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Integrated Resource Plan for Portland General Electric (PGE)

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1. Introduction

1.1 Background

An Integrated Resource Plan (IRP) is a roadmap that power utilities use to plan how they will meet the energy demand for their customers in the most reliable and least-cost way. This is done in alignment with state and federal policy requirements. State governments commonly require utilities to file their IRP with their state public utility commissions. The public utility commission usually requires the utility to submit regular IRP updates every two to three years. Approving an IRP is a huge stakeholder driven process that can span several months or an entire year(s). The final IRP is a comprehensive strategic document that drives the utility actions for the next 10-15 years or more (as defined in the IRP).

There are several reasons why an IRP proposal is an integral part of the utility's resource planning process- (1) energy investments are capital intensive and both the public and the government is impacted by such high cost-centric projects; (2) most power plants last for a very long time and can range between 20 to 100 years before they retire. Such massive long-term investments are necessary to be well understood before they go online; (3) IRPs go through several rounds of public hearings and state utility commission proceedings before plans and strategies in the IRP get approved. A public review process of the IRP provides an avenue for transparency and communication with the stakeholders. Also, the utility can showcase its plan/investments in clean energy technology and environmental measures. (4) it provides an opportunity for vendors and potential partners, e.g. independent power producers, project developers etc. to get access to the utility's future projects and prepare for bids or find other ways of getting involved with the utility.

To ensure that the utility's electricity is least cost, least risk, safe and reliable, there are several factors that get considered in the IRP, for example- (1) the changing energy demand over the next several years; (2) timeline of existing generation assets and addition of new generation (thermal, hydroelectric, nuclear, renewable etc.); (2) cost-effectiveness of mixed generation portfolios; (3) state and federal regulations and policies- such as carbon reduction goals, renewable portfolio standards (RPS) etc.; (4) energy efficiency measures; (5) electrification of previously gas-operated systems; (6) electrification of transportation; (7) environmental measures amongst many other factors.

This master's project is an IRP for the electric utility Portland General Electric (PGE) and attempts to explore the questions and scenarios that are not currently considered in the utility's official IRP and go beyond Oregon's RPS and emissions goals. Such questions and scenarios revolve around how the utility can reach zero emissions by 2050. The modeling is performed using publicly available data from the U.S. Energy Information Administration (EIA), U.S. Federal Energy Regulatory Commission (FERC), National Renewable Energy Laboratory (NREL) and modeling tools and resources provided or created during the project. We chart a 30-year horizon from 2020-2050 and consider Oregon's key pieces of legislation to outline and propose a recommendation for how PGE can reliably serve their customers while reaching zero emissions by 2050.

Our modeling adheres to the key clean energy policies in the state and is in alignment with the Oregon Public Utility commission (OPUC) regulations. The OPUC is the central regulatory body in the state that regulates the rates and services offered by all power utilities, telecommunication companies, and water companies to ensure safe and reliable services at reasonable rates. Here are some of the key policies we considered:

2016 Oregon Clean Electricity, Coal Transition Act (SB 1547B):

- Mandates that any load serving entity in the state like PGE must end energy sales coming from coal by the year 2035. This has led PGE to announce the retirements of its Boardman and Colstrip coal plants within the next 2 and 10 years, respectively.
- Mandates a Renewable Energy Portfolio Standard (RPS) of 50% by 2040, meaning that 50% of energy sales must come from qualifying renewable sources.

2007 HB 3543:

- Aims to achieve greenhouse gas levels at least 75% below 1990 levels by 2050.

1.2 Existing PGE System

As of 2019, PGE covers a service territory of 4,000 sq. miles in and around the City of Portland, Oregon. The utility serves approximately 887,000 customers including 772,389 residential customers, 109,107 commercial customers and 270 industrial customers. PGE serves 44% of the total population in Oregon and distributes its power across six counties -Multnomah, Clackamas, Marion, Yamhill, Washington, and Polk. The utility's retail sales totaled 21 million MWh with an average retail rate of 12.01 cents/kWh. PGE's carbon emissions stand at 430 $kgCO_2$/MWh in 2019.

Current Capacity Mix: PGE meets its energy demand with a diverse mix of generation resources such as hydro power, natural gas, coal, wind, and solar plants that are fully or jointly owned by the utility. PGE's total capacity in 2019 was 4394 MW with Natural Gas making up most of the share (48%) followed by Wind, Hydro, and Coal each taking approximately 15% to 21% of the mix. Solar and Batteries (Storage) are currently at less than 1%. Table 1 shows the capacity (MW) of each resource type and Figure 1 shows the capacity distribution (%) in a pie-chart.

Table 1. PGE resource capacity mix and percentage share

Hydro	Coal	Natural Gas	Wind	Solar	Storage	Total Resources
646 MW	938 MW	2086 MW	717 MW	2 MW	5 MW	4394 MW
15%	21%	48%	16%	0.04%	0.11%	100%

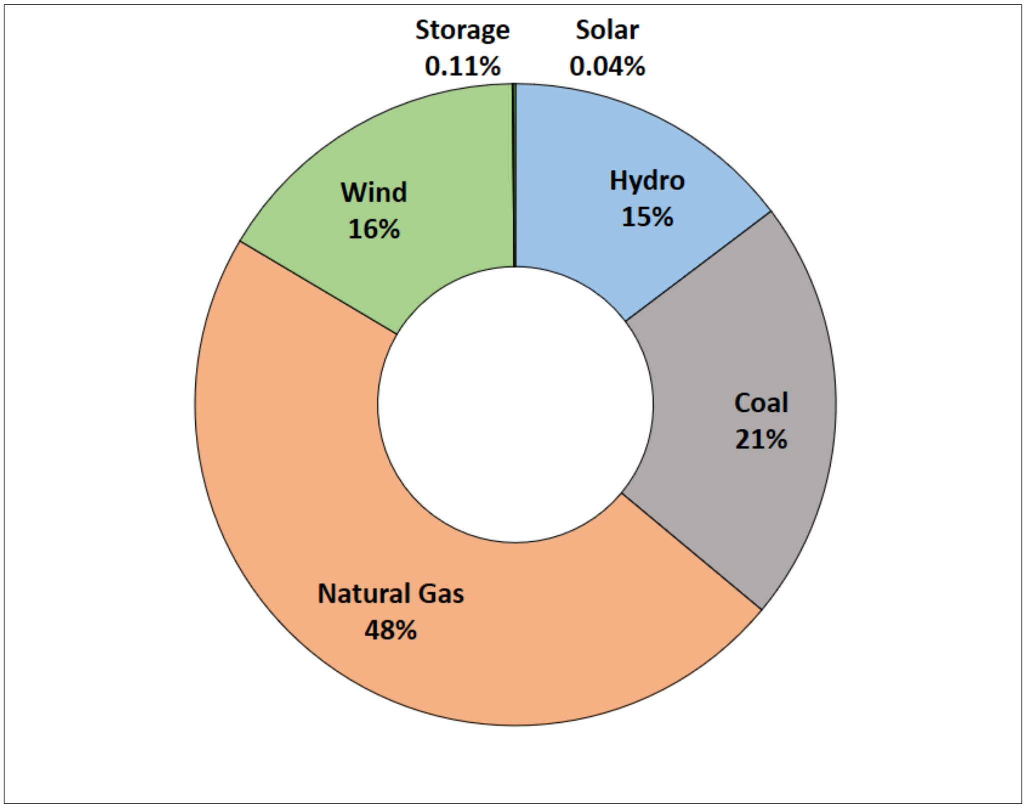

Figure 1. Pie-chart represents PGE's 2019 Capacity Mix

1.3 Resource Need Assessment

An integral part of the IRP is to first identify the gaps between the available resource capacity and the additional resources needed in the future to ensure uninterrupted supply of electricity to the customers. Additional resources are based on demand projections into the future years. This needs to be estimated while meeting the policy and emission reduction requirements.

Regression analysis: We performed a regression analysis for projecting peak demand and resource capacity till 2050 using PGE historical data (Fig. 2). Details of this analysis are elaborately described in Section 3 of this report. Projections indicate PGE's peak demand will grow from 3900 MW in 2019 to approximately 4900 MW in 2050. This shows that a peak demand growth of at least 1000 MW in the next 30 years. Now, assuming that the scheduled retirement of power plants will take place as expected, we estimate that the capacity will decrease from 4394 MW in 2020 (Table 1) to 550 MW in 2050 (Fig. 2). This leaves a resource capacity gap of at least 4350 MW in 2050. This gap (also known as resource need) is met through new capacity additions that is proposed and modeled in the IRP.

Furthermore, demand projections indicate that the energy sales will grow from 21,000 GWh in 2019 to 27,000 GWh in 2050, implying that sales will rise by 6,000 GWh in the next 30 years.

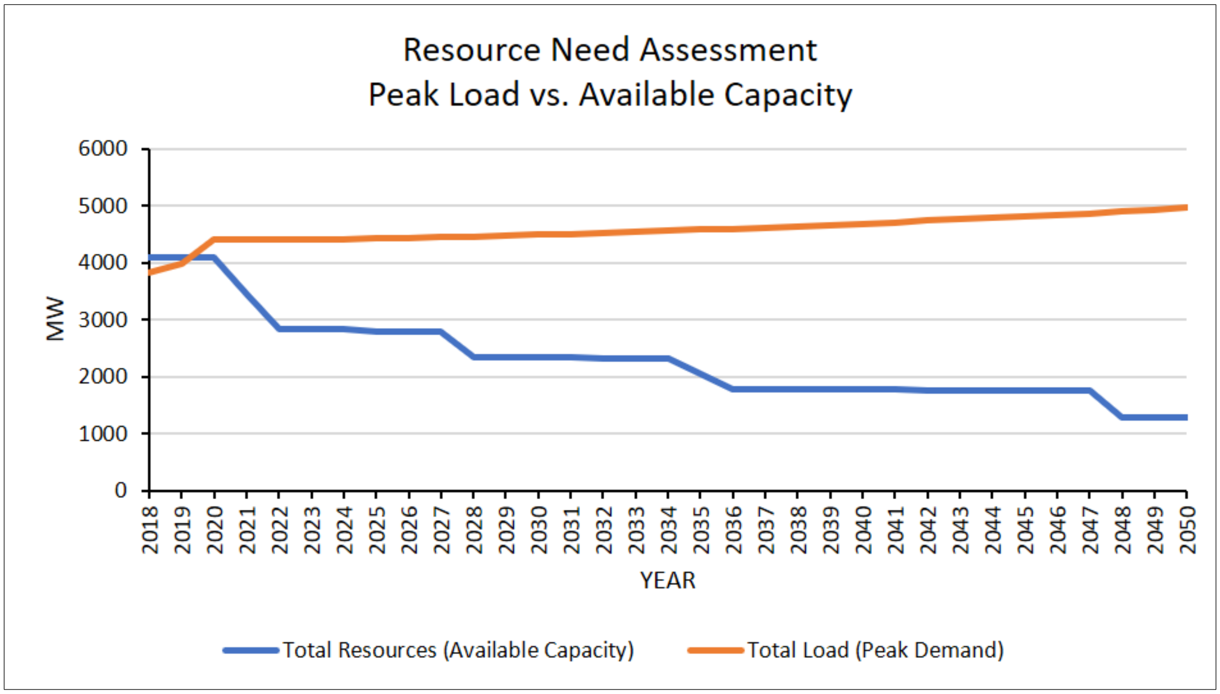

Figure 2. Graph indicating peak demand vs. available capacity for PGE from 2018 to 2050.The gap between the orange and blue line indicates the resource need.

2. Scenarios

2.1 Overview

Our IRP research goal is to achieve a zero-emissions end-target by 2050 for PGE. We are trying to the determine the best path for PGE to achieve this target, specifically, to find a least-cost, least-risk optimal resource mix to meet the zero-emissions target by 2050. We consider three scenarios in this IRP- (1) Reference Scenario, (2) High-Renewables scenario and (2) Carbon Capture Sequestration (CCS) scenario. A direct comparison between the results from High-Renewables scenario and the CCS scenario will reveal the differences in annual cost, retail price of electricity, emissions intensity etc. between the two cases. This will help understand which of the two cases is a better approach for PGE to meet the zero-emissions goal. For the scope of this project, we have considered capacity build- outs or modeling at regular 10-year intervals starting in 2020, then 2030, 2040, and finally 2050.

2.2 Reference case

The Reference case is a scenario where PGE meets future capacity needs at the lowest cost with business as usual operations. In other words, here, we are only aiming for the system to achieve minimum policy requirements- (1) the state RPS requirements of achieving 50% renewables by 2040, (2) No new coal plants will be considered after the existing plants retire. Additionally, since neither geothermal nor nuclear energy are a part of PGE's current mix of resources, we are excluding them from this scenario as well as the other scenarios explored in our model. Since the Reference case is not constrained by a zero emissions goal, fossil fuel generation will still be a part of the electricity system in this scenario.

2.3 High Renewables case

The High-renewables case is aimed at achieving zero-emissions by 2050, with a high penetration of renewable resources in the capacity mix. The suite of resources considered for this case are wind, solar, hydro, and biomass; the zero-emissions target is achieved by progressively adding various amounts of renewable capacity at regular intervals of 10 years. Biomass is a carbon neutral fuel, hence it neither adds nor removes any carbon emissions. However, since biomass is considered a renewable resource under the state guidelines of Oregon, it adds successfully to the renewable share of the new capacity mix. Through this scenario, we target to have a 100% renewable energy mix by 2050.

2.4 Carbon Capture Sequestration case

The Carbon Capture and Sequestration Case (CCS) is aimed at achieving zero-emissions by 2050. Unlike the High Renewables case, this case will primarily rely on building Natural Gas-plus-Carbon Capture and Sequestration (Gas+CCS) power plants with a much lesser leverage on renewables. Although the scenario allows for solar, wind, and hydro generation on a need basis, the major capacity additions will be accomplished through Gas+CCS technology.

2.5 Summary

Fig. 3. shows a list of criteria considered in each planning scenario. Main research questions we plan to address are:

- Which case is more cost-effective or cheaper to achieve zero-emissions by 2050?
- How do ratepayer prices change in each case? Are they higher or lower as compared to the Reference case?

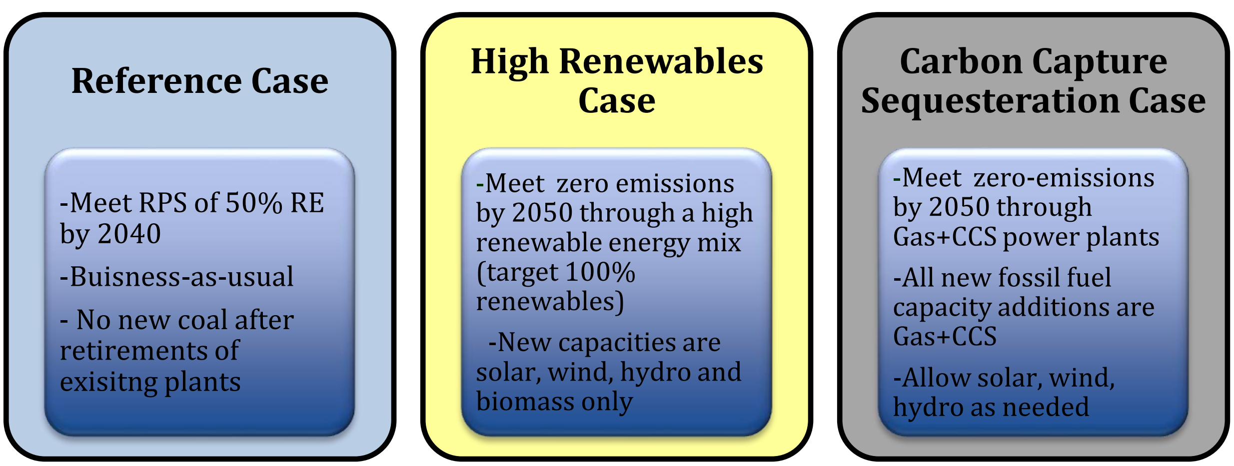

Figure 3. Description of all three cases considered

3. Models and Methods

Summary: We relied heavily on data from FERC, NREL, the EIA, other government agencies, and previous IRPs from PGE. These provided the raw data on the utility and the geographical region, for example, PGE's historical energy data, economics, and Oregon demographic data. Using this information/data we built a Load and Resources table. The Load and Resources table included several components- (1) projected load growth till 2050 (using regression model), (2) existing capacity information, (3) projected capacity till 2050, (4) estimated resource need. A Capacity Expansion model served as the central part of this IRP modeling and forecasting process. Data from the Load and Resources table provided as the main input into the capacity expansion model (stack model). We used Load Duration curves and Screening curves to choose the lowest cost build out of thermal resources. NREL solar prospector, System Advisor Model (SAM) and wind prospector were used to select potential solar and wind sites. With logical inputs and settings, a load profile was obtained for both solar and wind resources. The load profile was scaled up to match the intended capacity build out. Annual costs were calculated using data obtained from NREL's ATB sheet (Annual Technology Baseline), these included fixed and variable costs, capital recovery factor, heat rate and fuel costs. Fig. 4 shows a schematic representation of the steps used in the process.

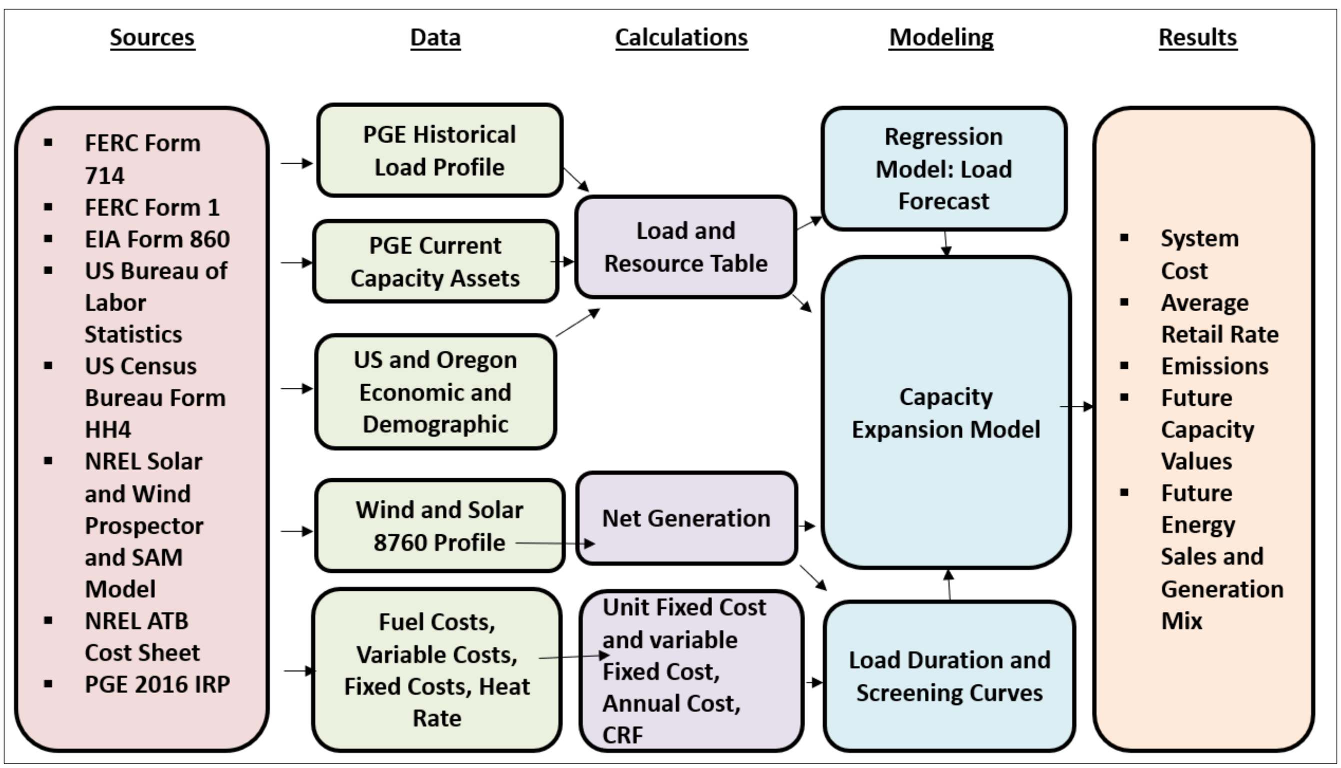

Figure 4. Method and modeling steps

3.1 Load Forecast model

The Load Forecast model shows the load projection in Oregon from 2020 to 2050. This was done by projecting PGE's annual load growth from 2020 to 2050 using a statistical regression model. The types of load growth forecast were- (1) total annual energy consumption and (2) annual peak demand. The regression analysis used historical data (1990 to 2019) of three variables- (1) U.S. Gross Domestic Product (GDP), (2) U.S. average household size and (3) Oregon population. Historical energy data was obtained from the FERC's eCommission library and FERC Form 714. FERC Form 714 provides yearly 8760 load data profiles from 2006-2018, while the eCommission library provides annual load profiles from 2005 and earlier. The load profile for 2019 was obtained through the U.S. EIA data sets and filtered for the utility concerned. GDP data was obtained from the U.S. Bureau of Labor Statistics and the U.S. Census Bureau served as the source for obtaining the Oregon population data.

Step 1- Projecting state population growth: An X-Y plot was obtained for the historical population in Oregon, which exhibited a linear trendline (equation y= 0.0443x + 2.9057; Fig. 5). Assuming a linear growth rate into the future and holding the slope constant, we extrapolated the trendline further until 2050. As per the projection, Oregon's population rises from 4.2 million in 2020 to approximately 6.7 million 2050.

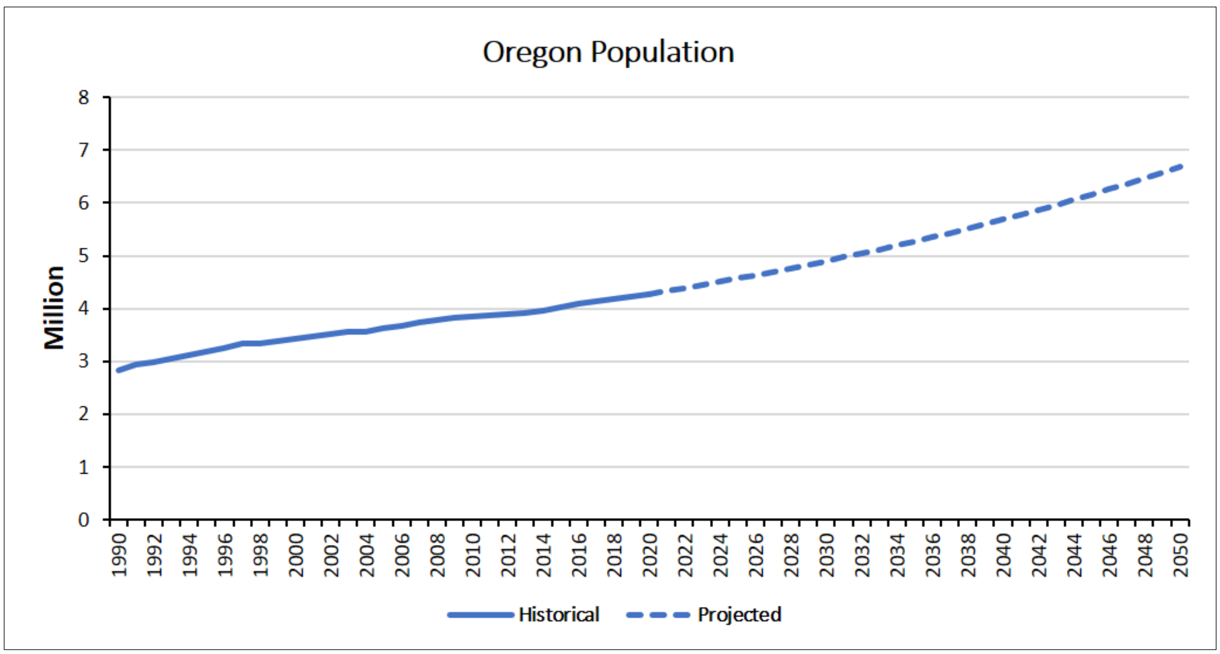

Figure 5. Plot showing historical Oregon population and projected Oregon population.

Step 2- Projecting U.S. GDP growth: An X-Y plot is obtained for the historical U.S GDP, which exhibited a linear trendline (equation y=518.77x + 4643.1; Fig. 6). Assuming a linear growth rate into the future and holding the slope constant, we extrapolated the trendline further until 2050. As per the projection, U.S. GDP rises from \$20,890 billion in 2020 to \$37,440 billion in 2050.

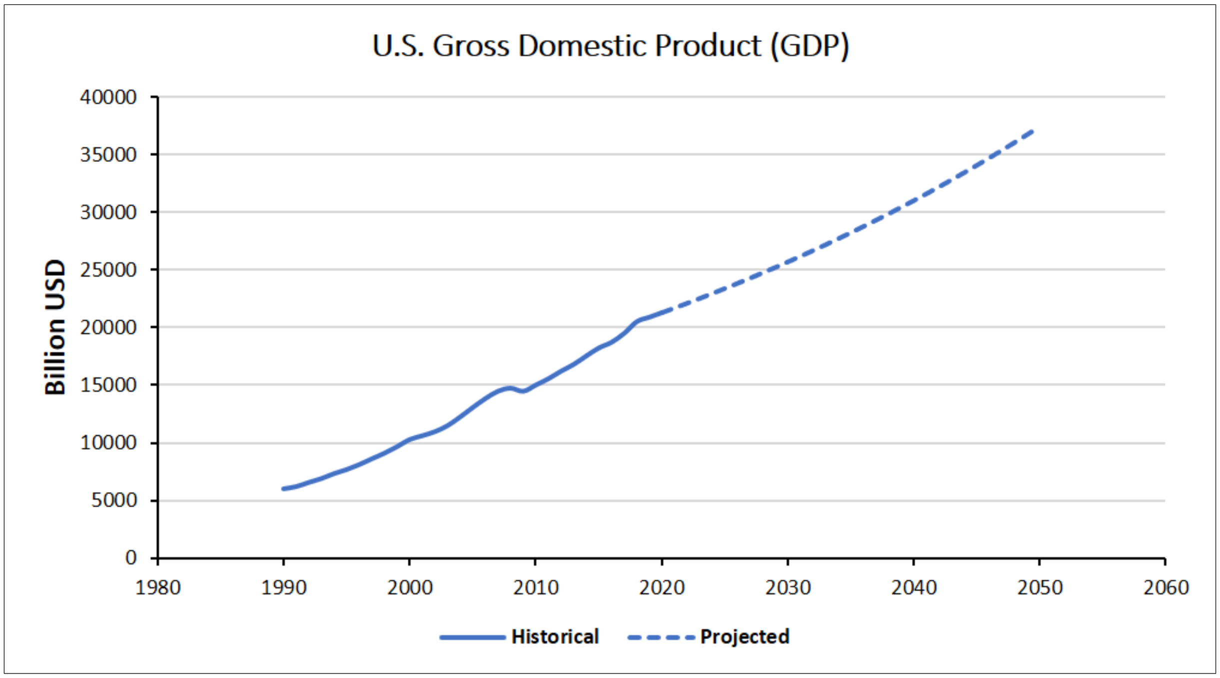

Figure 6. Plot showing historical U.S. GDP and projected U.S. GDP.

Step 3- Projecting U.S. average household size: An X-Y plot was obtained for the historical U.S. average household size, which exhibited a linear trendline (equation y=-0.0044x + 2.6531; Fig. 7). Assuming a linear growth rate and constant slope, we extrapolated the trendline further until 2050. As per the projection, U.S. average household size decreases from 2.52 people in 2020 to 2.38 people in 2050.

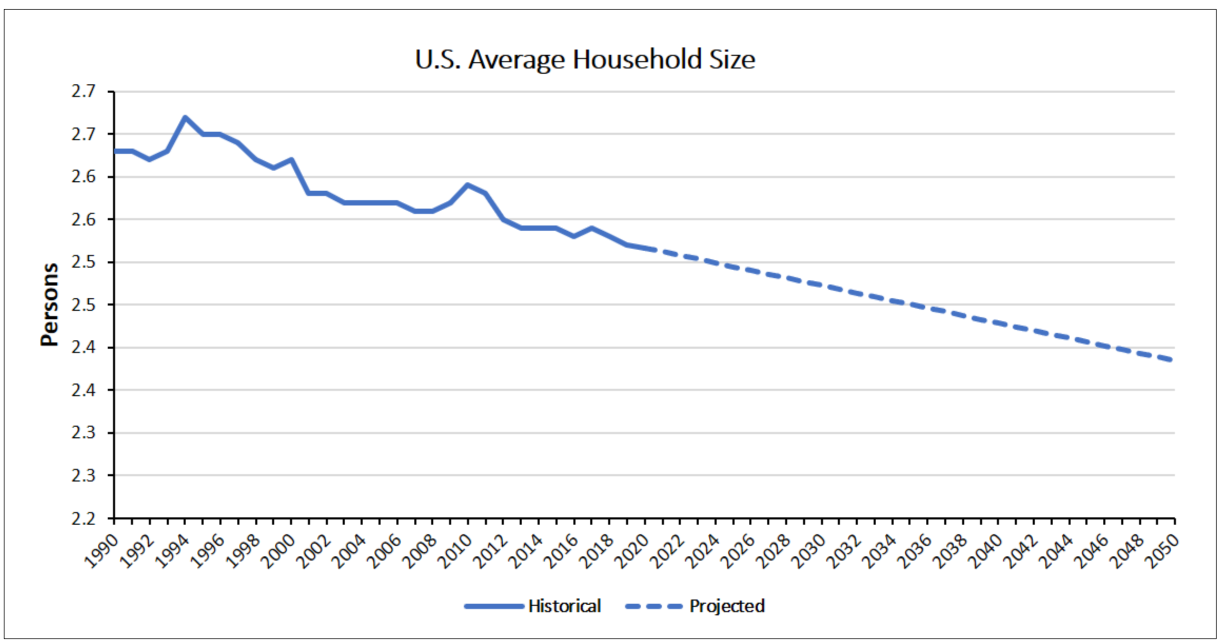

Figure 7. Plot showing historical U.S. average household size and projected U.S. average household size

Step 4- Projecting PGE energy data: We performed a regression analysis on all the data mentioned in Steps 1, 2,3 against the PGE annual load profile. MS-Excel Data Analysis tool was used for the analysis where PGE historical energy data was set as the y-variable and DP, population and household size were set as the multiple x-variables. Table 2 show the regression analysis statistics.

Below is the regression equation we used in the analysis:
Future Energy = intercept + (GDP coefficient*period year GDP) + (Oregon population coefficient*period year population) + (average household size coefficient*period year household size)

Table 2. Main statistics from the regression analysis of PGE energy data

	Coefficients	Standard Error	t Stat	P-value
Intercept	72948.7	15291.2	4.8	6.16E-05
US GDP (Billions)	-0.3	0.1	-2.4	0.025622
Oregon Population (Million)	3494.0	1490.4	2.3	0.026977
US Average Household Size	-23700.5	5721.2	-4.1	0.000322

Regression Statistics	
Multiple R	0.87
R Square	0.76
Adjusted R Square	0.73
Standard Error	493.08
Observations	30

Plugging in the forecast x-variables values for each year in the equation, we obtained the energy demand for that year. Annual energy forecast for 2020 to 2050 can be seen below in Fig. 8 and Fig. 9. The total annual energy demand is expected to grow from approximately 21,000 GWh in 2020 to 27,000 GWh in 205, while the annual energy peak demand is expected to rise from approximately 3900 MW in 2020 to 4900 MW in 2050.

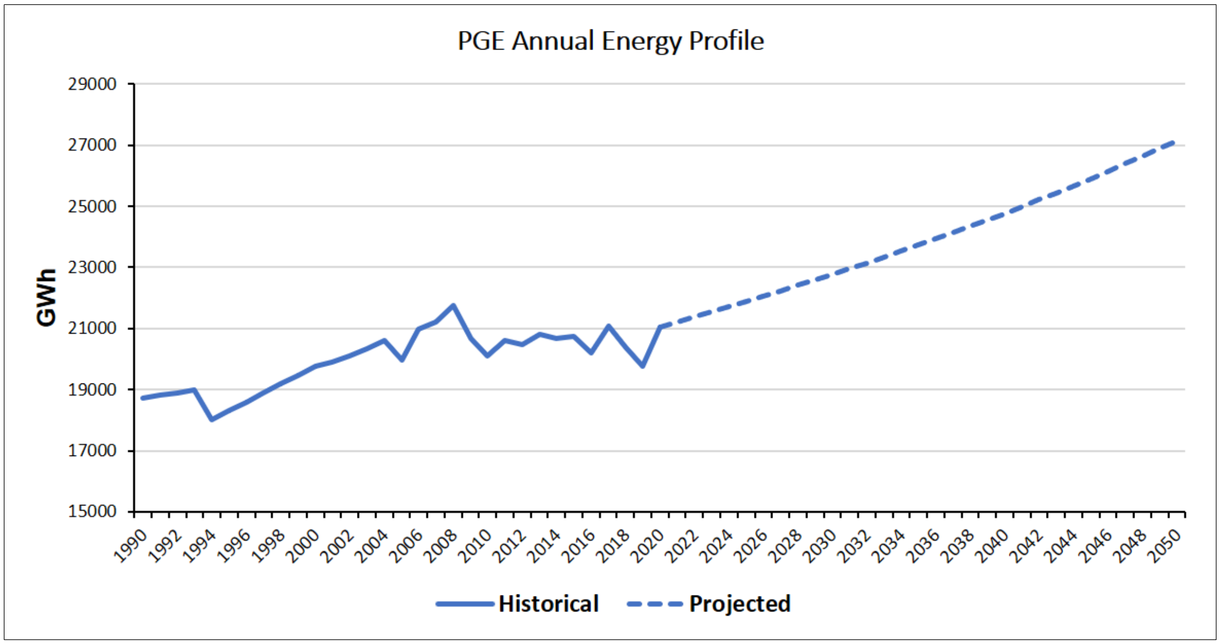

Figure 8. PGE historical annual energy profile and projected annual energy profile

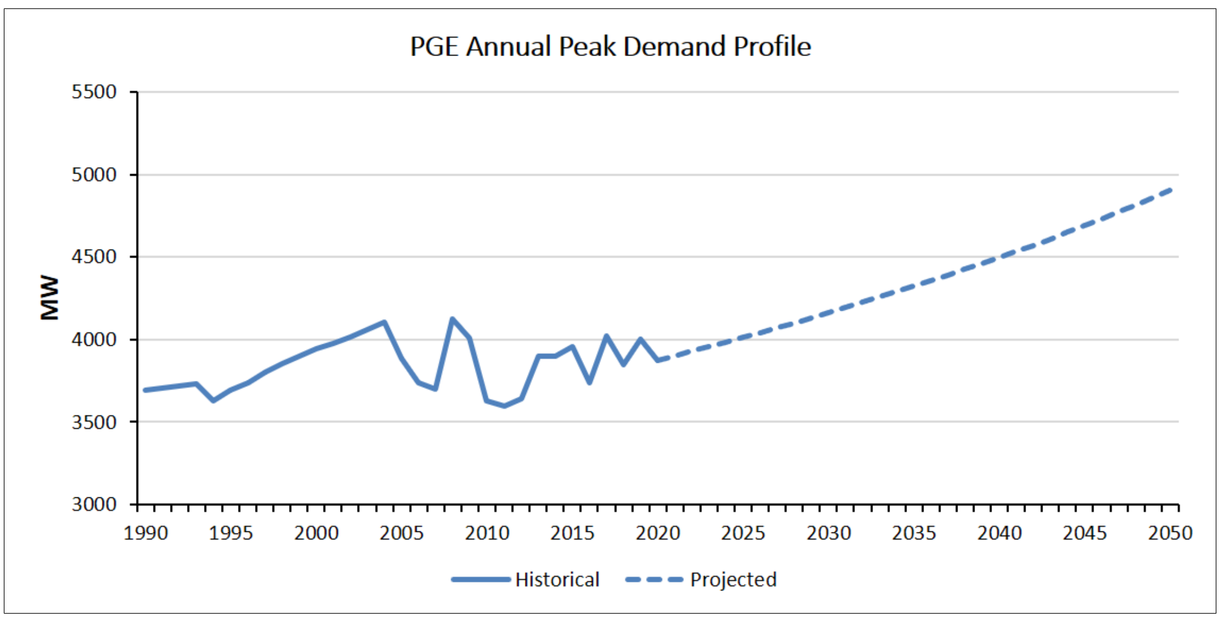

Figure 9. PGE historical annual peak energy demand and projected annual peak energy demand

3.2 Energy Efficiency and Demand-Response

Energy efficiency (EE) procurement data (projections from 2020 to 2036) was directly obtained from the Energy Trust of Oregon study within the PGE 2016 IRP report (Table 3). This data shows that PGE will obtain varying amounts of cost-effective energy efficiency from 2020 through 2036. Since the PGE 2016 IRP report did not contain any EE data projections beyond 2036, we assumed a constant yearly EE acquisition equal to the quantity that will be acquired in 2036. We obtained the Distributed Energy Resources (DR) data projections directly from the 2016 PGE IRP report (Table 4).

Table 3. Energy Efficiency data projections from 2020 to 2050

Year	New EE	Cumulative EE	Year	New EE	Cumulative EE
2020	29.5	29.5	**2036**	13.5	315.6
2021	27.1	56.6	**2037**	13.5	329.1
2022	24.4	81	**2038**	13.5	342.6
2023	23.5	104.5	**2039**	13.5	356.1
2024	21.5	126	**2040**	13.5	369.6
2025	20.8	146.8	**2041**	13.5	383.1
2026	19.3	166.1	**2042**	13.5	396.6
2027	18.4	184.5	**2043**	13.5	410.1
2028	16.3	200.8	**2044**	13.5	423.6
2029	15.8	216.6	**2045**	13.5	437.1
2030	14.6	231.2	**2046**	13.5	450.6
2031	14.8	246	**2047**	13.5	464.1
2032	14.4	260.4	**2048**	13.5	477.6
2033	14	274.4	**2049**	13.5	491.1
2034	13.9	288.3	**2050**	13.5	504.6
2035	13.8	302.1			

Table 4. Distributed Energy Resources data projections from 2020 to 2050.

Year	DER	Year	DR
2020	-11	**2036**	-37
2021	-12	**2037**	-39
2022	-13	**2038**	-42
2023	-14	**2039**	-45
2024	-15	**2040**	-48
2025	-17	**2041**	-51
2026	-18	**2042**	-54
2027	-19	**2043**	-57
2028	-21	**2044**	-61
2029	-22	**2045**	-64
2030	-24	**2046**	-68
2031	-26	**2047**	-72
2032	-28	**2048**	-76
2033	-30	**2049**	-80
2034	-32	**2050**	-84
2035	-34		

3.3 Existing Capacity and Generation Plants

EIA Form 860 Generator Sheet is available from the EIA website and it provides independent yearly data for all U.S. electric utilities from 2001 to 2018. We extracted the relevant generation and capacity data for PGE from EIA Form 860. This included data for all- (1) all generation plants, (2) all generators for each plant, (3) nameplate capacity, (4) commercial operation/ installation and retirement years for every generator present in each resource type. Furthermore, we consolidated some of the generators based on their resource type and similar installation and retirement years to obtain the aggregated capacities for the generators (Table 5).

Table 5. Existing PGE generator and capacity table.

Generator	Online	Offline	Type	Capacity (MW)
Faraday 1	1907	2020	Hydro	17.4
Faraday 2	1958	2058	Hydro	19.2
North Fork	1958	2058	Hydro	40.8
Pelton	1957	2057	Hydro	109.8
River Mill 1	1911	2020	Hydro	9.9
River Mill 2	1927	2027	Hydro	3.9
River Mill 3	1952	2052	Hydro	5
Round Butte	1964	2064	Hydro	372.5
Sullivan 1	1924	2024	Hydro	14.4
Sullivan 2	1952	2052	Hydro	1
Boardman	1980	2021	Coal	642.2
Oak Grove 1	1924	2024	Hydro	25.5
Oak Grove 2	1931	2031	Hydro	25.5
Coyote Springs	1995	2035	CT	266.3
Beaver 1	1974	2020	CCGT	586.2
Beaver 2	2001	2041	CCGT	24.5
Post Westward	2007	2047	CT	483
Post Westward Unit 2	2009	2049	CT	225.6
Big glow Canyon Wind Farm	2007	2027	Onshore Wind Turbine	449.7
Baldrock Solar Highway	2012	2037	Solar Photovoltaic	1.7
Carty Generating Station	2009	2049	CT	500
Tucannon River Wind Farm	2014	2034	Onshore Wind Turbine	266.8
Salem Smart Power Center	2013	2028	Batteries	5
Timothy Lake Powerhouse	2018	2118	Hydro	1.2
Colstrip	1984	2030	Coal	296
			TOTAL	**4394**

In the absence of retirement years in EIA Form 860, we assumed the following lifetime for common generating plants (Table 7). These assumptions are based on the average lifespan of these types of plants historically owned and operated by PGE.

Table 6. Lifetime assumptions for different PGE generating plants.

Natural Gas	Wind	Hydro	Solar	Batteries
40 Years	25 Years	100 years	30 years	15 Years

Based on the retirement years of existing plants and assuming no new resource additions, the existing available capacity is expected to go down from a 4394 MW in 2019 to 549.5 MW in 2050 (Table 8). The decreasing capacities of each resource type is graphically shown in Fig. 10.

Table 7. Existing capacity of various PGE resources- 2019 to 2050.

Year	Hydro (MW)	Coal (MW)	Natural Gas (MW)	Wind (MW)	Solar (MW)	Storage (MW)	Total (MW)
2019	646.1	938.2	2085.6	716.5	1.7	5	4394
2050	549.5	0	0	0	0	0	549.5

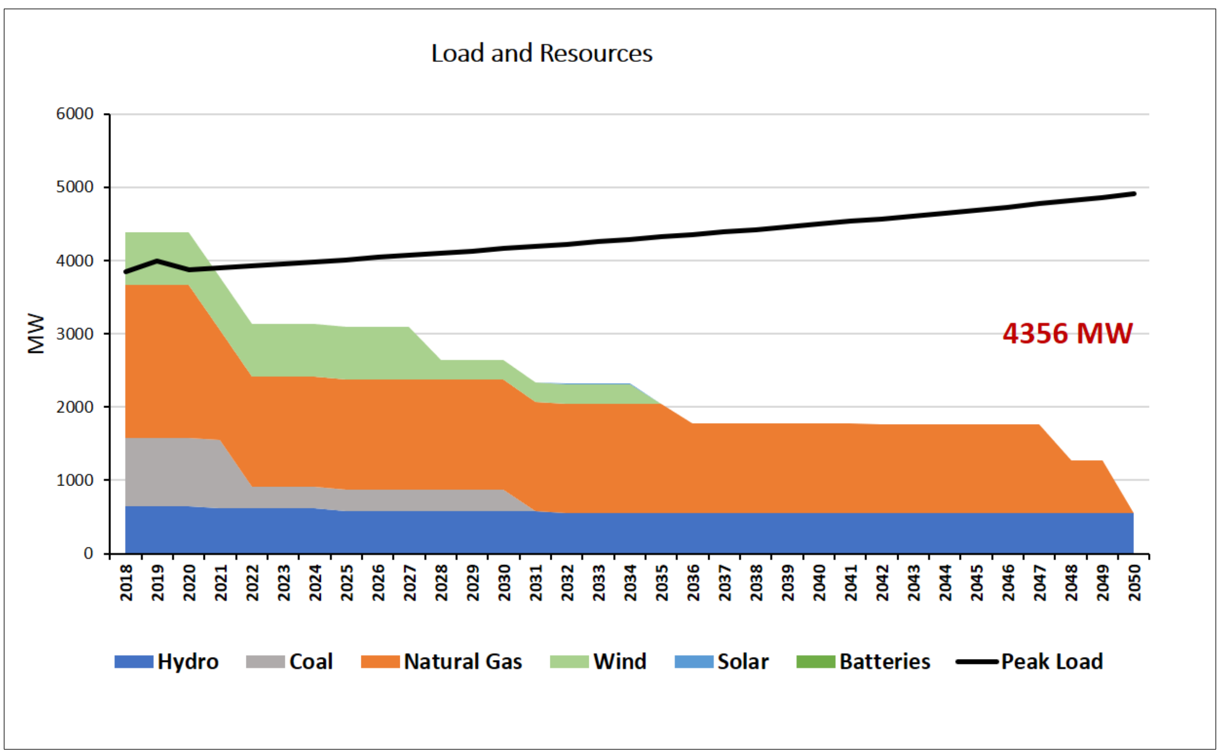

Figure 10. Load & Resource gap. Black line indicates PGE projected load growth. Colored stacks indicate decreasing capacities of various PGE resource types (2018 to 2050)

3.4 Load and Resource Table

A Load and Resources Table was formulated by combining all previously aggregated data- (1) load forecast, (2) EE and DR data, (3) existing capacity table (available resources). The Load and Resources table uses a 17% planning reserve margin to estimate the total capacity. It calculates the final system deficit for every year by taking the difference between the total capacity and total load projected for that particular year. The gap between the total load and total resource capacity (4356 MW) indicates the resource need assessment as shown previously in Fig. 10.

3.5 Capacity Expansion Model (Stack model)

Model overview: A stack model was used to perform capacity expansion for every ten years- 2020, 2030, 2040, and 2050. Primary inputs in the model were drawn from the Load and Resources table and include- (1) existing generators by capacity, online year and retirement year, (2) generators classified based on total cost, heat rate and capacities tranches, and (3) energy consumption and peak demand data from 2018 to 2050. Renewable capacity expansion was estimated for wind and solar resources based on Oregon's Renewable Portfolio Standard. Net generation was then calculated using the thermal and renewable capacity expansion estimates. We then used net generation to obtain load duration curves (LDC) and screening curves (SC). LDC and SC were used to determine the lowest cost 8760 dispatch of thermal resources. The 8760 dispatch numbers were then used to inform thermal resource capacity expansion. We used the Microsoft Excel Solver analysis tool to calculate the outputs. Primary output or decision variable was the new capacity of the generators for the year modeled. Other outputs included total renewable share, emission intensity, curtailment, and total system generation cost. The models are set to minimize the system generation cost and constrained by the specific requirements as per the different scenarios. Additionally, average retail rate of electricity was calculated based on the levelized cost of electricity (LCOE) in each scenario.

Solar capacity: We used the NREL modeling tool System Advisor Model (SAM) and obtained the 8760 load shape profile for solar generation in PGE service territory. A weather file for the City of Oregon was used as the base for the load shape simulation. We chose eight different locations for prospective solar plant installations and simulated an average scaled load shape profile. In-state site locations were preferably chosen to avoid any additional transmission costs. Inputs used in the SAM model were- (1) 15 degrees tilt (2) 180 degrees azimuth alongside a standard module type (3) 1.2 DC/AC and (4) 96% inverter efficiency.

Wind Capacity: To add wind capacity we used the NREL Wind Prospector tool and obtained an average scaled 8760 load shape profile for wind generation in PGE service territory. Weather data for the year 2010 was used as the base weather profile to match simulated data. Six prospective location sites were selected with respective capacity factors ranging between 33% to 40%. In-state site locations were preferably chosen to avoid any additional transmission costs.

Fixed and Variable cost data: Average cost data for each resource type was obtained from the NREL Annual Technology Baseline (ATB) document. Annual cost was calculated using the capex ($/kW), capital recovery factor (CRF), fixed cost and variable cost for operation and maintenance ($/kW-yr). Resource type specification used were- (1) Wind, TRG 1-mid, 0.49 capacity factor (CF), (2) Solar, TRG-mid, 0.16 CF (3) Coal-new-avg CF, 0.21 CF, (4) Natural Gas- CT-Constant CF, 0.33 CF, (5) Hydro, NPD-1 mid, 0 .40 CF, (6) Biomass, Dedicated Mid, 0.56 CF (7) Natural Gas+CCS, Gas-CC-CCS-Avg. ,0.61 CF.

Fuel Costs: While fuel costs for coal and natural gas were obtained from the NREL ATB document, biomass fuel cost was obtained from PGE's published research. Fuel costs for CCS power plants were treated differently. We assumed that CCS plants capture 90% of the CO_2 emitted into the atmosphere. To achieve zero emissions in our scenarios, we introduced a mix of 90% natural gas and 10% biogas. This was used as a fuel mix for the CCS plants in the 2050 zero emissions+ CCS scenario. Since capturing and storing biogas emissions achieves negative emissions, the escaped CO_2 emissions would be offset. We assumed a cost of $25/MMBTU for biogas fuel and $50/tonne of CO_2 for transportation and storage costs.

Transmission and Distribution (T&D) Costs: We assumed T&D costs to be the difference between the reported 2020 PGE average retail rate and our own calculation of the levelized cost of electricity for 2020. To determine the ratio between transmission and distribution we looked at PGE historical data for T&D costs as reported in FERC Form 1. After obtaining the total costs and the ratio, we assumed a fixed percent linear growth till 2050. A higher percentage growth assumption was used in scenarios with greater number of renewables in the system.

3.6 Determining Thermal Capacity

LDCs and SCs are important tools to determine the amount of thermal generation needed to meet load economically (Fig.11 and Fig.12). To create an LDC we took PGE's 8760 annual demand profile and sorted it from the highest to the lowest load hour (Fig. 11). A Screening Curve (cost curve) demonstrates the generation cost of a type of plant as a function of operation (Fig. 12). The fixed and variable costs for each generation type- coal, CCGT, CT, biomass, CCGT + CCS was first determined. The least-cost frontier of each generation type was then determined using these cost numbers (Fig. 12).

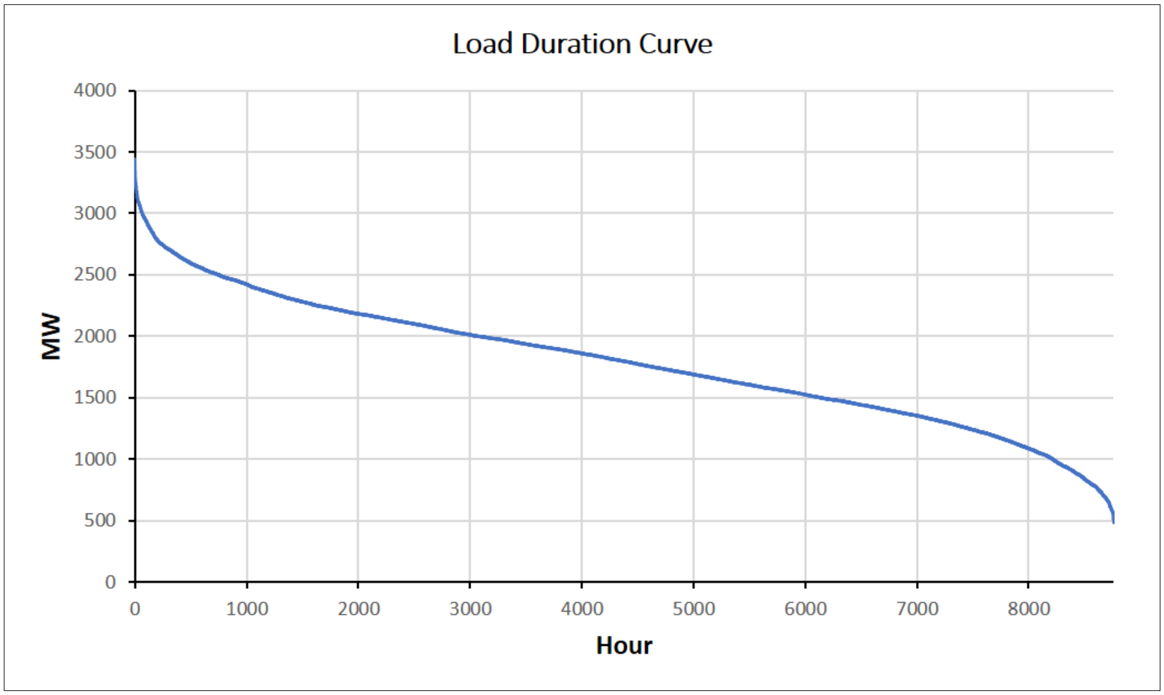

Figure 11. Load Duration Curve constructed using 8760 hourly data

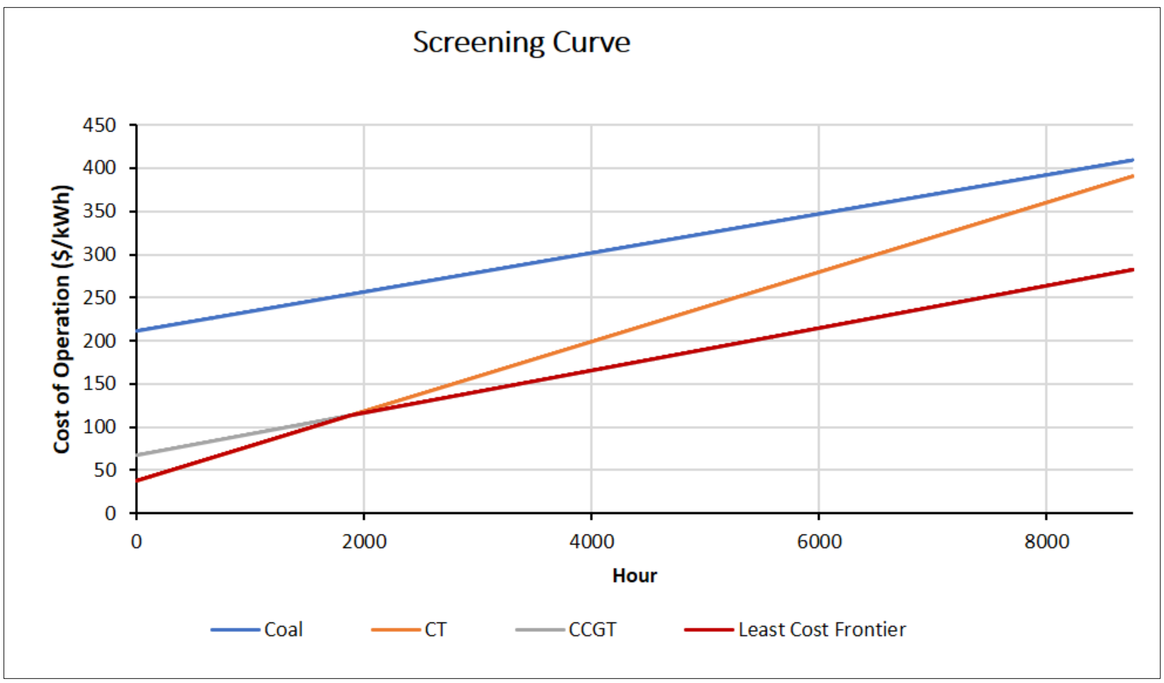

Figure 12. Screening Curve constructed for each thermal technology. Least cost frontier is determined using these curves and indicated here in red ink.

Overlay and 8760 Dispatch: The amount of each type of thermal resource needed to meet the net generation in the least-cost way was determined by using the LDC and SC. This is called the 8760 dispatch overlay and was constructed by the LDC data over the SC data in MS-Excel. As an example, below is the resulting 8760 dispatch capacity for the 2020 Reference Case. The model selected most of the capacity build out to be CCGT, followed by CT, and no Coal (Fig. 13). The capacity values obtained in the 8760 Dispatch were then used as inputs in the Capacity Expansion Model to optimize the total new capacity needed for the test year.

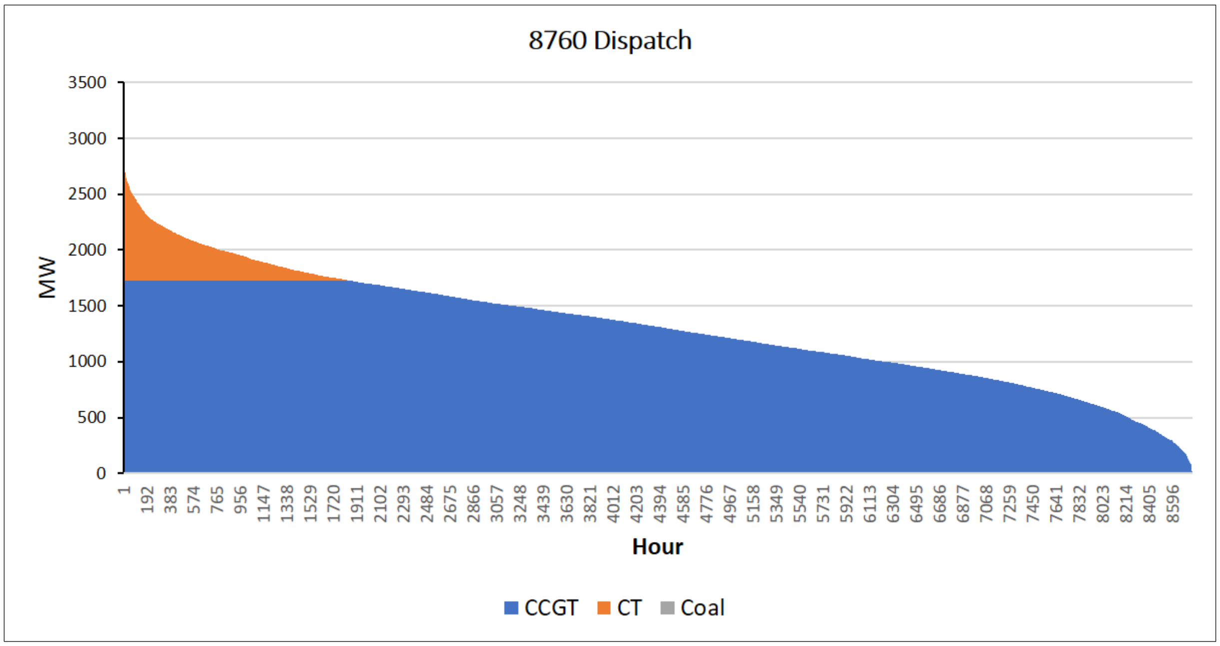

Figure 13. Overlay of LDC and Screening Curve to produce an 8760 dispatch

4. Results & Modeling Outcomes

The overall results summary obtained from the modeling process is shown below in Table 8.

Table 8. Summary of results obtained for all cases

	Reference Case 2020	Reference Case 2050	High Renewable Case 2050	Carbon Capture Seq. Case 2050
System Overview				
Peak Demand (MW)	3873	4906	4906	4906
Nameplate Capacity (MW)	5467	9373	11571	10544
Dependable Capacity (MW)	4531	5739	5738	5738
Energy Sales (MWh)	21,040,958	27,437,876	30,708,016	29,385,919
RES Energy (MWh)	5,370,624	15,037,266	23,077,264	20,272,556
RES Share %	26%	55%	85%	75%
Carbon-free energy (MWh)	5,370,624	15,037,266	23,077,264	20,272,556
Carbon-free share %	26%	55%	100%	100%
Emissions (MMT)	8.51	4.25	0.00	0.00
Emission Intensity ($kgCO_2/MWh$)	405	155	0	0
Curtailment (MWh)	0	287,857	3,557,998	2,235,901
Curtailment Share %	0%	2.41%	20.44%	14.28%
System Costs				
Fixed Gen Costs (mill$)	753	957	1431	1639
Variable Gen Costs (mill$)	358	220	363	369
Distribution Costs (mill$)	853	1150	1436	1334
Transmission Costs (mill$)	568	765	956	888
CCS storage+ transportation (mill$)	-	-	-	181
Total Costs (mill$)	2532	3092	4186	4411
Average Retail Rate ($/kWh)	0.12	0.11	0.15	0.16
Nameplate Capacity				
Coal (MW)	938	0	0	0
CCGT (MW)	1386	3276	0	0
CT (MW)	1773	1744	0	0
CCGT+CCS (MW)	0	0	0	4843
Wind (MW)	717	2396	3402	3227
Solar (MW)	2	1066	1844	1153
Hydro (MW)	646	890	1624	1321
Biomass (MW)	0	0	4701	0
Total (MW)	5467	9373	11,571	10,544
Net Generation Share				
Coal	29.5%	0.0%	0.0%	0.0%
CCGT	43.4%	45.1%	0.0%	0.0%
CT	1.6%	0.1%	0.0%	0.0%
CCGT+CCS	0.0%	0.0%	0.0%	31.0%
Wind	14.8%	37.9%	48.1%	47.7%
Solar	0.0%	5.5%	8.6%	5.6%
Hydro	10.7%	11.3%	18.5%	15.7%
Biomass	0.0%	0.0%	24.8%	0.0%

4.1 Nameplate Capacity, Dependable Capacity and Net Generation

Nameplate capacity, also known as rated capacity or installed capacity, is the maximum power output that a power plant can produce. In other words, it is the maximum capacity a power generator is designed to run at under ideal conditions. However, the final energy generated from a power plant, also depends on other factors besides the nameplate capacity. These factors include the CF (i.e., capacity factor) of the generators as well as the dispatch over a given period. Fig. 14 below shows the nameplate capacity of the three cases across the modeling period. The nameplate capacities rise incrementally over time to meet the growing load from 2020 to 2050.The High Renewables case shows the highest nameplate capacity additions from 2020 to 2050 reaching 11,571 MW in 2050.

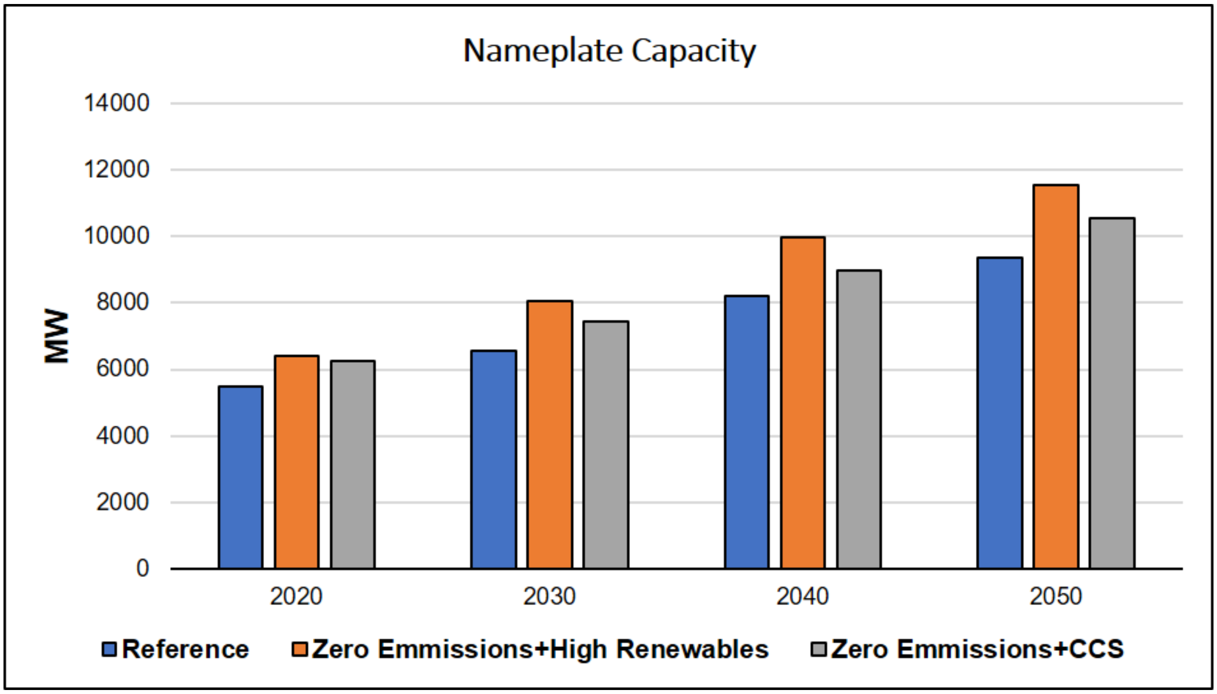

Figure 14. Nameplate Capacity of all cases from 2020 to 2050

The dependable capacity is defined as the load carrying capacity or the baseload capacity of a power plant that can be sustained during a restricted period of time. These restrictions often include seasonal variations affecting load, power outages, maintenance etc. Since it is always a portion of the total nameplate capacity, it should at least be equal to the planning reserve margin of the system.

Fig. 15 shows the peak load, dependable capacity, and total nameplate capacity in the three cases for the year 2050. Due to the intermittency and variability of renewables, solar and wind do not serve the dependable capacity as reliably as natural gas plants. Adding greater renewable capacity thus requires parallel building of greater natural gas capacity. It is needed in order to obtain adequate dependable capacity. This can be seen in the High Renewables case, where the dependable capacity makes up a large portion i.e., almost half of the total nameplate capacity.

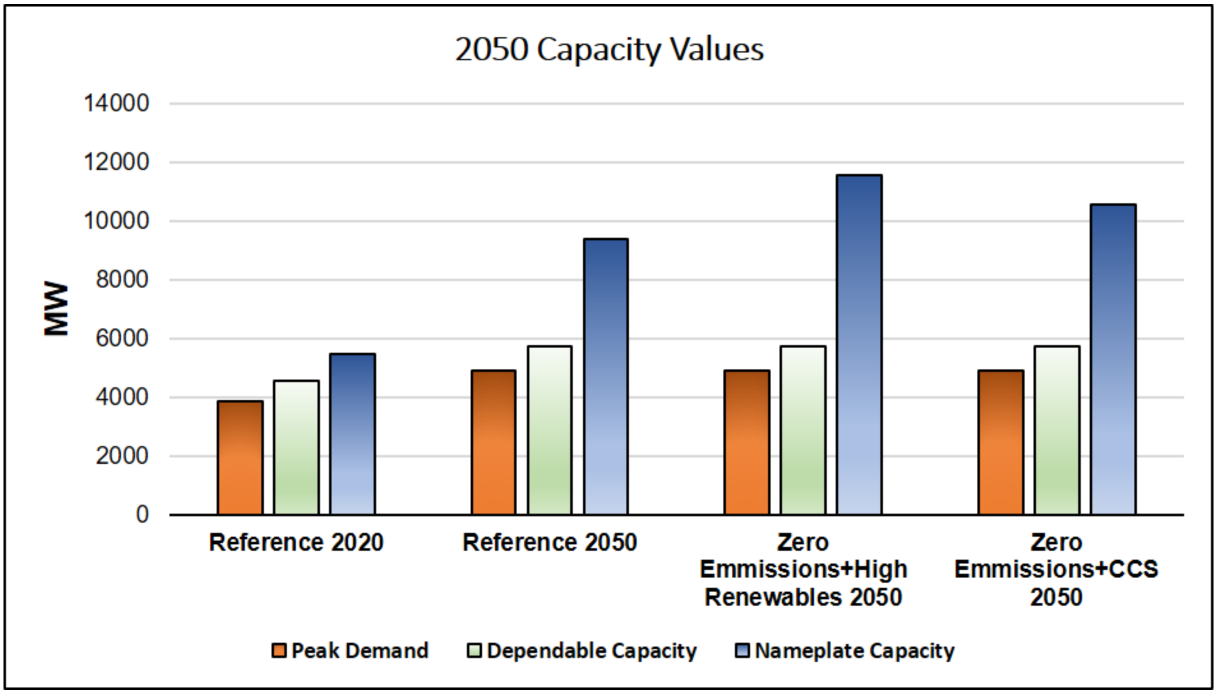

Figure 15. Relationship between peak demand, nameplate capacity and dependable capacity in all cases

While nameplate capacity refers to the maximum instantaneous power, the net generation is the actual energy produced over a time period to meet demand. Fig. 16 and 17 show the total nameplate capacity and the net generation share of various resource mixes in the three cases for 2050. Thermal resources such as coal and natural gas make up most of the energy mix in the 2020 Reference case, however, with an RPS target in due course, renewables are added progressively to the energy mix by 2050. The High Renewables case builds out a higher amount of solar and wind in order to meet the zero-emissions target while the CCS case builds out a significant amount of CCGT+CCS plants in order to achieve the same.

The share of renewables in the total capacity mix is often different from the share of renewables in the total generation mix. This is because of the variability in solar and wind generation. Large amounts of solar and wind production may exceed the amount of load during a time period, which can lead to unintended curtailments. To ensure justifiable and reasonable results, we limited curtailment to ~20% in all modeled years across all cases in the capacity expansion model. Because of the high share of renewables in the High Renewables approach, it has the highest curtailment among all cases. The curtailment in the High-Renewables Case is ~20% while the CCS case is ~14%.

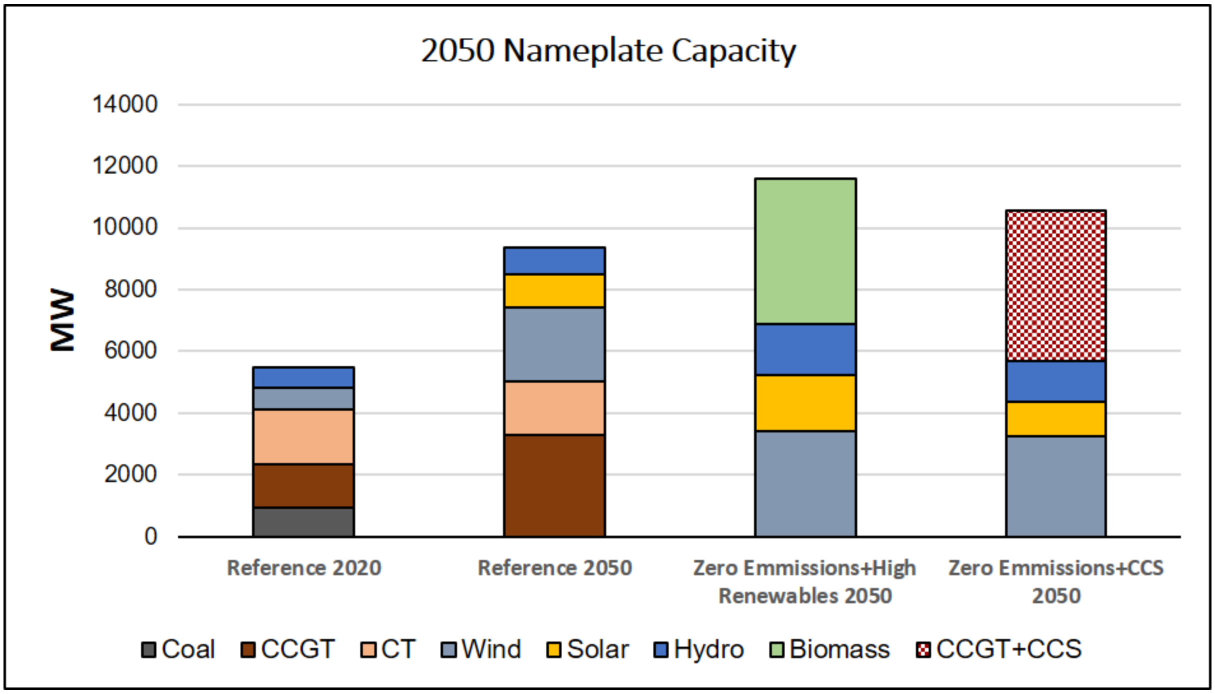

Figure 16. Breakdown of nameplate capacity (2050) by the various energy resources in all cases

While the High Renewable case displays a generation mix composed of 85% renewables (solar, wind, hydro) in 2050, the CCS Case shows a generation mix composed of 75% renewables (solar, wind, hydro) in 2050. In the High Renewables case, biomass makes up the remaining 15% of the generation mix. Since biomass is classified as a renewable resource under the state of Oregon, the system in this scenario would technically qualify as a 100% renewable mix.

Both the High Renewables case and CCS case show their highest generation share met by wind resources at approximately 48%. This is followed by 26% biomass in the High Renewables case and 31% CCGT+CCS generation in the CCS case. Solar generation makes up around ~9% while hydro is approximately at ~16% of the total generation mix in both cases.

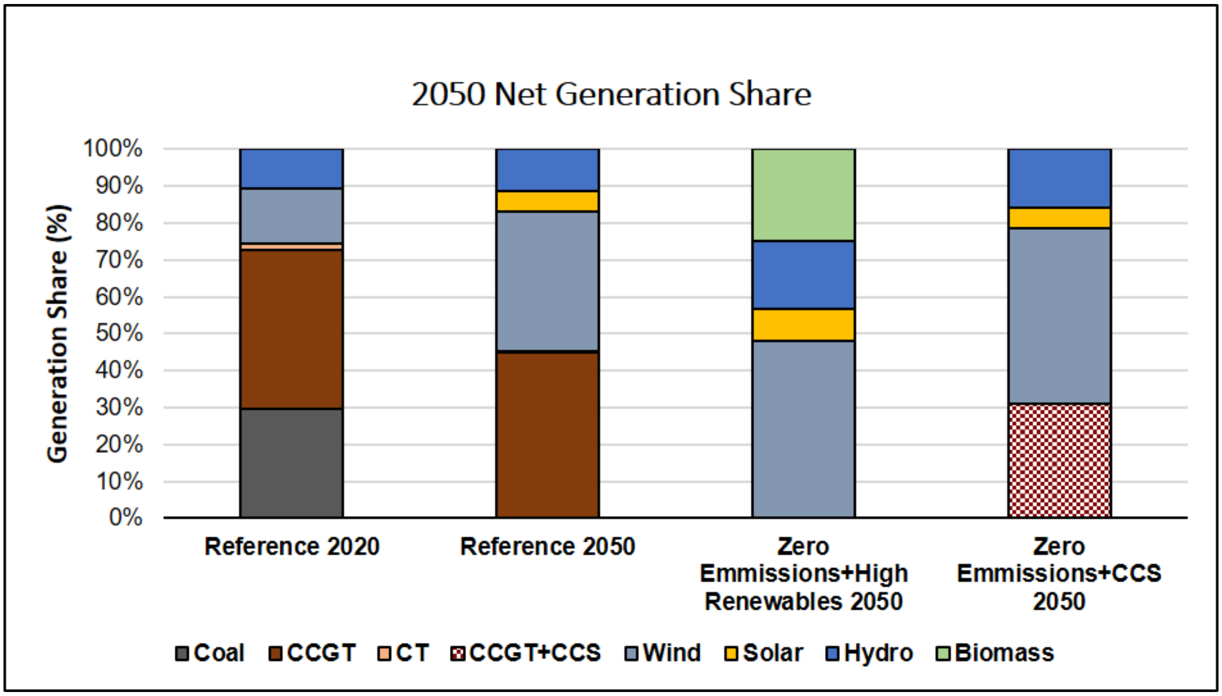

Figure 17. Net generation share of different energy resources in all cases (2050 to 2050)

4.2 Annual System Costs and Retail Rates

As overall capacity grows from 2020 to 2050, the system cost also grows alongside the capacity expansion. Fig. 18 demonstrates the overall rising system costs in the three cases.

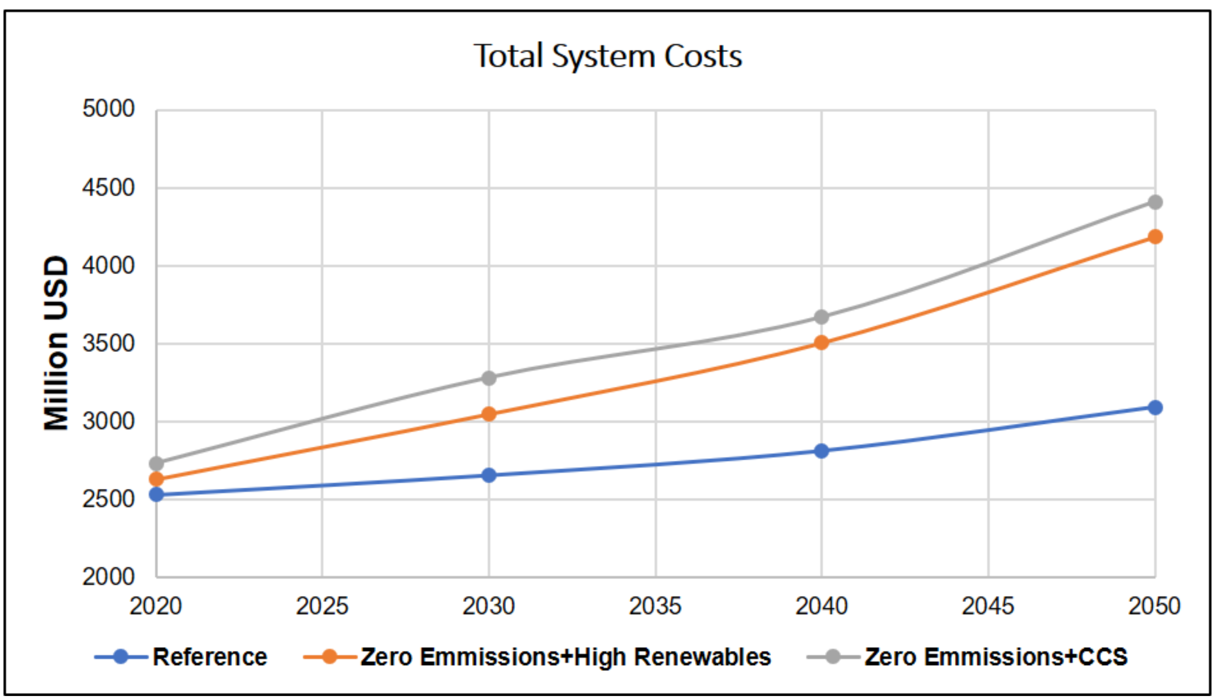

Figure 18. Total system costs in all cases from 2020 to 2050

Both the High Renewables case and the CCS case show much higher system costs relative to the Reference case. This is because of the higher renewable penetration and expensive technologies integrated in both scenarios. The CCS case shows the highest system cost at $4,411 million followed by the High Renewables Case at $4,186 million. Fig. 19 shows the breakdown of the 2050 total system costs in all three cases. System costs include fixed generation costs, variable generation costs, and T&D. Since renewables have high fixed costs and high T&D costs, the total system cost rises by a significant amount for both the High Renewables case and the CCS case. The highest system costs are seen in the CCS Case which is because of the additional costs incurred due to carbon capture storage and transportation as well as the biogas fuel costs.

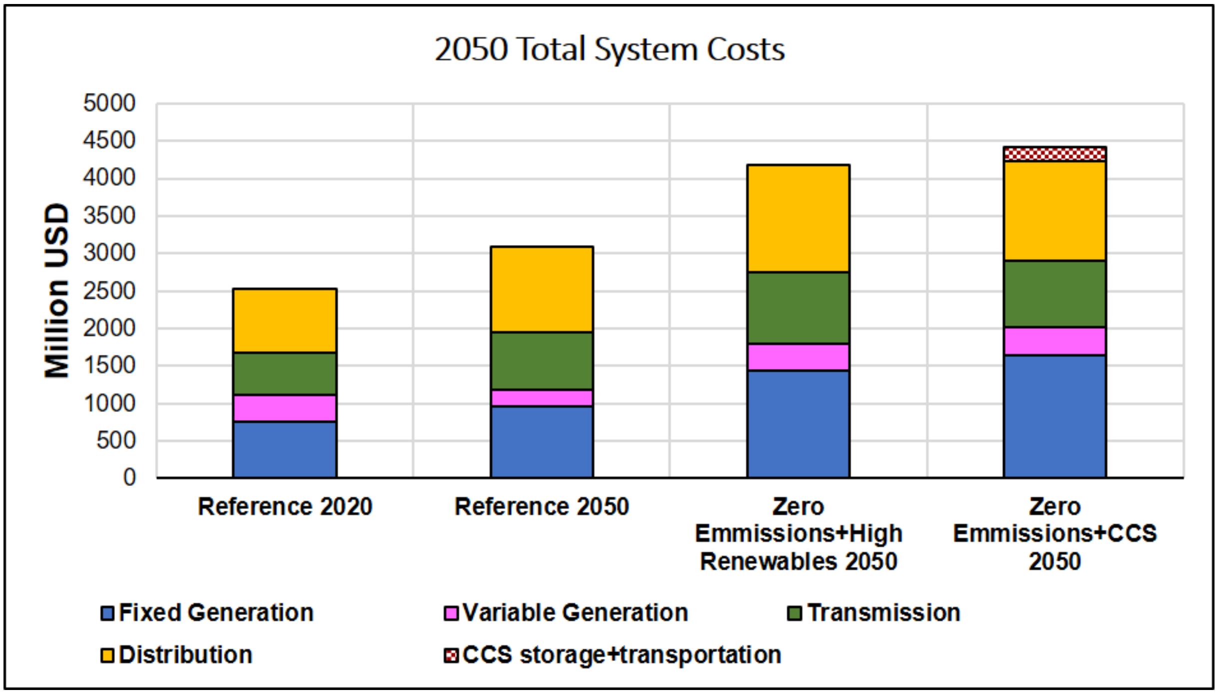

Figure 19. Breakdown of total system costs in all cases (2050)

Retail rate of electricity was calculated by dividing the total system costs by the total energy generation. As demonstrated in Fig. 20, there is an increasing trend of retail rate in the High Renewable case as well as the CCS case. The highest retail rate of electricity is seen in 2050, at $0.16/kWh in the CCS Case as compared to a lesser $0.15/kWh in the High Renewables Case. Interestingly, the Reference case shows a decline in the retail rate of electricity falling from $0.12/kWh in 2020 to $0.11/kWh in 2050. This is likely due to the rapidly increasing generation outpacing the rising system costs over the modeling period.

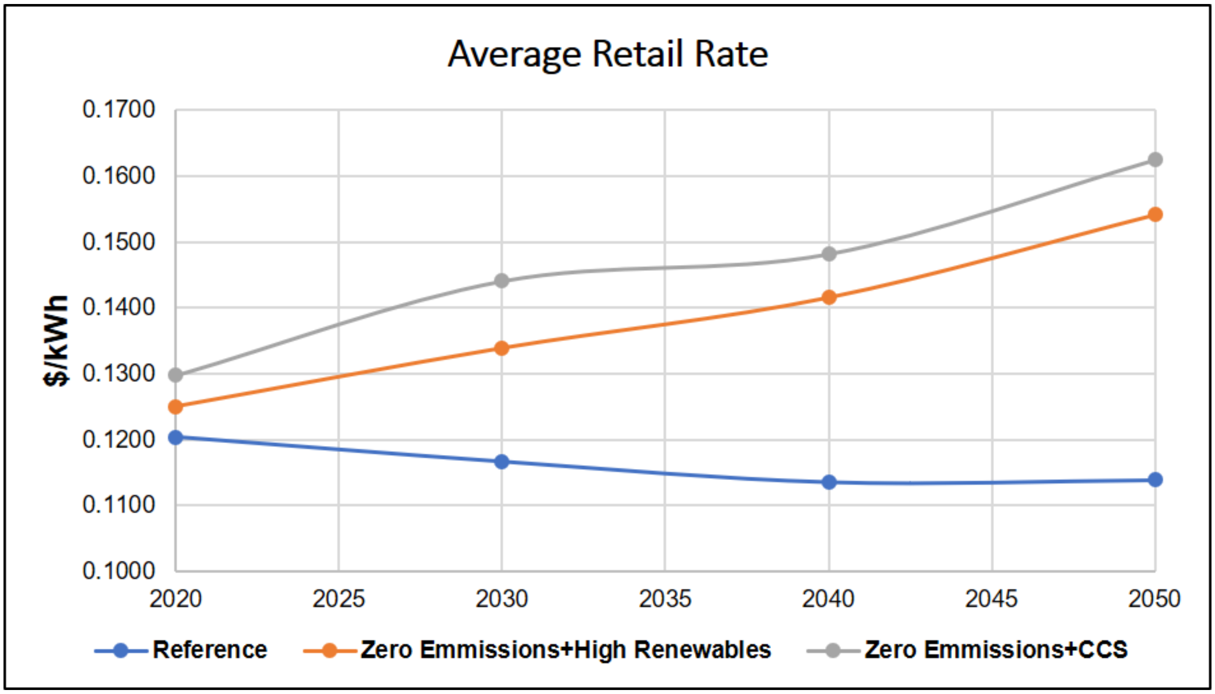

Figure 20. Retail rate of electricity in all cases from 2020 to 2050.

4.3 Carbon Intensity

The main research goal of this project was to achieve a zero-emissions target by the year 2050. Thereby, the reduction in carbon intensity was a key performance indicator of the scenarios. As expected, zero carbon emissions were achieved in both the High-Renewables case and the CCS case. Fig. 21 demonstrates the declining carbon emissions in the three cases from 2020 to 2050. The Reference case shows a decrease in emission intensity by almost 38% over this period. Although both the High Renewables case and the CCS case reach zero-emissions by 2050, the CCS case shows a potential to reach this target much earlier than 2050. This is caused by the non-linear decline in emission intensity for this scenario. In contrast, the High Renewables case displays an almost linear decline in emission intensity over 2020 to 2050.

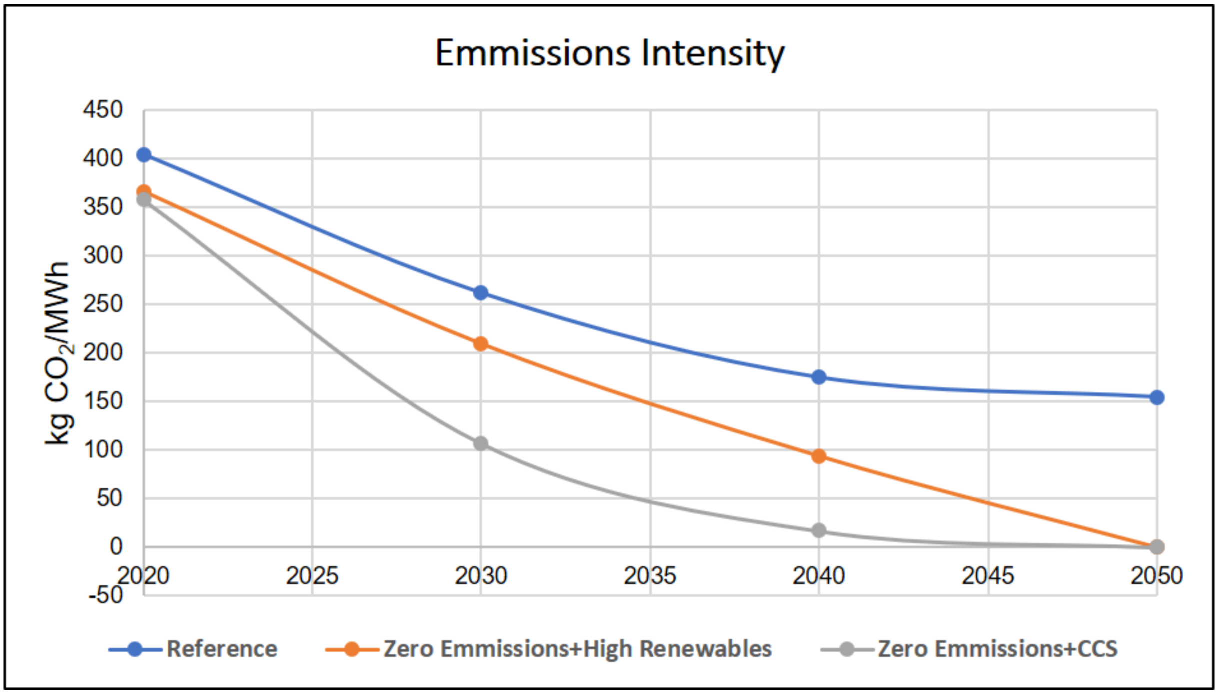

Figure 21. Carbon emissions intensity in all cases from 2020 to 2050

5. Discussion and Conclusions

PGE's climate stewardship and environmental initiatives are an integral part of making Oregon a carbon free state. With abundant renewable resource availability in the state, PGE has an advantage in making expeditious advancements in going above and beyond the Renewable Portfolio Standards set by the state. Our research goal of achieving zero-emissions by 2050 has been modeled in this study. We examined two different approaches to achieve this target, a High Renewables case and a CCS case.

- The CCS case is estimated to have the highest system costs at $4,411 million to achieve the zero-emissions target by 2050. This is followed by the High Renewable case at $4,186 million. The CCS case is $600 million more expensive than the High Renewable case.

- The annual cost of achieving a zero-emissions target is at least $1.1 billion more than the business-as-usual Reference case (Fig. 22). This is seen as the annual system cost difference between the Reference case 2050 and the High Renewables case 2050. Since this might be significantly expensive for the utility, it needs to be kept in perspective.

- The CCS case has the highest retail rate of electricity at $0.16/kWh in the year 2050. This is $0.0083/kWh higher than the High Renewables case which stands at $0.15/kWh. The retail rate in the High Renewables case is $0.04/kWh higher than the business-as-usual Reference case (Fig. 23).

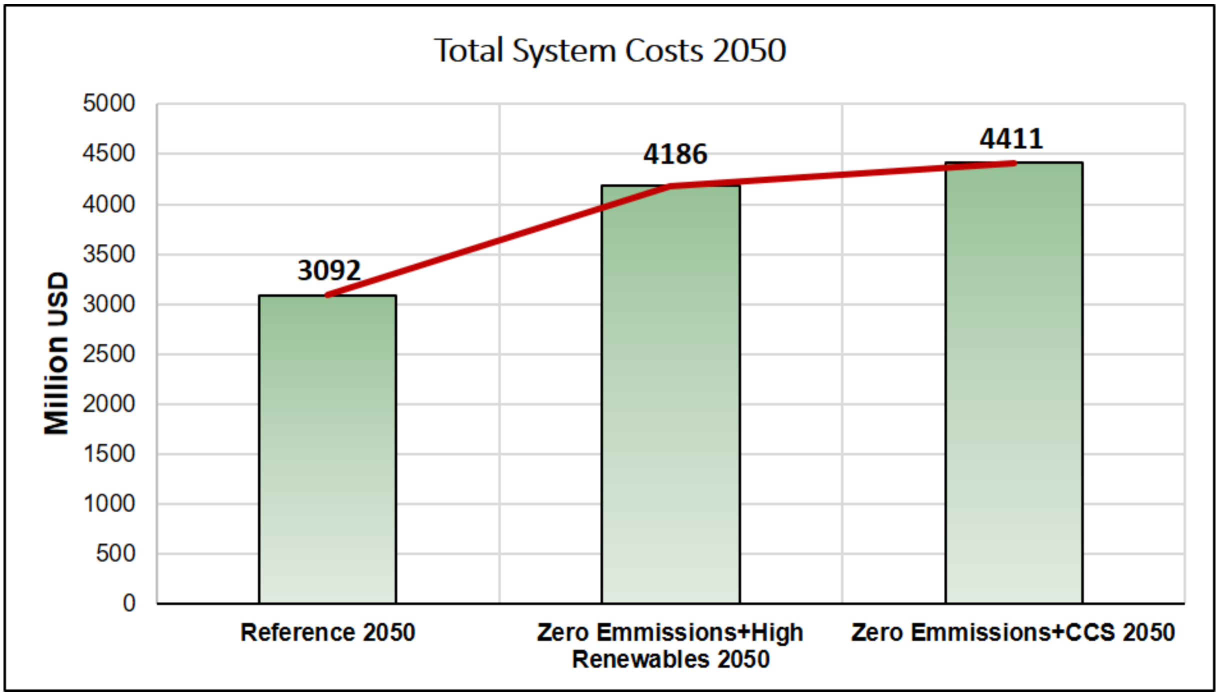

Figure 22. Change in total system costs across all cases (2050)

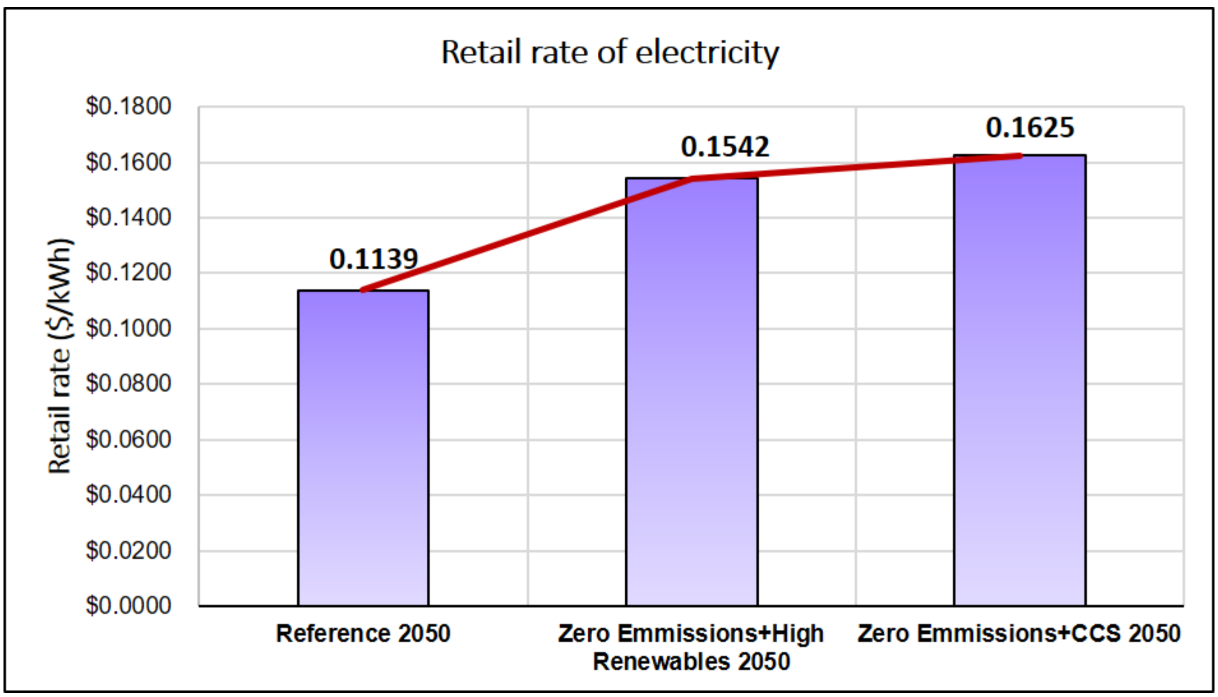

Figure 23. Change in retail price of electricity across all cases (2050)

In view of the above findings and analysis, we would like to recommend the High Renewable case as a more cost-effective and feasible approach to achieve zero-emissions by 2050. Although our study includes several aspects to building a safe and reliable planning system, it is not a comprehensive study. Additional factors that can be considered in future studies are battery storage additions, high electrification scenarios, energy efficiency and other types of demand side management.

6. Appendix

I. Key Performance Indicators for all years

Reference Case	2020	2030	2040	2050
Energy Sales (MWh)	21,040,958	22,772,227	24,846,819	27,437,876
Carbon-free share %	26%	35%	50%	55%
Renewable Share %	26%	35%	50%	55%
Emission intensity (kg CO2/MWh)	406	262	175	155
Retail rate of electricity ($/kWh)	0.12	0.12	0.11	0.11

High Renewables Case	2020	2030	2040	2050
Energy Sales (MWh)	21,044,670	23,327,511	27,714,216	30,708,016
Carbon-free share %	42%	60%	80%	85%
Renewable Share %	42%	60%	80%	85%
Emission intensity (kg CO2/MWh)	367	210	94	0
Retail rate of electricity ($/kWh)	0.13	0.13	0.14	0.15

Carbon Capture Sequestration Case	2020	2030	2040	2050
Energy Sales (MWh)	21,040,958	22,833,540	25,636,869	29,385,919
Carbon-free share %	46%	89%	99%	100%
Renewable Share %	37%	50%	65%	75%
Emission intensity (kg CO2/MWh)	358	107	17	0
Retail rate of electricity ($/kWh)	0.13	0.14	0.15	0.16

II. System costs for all years

Reference Case	2020	2030	2040	2050
Fixed Generation (mill$)	753	739	852	957
Variable Generation (mill$)	358	349	227	220
Distribution (mill$)	853	942	1041	1150
Transmission (mill$)	568	627	693	765
CCS Storage plus transportation	-	-	-	-
Total	2532	2657	2813	3092

High Renewables Case	2020	2030	2040	2050
Fixed Generation (mill$)	907	1019	1220	1431
Variable Generation (mill$)	304	341	276	363
Distribution (mill$)	853	1015	1207	1436
Transmission (mill$)	568	675	803	956
CCS Storage plus transportation	-	-	-	-
Total	2631	3050	3506	4186

Carbon Capture Sequestration Case	2020	2030	2040	2050
Fixed Generation (mill$)	965	1131	1347	1639
Variable Generation (mill$)	310	325	222	369
Distribution (mill$)	853	990	1149	1334
Transmission (mill$)	568	659	765	888
CCS Storage plus transportation	34	176	186	181
Total	2730	3281	3670	4411

III. Nameplate capacity for all years

Reference Case	2020	2030	2040	2050
Coal (MW)	938	296	0	0
CCGT (MW)	1386	2169	2295	3276
CT (MW)	1773	1928	2352	1744
CCGT+CCS (MW)	0	0	0	0
Wind (MW)	717	1247	1996	2396
Solar (MW)	2	329	867	1066
Hydro (MW)	646	575	709	890
Biomass (MW)	0	0	0	0
Total (MW)	5467	6543	8220	9373

High Renewables Case	2020	2030	2040	2050
Coal (MW)	938	296	0	0
CCGT (MW)	611	25	25	0
CT (MW)	1475	1475	1209	0
CCGT+CCS (MW)	0	0	0	0
Wind (MW)	1396	2266	3285	3402
Solar (MW)	308	765	1110	1844
Hydro (MW)	646	782	1134	1624
Biomass (MW)	1017	2452	3232	4701
Total (MW)	6395	8061	9995	11571

Carbon Capture Sequestration Case	2020	2030	2040	2050
Coal (MW)	938	296	0	0
CCGT (MW)	611	25	25	0
CT (MW)	1475	1475	1209	0
CCGT+CCS (MW)	900	2409	3213	4843
Wind (MW)	964	1687	2451	3227
Solar (MW)	501	638	902	1153
Hydro (MW)	855	902	1193	1321
Biomass (MW)	0	0	0	0
Total (MW)	6248	7432	8992	10544

IV. Electricity net generation for all years

Reference Case	2020	2030	2040	2050
Coal (%)	29.5%	7.3%	0.0%	0.0%
CCGT (%)	43.4%	56.8%	47.9%	45.1%
CT (%)	1.6%	1.2%	2.3%	0.1%
CCGT+CCS (%)	0.0%	0.0%	0.0%	0.0%
Wind (%)	14.8%	23.8%	34.9%	37.9%
Hydro (%)	10.7%	8.8%	10.0%	11.3%
Solar (%)	0.0%	2.1%	5.0%	5.5%
Biomass (%)	0.0%	0.0%	0.0%	0.0%

High Renewable Case	2020	2030	2040	2050
Coal (%)	30.9%	8.5%	0.0%	0.0%
CCGT (%)	18.8%	0.7%	0.5%	0.0%
CT (%)	8.7%	28.0%	19.1%	0.0%
CCGT+CCS (%)	0.0%	0.0%	0.0%	0.0%
Wind (%)	28.8%	42.2%	51.5%	48.1%
Hydro (%)	2.1%	4.7%	5.7%	8.6%
Solar (%)	10.7%	11.7%	14.3%	18.5%
Biomass (%)	0.0%	4.2%	8.9%	24.8%

Carbon Capture Sequestration Case	2020	2030	2040	2050
Coal (%)	33.6%	10.4%	0.0%	0.0%
CCGT (%)	20.4%	0.9%	0.6%	0.0%
CT (%)	0.3%	0.1%	0.0%	0.0%
CCGT+CCS (%)	8.2%	38.7%	36.6%	31.0%
Wind (%)	19.9%	32.1%	41.5%	47.7%
Hydro (%)	3.4%	4.0%	5.0%	5.6%
Solar (%)	14.2%	13.8%	16.3%	15.7%
Biomass (%)	0.0%	0.0%	0.0%	0.0%

V. Technology and Fuel costs for all years

Coal	2020	2030	2040	2050
CAPEX ($/kW)	3981	3869	3766	3639
Overnight Capital Cost ($/kW)	3660	3558	3463	3346
Fixed O&M ($/kW-yr)	33	33	33	33
Variable O&M ($/MWh)	5	5	5	5
Fuel Cost ($/MMBtu)	2	2	2	2
Annual Cost ($/kW)	304.37	296.92	290.03	281.52

CCGT	2020	2030	2040	2050
CAPEX ($/kW)	923	852	825	800
Overnight Capital Cost ($/kW)	903	833	807	782
Fixed O&M ($/kW-yr)	12	12	12	12
Variable O&M ($/MWh)	7	7	7	7
Fuel Cost ($/MMBtu)	2.99	3.06	2.18	2.18
Annual Cost ($/kW)	81.29	76.53	74.69	73.04

CT	2020	2030	2040	2050
CAPEX ($/kW)	1154	1154	1154	1154
Fixed O&M ($/kW-yr)	2.1	2.1	2.1	2.1
Variable O&M ($/MWh)	9.69	9.69	9.69	9.69
Fuel Cost ($/MMBtu)	2.99	3.06	2.18	2.18
Annual Cost ($/kW)	89.11	88.12	87.11	85.02

CCGT+CCS	2020	2030	2040	2050
CAPEX ($/kW)	2222	1987	1852	1726
Overnight Capital Cost ($/kW)	2174	1943	1811	1688
Fixed O&M ($/kW-yr)	34	34	34	34
Variable O&M ($/MWh)	7	7	7	7
Fuel Cost ($/MMBtu)	5.19	5.32	4.46	4.46
Annual Cost ($/kW)	189.49	173.75	164.70	156.29

Biomass	2020	2030	2040	2050
CAPEX ($/kW)	3908	3823	3669	3491
Overnight Capital Cost ($/kW)	3749	3667	3519	3349
Fixed O&M ($/kW-yr)	112	112	112	112
Variable O&M ($/MWh)	6	6	6	6
Fuel Cost ($/MMBtu)	3	3	3	3
Annual Cost ($/kW)	378.78	373.11	362.78	350.90

Wind	2020	2030	2040	2050
CAPEX ($/kW)	1528	1252	1116	978
Overnight Capital Cost ($/kW)	1494	1225	1092	957
Fixed O&M ($/kW-yr)	42	39	36	33
Variable O&M ($/MWh)	0	0	0	0
Annual Cost ($/kW)	144.71	122.75	110.71	98.54

Hydro	2020	2030	2040	2050
CAPEX ($/kW)	6370	6370	6370	6370
Overnight Capital Cost ($/kW)	6231	6231	6231	6231
Fixed O&M ($/kW-yr)	117	117	117	117
Variable O&M ($/MWh)	0	0	0	0
Annual Cost ($/kW)	544.18	544.18	544.18	544.18

Solar	2020	2030	2040	2050
CAPEX ($/kW)	1075	862	766	683
Overnight Capital Cost ($/kW)	1060	850	756	674
Fixed O&M ($/kW-yr)	13	10	9	8
Variable O&M ($/MWh)	0	0	0	0
Annual Cost ($/kW)	84.82	67.26	60.47	53.94

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