of 25 MW, not only during the peak hour, but during most hours of the year.[44]

A different but equally concerning situation arises with respect to 34.5 kV substations that are fed bidirectionally in series from two upstream 115 kV substations. Today, this design provides improved reliability, since it enables all substations along this path to survive the failure of a section

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[44] The same conditions apply to the Gray, Care Elizabeth, E. Deering, Rigby and Swett Road substations, as well as Hinckley Pond at the 115/12.5 kV substation.

of 34.5 kV line or an upstream transformer at one of the 115/34.5 kV substations.[45] A case in point is line 180 and its offshoot to E. Deering, line 180A. This line allows the Falmouth, E. Deering and Lambert Street substations to be fed from either Prides Corner or Elm Street. Peak loads on this line are roughly 9 MW, 10 MW and 12 MW, respectively, at 90/10 load levels, for a total of 31 MW. Assuming the transformers at each end of line 180 have enough capacity and the 34.5 kV conductors are appropriately sized along the entire route of 180, this design satisfies the 25 MW loss of load criteria. However, at estimated 2050 peak load levels of 32 MW, 38 MW and 47 MW, the current design cannot carry the loads. The total load of almost 120 MW far exceeds the capacity of any 34.5 kV conductors. The problem is that increased electricity use density makes it much more challenging to design a 34.5 kV that allows for service from different upstream 115 kV substations. Table 6-4 shows that, by 2050, no two 34.5 kV substations can be served simultaneously from two different upstream 115 kV substations along a single 34.5 kV path.

The increased electricity use density that results from beneficial electrification means that the two forms of service currently embedded in CMP's existing 34.5 kV grid in the Portland Region – radial and single-path bidirectional service – will not meet requirements. Instead, a variant of either of the two options shown in Figure 8-4 must be used.

Figure 8-4 presents two options – a Parallel Path option and a Loop Feed option – for loads in Gray and Freeport that have been assigned to take service from the Surowiec 115 kV substation. By 2050, peak loads at Gray and Freeport are estimated to be each a bit over 50 MW. We made the assumption that serving these loads in each geographic subregion will be best accomplished through two 34.5 kV substations of between 25 and 30 MW each.

The Parallel Path option, shown in the upper chart in Figure 8-4, enables each of the four 34.5 kV substations to be served from either the Surowiec or Raven Farm 115 kV substations. However, given the load requirements at each substation, this can only be accomplished by developing four parallel 34.5 kV paths – one for each substation. The second option, noted as the Loop Feed option in Figure 8-4, provides two 34.5 kV points of interconnection to a single 115 kV substation using two 34.5 kV lines. The number of interconnections within the 115 kV and 34.5 kV substations are the same for each option. The difference lies in the 34.5 kV line segments connecting each 34.5 kV substation to either one or two 115 kV substation. The preferred option

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[45] The design can also provide a parallel path enabling electricity to flow to serve load in the event of an outage of an element of the 115 kV system, assuming grid component ratings are not exceeded.

from a cost perspective, therefore, depends on the relative distances between 115 substations compared to the relative distances of the substations from the single 115 kV substation.

Figure 8-4 Two Options for 34.5 kV System Design Post 2050

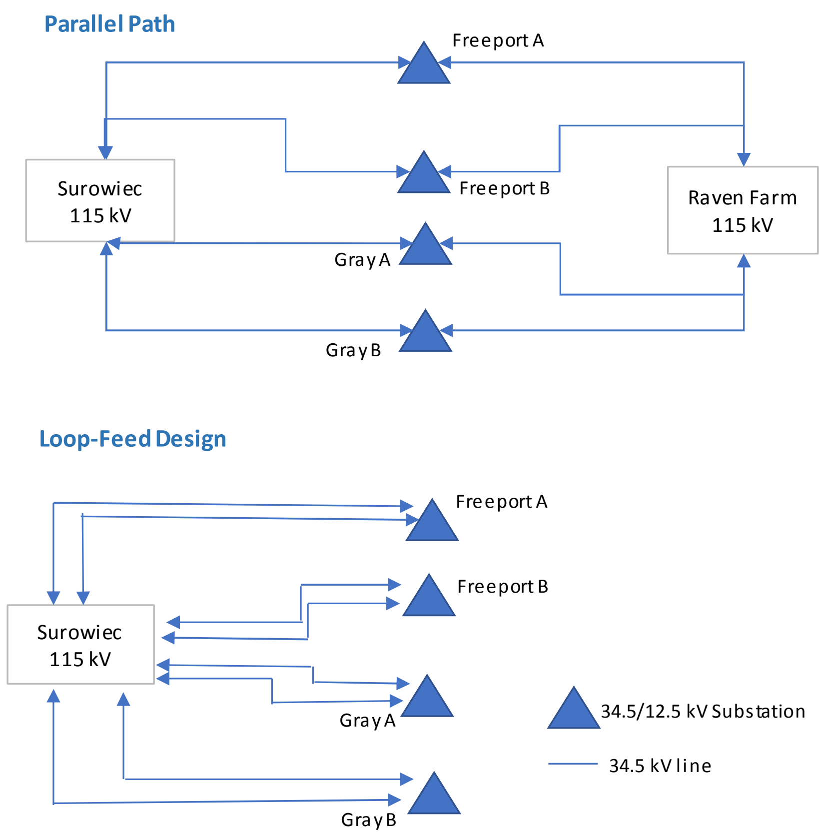

Table 8-5 provides an estimate of the costs (in 2020$) required to develop the 34.5 kV subtransmission system to meet the load requirements of full beneficial electrification in the Portland Region. The top part of the table shows the calculation for the 25 new 115kV/34.5 kV substations that will need to be built, assuming each substation serves no more than about 25 MW of peak load. To estimate the costs, we have used an average of the three new 115 kV/34.5 kV substations identified in CMP's 2018 Portland Region study, escalated to 2020 dollars. The total cost for these substations is approximately $557 million.

The bottom part of the table shows the derivation of the costs for the additional 34.5 kV lines, assuming that the average distance between each substation and its assigned 115 kV substation is 3 miles and further assuming that each of the 25 existing 115/34.5 kV substations requires only 1 new line while each new 115 kV/34.5 kV substation requires 2 new lines. Using the two examples from the 2018 CMP Study shown in the table and escalating their costs to 2020, we calculate that total costs of new 34.5 kV lines to be $492 million. The total costs of the 34.5 kV system are a little over $1 billion.

Table 8-5 Estimated Costs – 34.5 kV System Post 2050

		Assignment of 34.5 kV Substations			
115 kV Substations		**2020**	**2050**		
S. Portland		4	10		
S. Gorham		5	8		
Spring Street		5	10		
Solar		4	7		
Contral		4	8		
Elm Street		3	7		
Total		25	50		
New 115 kV/34.5 kV Substations			25		
Costs - New 34.5 kV Substations					
CMP 2018 Report		**2018**	**2020**		
E. Deering	million$	$20.00	$21.22		
Anderson St.	million$	$18.00	$19.10		
N. Yarmouth	million$	$25.00	$26.52		
Average	million$		$22.28		
Cost of New 115 kV/34.5 kV Substations	million$		**$556.97**		
34.5 kV Lines					
Average Distance of 34.5 kV Substation	miles		3		
Total Number of Lines					
Existing 34.5 kV Substations	No.		25		
New 34.5 kV Substations	No.		50		
Total	miles		225		
				Cost/Mile (million$)	
Costs - New 34.5 kV Lines					
CMP 2018 Report		**Miles**	**Cost**	**2018**	**2020**
N. Yarmouth - Freeport		11	$22.80	$2.07	$2.20
N. Yarmouth - Gray		4	$8.20	$2.05	$2.17
Average					$2.19
Cost of New 34.5 kV Lines	million$		**$492.05**		
Cost of 34.5 kV System	million$		**$1,049.03**		

8.4 Summary

The costs of the transmission and subtransmission upgrades are summarized in Table 8-6. We estimate the total system costs for the Portland Region to be about $2.5 billion in today's dollars.

This amount does <u>not</u> include costs related to the expansion of the distribution grid and, where feasible, the conversion of that grid from a primarily radial design to a network design capable of enabling two-way flows of electricity and providing increased reliability.

Table 8-6 Summary – Estimated Cost of Transmission/Subtransmission Upgrades - 2050

Estimated Transmission/Subtransmission Costs	No.	Miles	Cost (millions$)
345 kV System			
New 345 kV Substations	3		$318.12
345 kV Line - Overhead		66	$424.96
345 kV line - Undersea		18	$231.80
Subtotal			$974.88
115 kV System			
New 115 kV Substations	4		$218.32
345 kV Line - Overhead		84	$293.49
345 kV line - Undersea		1	$8.42
Subtotal			$520.23
34.5 kV System			
New 115 kV/34.5 kV Substations	25		$556.97
34.5 kV Line - Overhead		225	$492.05
34.5 kV line - Undersea		0	$0.00
Subtotal			$1,049.03
Total Transmission/Subtransmission			**$2,544.13**

We have looked at what the land requirements for the required transmission and subtransmission system components might be based on the footprints of the various components. The results are shown in Table 8-7. We have included only the transmission line and substation components of the grid; as with the cost calculations, we have not included distribution circuits. For transmission lines, we have used representative right-of-way corridor widths and estimated segment lengths based on the new proposed design of the grid post 2050. Using these parameters, we calculated the footprint (in acres) of each line segment for each voltage.

We have done the same calculation for substations. Here, we have used the Surowiec Substation as a model for the 345 kV category, the Spring Street Substation as a model for the 115 kV category and an approximation of the size of 115 kV/34.5 kV substations. In addition, we have added set-backs or buffers for each class of substation as shown in the table.

Based on these parameters, we calculate the amount of acreage required to be 3,764 acres. To put this in perspective, we have compared this to the acreage used by the Interstates 295/95 from Freeport to the Saco border, a distance of roughly 40 miles. The footprint of this linear ribbon running the length of the Portland Region is approximately 970 acres. The land requirements for the grid build-out are almost four times those of the Interstate corridor – that is, building out the grid will require the equivalent of four new Interstate 295/95 corridors running from Freeport to the Saco border. This is the land-use equivalent of Figure 6-6, which shows graphically just how different the flows on the electric grid will be in a zero-carbon economy in 2050.

Table 8-7 Land-Use Consequences of Electric Grid Build-Out

		Width	Length	Area
Transmission Lines		**(ft.)**	**(miles)**	**(acres)**
345 kV Lines		150	66	1,200
115 kV Lines		100	84	1,018
34.5 kV Lines		50	225	1,364
Subtotal				3,582
		Width	**Length**	**Area**
	No.	**(ft.)**	**(ft.)**	**(acres)**
Substations				
345 kV Lines	3	1,200	1,700	140
115 kV Lines	4	450	450	19
115 kV/34.5 kV	25	200	200	23
Subtotal				182
Total Land Area				3,764

Notes:

Buffer Factors - Set Backs for Substations:

345 kV	Feet	200
115 kV	Feet	150
34.5 kV	Feet	100

Interstate 295/95	(ft.)	(miles)	(acres)
Freeport to Scarborough	200	40	970

These land-use requirements can be mitigated to a degree by undergrounding transmission lines. However, this comes at a significant expense, as much as a doubling of the respective per mile costs. Alternatively, the corridors could be narrowed considerably and located above or alongside other rights-of-way such as highways, railroad lines, and streets as is done in other cities across the country, where, presumably, visual impacts and risks to health and safety are evaluated differently.

In any case, the impacts on land-use in the Portland Region that will result from the build-out of the transmission and distribution grid necessary to achieve a zero-carbon economy by 2050 will be substantial – possibly on a par with those related to the building of new roads to accommodate the explosion of cars and trucks over the latter half of the 20th century. It is not too early to begin to plan for grid needs over the 30-year planning horizon between now and 2050. One very important aspect of this effort should be the setting aside by municipal governments in the region of land corridors to accommodate future transmission lines and the establishment of zoning ordinances to permit their development. In addition, we believe it is prudent for utilities to look acquire rights, title or interest in land in the region that can be put to use over the next thirty years in support of transmission grid expansions.

8.5 Concluding Thoughts

By any measure, the region's electric grid will need to become significantly larger and will require significant investments over the next 30 years. The grid design we lay out in this chapter represents one of countless designs that can meet 2050 electric loads and accommodate decarbonization of the grid. The actual design is of far less importance today than is the recognition that the region's electric grid in 2050 will look very different – of this we can be certain. And yet, decisions will have to be made about how to incrementally expand the grid, how to replace and renew grid components, how to accommodate large numbers of distributed generation systems and how to meet increasingly stringent standards for reliability and resiliency. Should these decisions be made based on current grid conditions or should they be made so as to be consistent with and support longer-term policy objectives, and if the latter, what is the appropriate planning horizon?

Addressing this question is made more difficult because of the geospatial rigidity of transmission and distribution plant – once in place, it is not easily moved, and because of its "lumpiness" – it is built out in relatively large increments rather than small units. These characteristics make such investments susceptible to being rendered uneconomic as a result of unpredicted futures. As with all capital intensive, fixed location infrastructure, building out the electric grid must be done in a balanced way with one-eye firmly focused on the longer-term requirements of electrification as a means of decarbonizing the economy and the other on the near-term requirements of reliability and resiliency.

In the prior chapter, we discussed some of the guiding principles that we believe should guide electric grid planning. We turn now to illustrating how we believe these principles may be put to work in the context of CMP's proposed transmission investments in the Portland Region. Below, we consider the major components of CMP's proposed Transmission Solution 1 in its Portland Area Study to determine whether and how they may fit in to the longer-term needs of the region and the designs set forth above.

1. Raven Farm 345 kV/115 kV Substation – This is a key component in the 2050 design. The longer-term design includes one additional 115 kV feed. As CMP designs this new substation, we recommend that its design allow for this additional feed to be constructed at a later date.
2. North Yarmouth Substation – This substation is not included in the 2050 design. CMP is proposing to loop feed Gray, Freeport and North Yarmouth out of both Raven Farm and Surowiec. While this configuration works at current load levels and provides improved reliability in this sub-region, we do not believe it will work as conversions to electrification occur. Instead, our 2050 design opts to loop-feed a total of four 34.5 kV substations in Gray and Freeport out of the Surowiec 115 kV substation. If CMP believes the North Yarmouth Substation to be a component of the longer-term grid design for the region, CMP should be required to make this demonstration to support its position.
3. E. Deering 115 kV/34.5 kV Substation – This is included in the 2050 design. The longer-term design we have laid out includes a parallel, second 115 kV feeder from Raven Farm to Central. We recommend that the design of this new substation includes allowance for this additional feeder.
4. Sections 262, 263N and 263S – This 115 kV line connecting Raven Farm to Cape, through new E. Deering and Anderson St. substations is included in our proposed 2050 design. A second parallel 115 kV line is also included in the 2050 design, as noted in item 3. Securing a right-of-way for CMP's proposed new overhead 115 kV line will be difficult in this part of the region. Securing a second right-of-way in 20 years will be even more difficult. We recommend that any new right-of-way that is acquired be capable of supporting two parallel 115 kV lines on separate towers – or a minimum allow for the undergrounding of a second line in the future.
5. Anderson Street Substation – While this substation is not included in our 2050 design, a more robust and larger 115 kV substation – "Central" – is included in that design. We are skeptical that the Anderson Street location is adequate to meet the longer-term needs of the region, and if

constructed, could obsolete well before the end of its useful life. Further, we are concerned that our proposed Central Substation could be a difficult substation to physically locate in Portland on the path of the parallel 115 kV feeds between Raven Farm and the new 115 kV substation at S. Portland at the Tank Farm. Given the building density in this region and the lack of open-space, CMP should look to acquire lands today that will allow it to build a major new 115 kV substation to meet future electricity requirements. This may require a new design for substations – one that is more suitable for high density urban areas, which, in turn, may require modifications to Portland's zoning ordinances and building codes.

6. Pleasant Hill Substation upgrade – This is included in our 2050 design to accommodate parallel 115 kV feeds between the S. Gorham and S. Portland 115 kV substations. We expect this expanded substation to be a major component of the 2050 grid and recommend that CMP designs its upgrade to be able to accommodate additional 34.5 kV transformers and feeders.
7. New 115 kV line from S. Gorham to Pleasant Hill – This is included in our 2050 design. Our design extends this line (4070 in Figure 8-3) beyond Pleasant Hill to S. Portland.

In addition to the above items, we recommend that CMP begins the process of acquiring land for future 34.5 kV substations in the region, consistent with our discussion about loop feeding these from larger 115/34.5 kV substations. The amount of land necessary is not large and, since this land can be sold if not used for this purpose at a later date, the investment is not at risk of being stranded. The recent experiences of Emera Maine in Bar Harbor may be telling in regard to how difficult it will be to locate distributed substations in the future. Having these locations established well in advance and reflected on town planning maps could make it less difficult to secure permits for their development in the future.