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An Integrated Resource Plan for Public Service Company of Colorado (PSCo)

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2050 Integrated Resource Plan

Executive Summary

An Integrated Resource Plan (IRP) is a tool used by load serving entities (LSEs) to plan how they will meet forecasted energy demand and system reliability requirements through a combination of supply-side and demand-side resources. The goal of an IRP is to identify the lowest cost option to meet future load while also adhering to policy requirements. For Public Service Company of Colorado's (PSCo) IRP process, a suite of generating resources, storage capacity, and demand-side management programs are all considered when developing a plan that meets state and utility regulatory requirements and environmental targets.

In 2016, PSCo's system peak demand was approximately 6,600 MW, while energy sales for the year totaled almost 32,000 GWh. PSCo currently operates a fossil fuel-heavy system, with coal accounting for over half of all energy generated in 2016, while the remaining half was a mix of mostly natural gas and wind. While PSCo currently has enough capacity between utility-owned facilities and PPAs to meet this load through 2021, projected load begins to surpass capacity in 2022, a trend which continues through 2050 as utility-owned generation facilities retire and PPAs expire. By 2050, PSCo's resource position is a deficit of almost 6,000 MW.

This report summarizes an IRP process that considered five future scenarios for the PSCo system. The first is a reference case where existing policy is unchanged, while the others present scenarios where carbon-free or renewable resources are further prioritized. Finally, the alternative scenarios also consider the impact of high electrification in the transportation and building sectors.

Reference	Carbon-Free	Carbon-Free with High Electrification	High RES	High RES with High Electrification
• "Business-as-usual" scenario. • 30% RES maintained through 2050. • After RES, meet capacity needs with lowest cost mix of solar, wind, and natural gas. • No new coal, nuclear, geothermal or hydro.	• Consistent with stated Xcel goal. • Interim targets of 80% and 90% emissions reductions for 2030 and 2040, respectively. • Meet capacity needs with lowest cost mix of solar, wind, storage, and natural gas with CCS.	• Transportation and building electrification leads to increased load growth. • Additional capacity needs through 2050 will be met by the same suite of resources as in 100% Carbon Free scenario	• Focus on renewables instead of carbon-free. • 90% RES in 2050. • Interim RES of 70% and 80% for 2030 and 2040, respectively. • After RES, meet capacity needs with lowest cost mix of solar, wind, storage, and natural gas.	• Transportation and building electrification leads to increased load growth. • Additional capacity needs through 2050 will be met by the same suite of resources as in High RES scenario.

Figure 1: Summary of the five IRP scenarios.

Table 1: Key performance indicators for all scenarios in 2050 and the reference case in 2020.

	2020 Reference	2050 Reference	2050 High RES	2050 Carbon-Free	2050 High RES w/ Elec.	2050 Carbon-Free w/ Elec.
Key Performance Indicators						
Nameplate Capacity (MW)	10,563	15,725	23,659	20,442	33,511	29,440
Energy Sales (GWh)	33,617	44,492	44,492	44,492	58,045	58,045
RES Share (%)	30.7%	58.1%	90.0%	83.4%	90.0%	81.8%
Carbon-Free Share (%)	30.7%	58.1%	90.0%	100.0%	90.0%	100.0%
Emissions (MMT)	18.24	8.32	2.01	0.00	2.37	0.00
Total Costs (M$)	4,047	5,750	5,851	6,143	7,642	8,288
Average Retail Rate ($/kWh)	$0.1204	$0.1292	$0.1315	$0.1381	$0.1317	$0.1428

Our results show that renewables made up almost 60% of energy sales by 2050 in the Reference scenario, while increasing this value to 90% in the High RES scenarios had only a marginal impact on average retail rates. At the same time, we found that removing the last portion of emissions from electricity generation and becoming 100% carbon-free by 2050 added approximately $645 million to system costs. The results indicate that the electrification of space and water heating and transportation had a dramatic impact on peak load and energy sales for PSCo's system. By 2050, seasonal peak had shifted from summer to winter, and the daily peak had shifted from afternoon to morning for most of the year.

Due to the high share of variable renewable resources and high curtailment levels projected in our results, we believe that demand-side management strategies (flexible loads, electric fuels, optimal storage use, etc.) will be increasingly important in reducing system costs and increasing capacity factors of renewable resources. The ability of PSCo to manage load and align consumption to periods of renewable generation can significantly reduce the need to build dispatchable resource capacity.

1. Introduction

1.1 Background

Title 40 of the Colorado Revised Statutes establishes the Colorado Public Utilities Commission ("Commission") and give it authority to regulate the public utilities within the state. The Commission requires electric utilities in the state to submit integrated resource plans (IRPs) that forecast customer demand, assess the need for additional resources, and propose cost-effective resource portfolios to meet reliability needs. Cost-effectiveness is defined by the Commission as "the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies". Colorado's IRP rules require an independent evaluator (determined by Commission staff, Office of Consumer Counsel and the filing Utility) reviews all documents and data used by the utility and submits an analysis to the Commission.

After a 45-day comment period the Commission is required to issue a written decision approving, conditioning, modifying or rejecting the utilities preferred cost-effective resource plan. Once the Commission has approved the IRP methodology and establishes the need for new resources, the utility can begin resource procurement. The IRPs submitted typically contain multiple resource acquisition scenarios proposed by the utility, often to reflect potential policy or cost determinants. While the Commission allows utilities to submit IRPs for a range of six to ten years from the date of filing, the purpose of this project is to develop a long-term IRP from 2019 through 2050 for Public Service Company of Colorado (PSCo), the largest electric utility in the state.

PSCo most recently submitted an IRP in the form of their 2016 Electric Resource Plan, which covers an eight-year resource acquisition period from 2016 through 2023. Beginning with the state of PSCo's system in 2019 according to the 2016 ERP, we present one Reference scenario and four Alternative scenarios in which PSCo meets its resource obligations through 2050. While any projection on this timescale will inevitably differ from reality, this process is a useful tool to evaluate future energy systems based on their technical and economic merits. This process also requires making assumptions about future technology performance and costs, potential policy actions, and economic indicators among other variables, and as a result we will be forthright about all assumptions that are included in this analysis. These planning considerations are outlined in detail in both the scenario outlines and methodology sections of this report.

1.2 Existing PSCo System

In their 2016 Electric Resource Plan (ERP), PSCo provides an eight-year projection of their load and resource balance and a resource acquisition plan to meet capacity needs through 2023, in addition to a general forecast of both peak demand and energy sales through 2050. In 2016, system peak demand was around 6,600 MW, while energy sales for the year totaled almost 32,000 GWh. PSCo operates a fossil fuel-heavy system, with coal accounting for over half of all energy generated in 2016 while the remaining half was mostly a mix of natural gas and wind (Figure 1.2-1). As a result, the carbon dioxide emissions intensity of PSCo's system (1,450 lbs/MWh) was 44% higher than the United States average (1,009 lbs/MWh) in 2016.

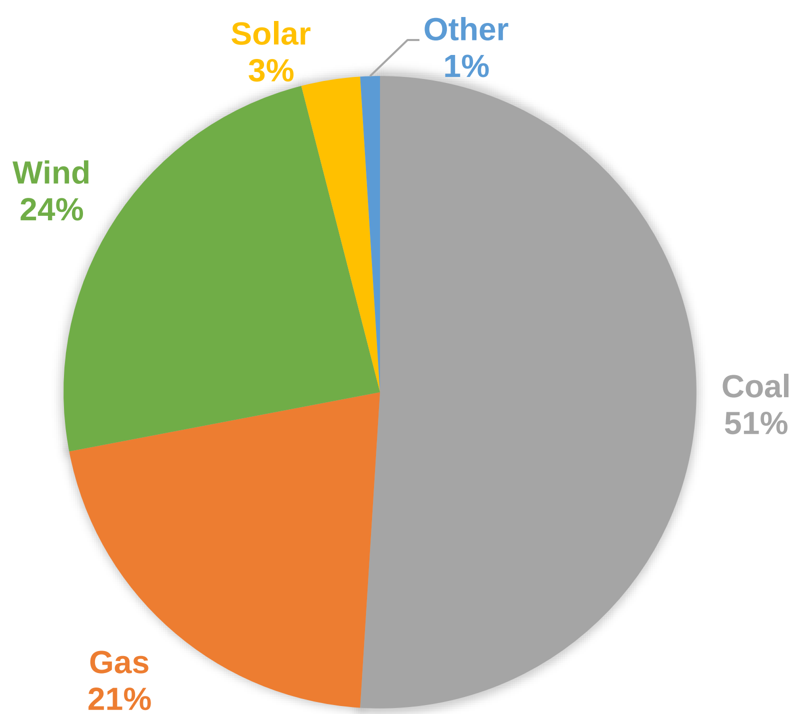

Figure 1.2: 2016 PSCo System Energy Mix

1.3 Policy & Regulatory Environment

In terms of state policies, Colorado's Renewable Energy Standard (RES) has the largest impact on PSCo's energy procurement plans. Enacted in 2004, the most recent update to the RES requires investor-owned utilities (IOUs) like PSCo to generate a minimum of 30% of its electricity from renewable resources, in addition to requiring that 3% come from distributed generation (DG). The RES requires electricity providers to obtain a minimum percentage of their retail electricity sales from a renewable energy portfolio including wind, hydroelectric, biomass and solar power from both utility-owned generating facilities and power purchase agreements (PPAs). In addition to the RES, the Colorado Clean Air-Clean Jobs Act (CACJA) signed into law in 2010 has impacted PSCo's energy system mix. The law requires annual reductions in NOx emissions and led to the shutdown of multiple coal-fired plants in Colorado, with the construction of new coal-fired generation unlikely.

On a federal level, PSCo assumes there will be no further extensions of the Production Tax Credit (PTC) for wind generation or the Investment Tax Credit (ITC) for solar generation in their 2016 Electric Resource Plan. Furthermore, they have responded to the uncertainty surrounding the Clean Power Plan by focusing their attention on state policy goals, with the hope that this action will put them in a good position to meet any future federal carbon requirements. For our reference case, we assume that this policy environment remains unchanged through 2050.

1.4 Resource Need Assessment

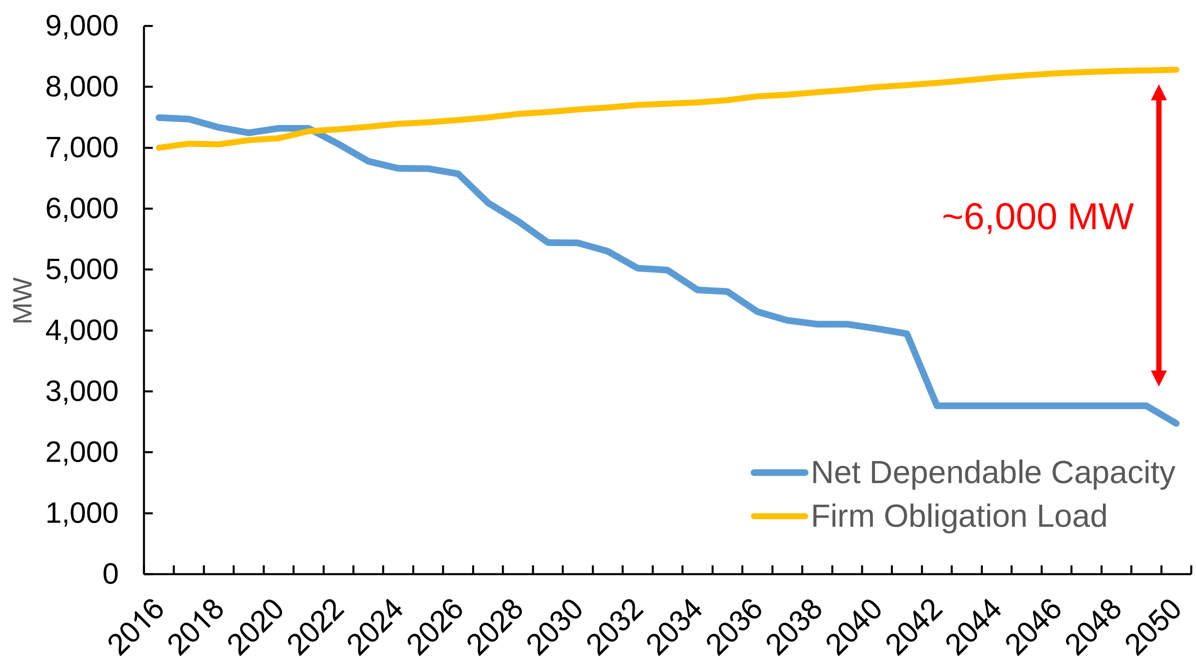

Figure 1.4: Net Dependable Capacity and Firm Obligation Load forecast from 2016 ERP

PSCo projects that system peak demand will grow from approximately 7,000 MW in 2016 to over 8,800 MW by 2050, while annual energy sales increase from approximately 30,000 MWh in 2015 to over 44,00 GWh by 2050. While PSCo currently has enough capacity between utility-owned facilities and PPAs to meet this load through 2021, projected load begins to surpass capacity in 2022, a trend which continues through 2050 as utility-owned generation facilities retire and PPAs expire. By 2050, PSCo's resource position is a deficit of almost 6,000 MW.

2. Scenario Descriptions

2.1 Overview

The objective of the IRP is to determine the optimal resource mix that will meet forecasted load for four ‘test’ years (2020, 2030, 2040, 2050) while meeting predefined operating requirements. All alternative scenarios described below will meet the following operating characteristics to ensure a robust, compliant and reliable system:

1. Reliability - generating capacity must meet planning reserve margins
2. RES compliance - renewable generation must meet state RES requirements
3. Operability - the system has to be operable in every hour of the year
4. Regulatory compliance - meet all current policy consideration

This report outlines four modelled cases that will deploy generation and storage resources to meet load in each of the test years: a reference case (RES Compliance), a 100% carbon free alternative case, a 100% carbon free alternative case including a high electrification scenario, a 90% renewables alternative case and a 90% renewables alternative case including a high electrification scenario. The details of these alternatives are outlined below.

Reference	Carbon-Free	Carbon-Free with High Electrification	High RES	High RES with High Electrification
• “Business-as-usual” scenario. • 30% RES maintained through 2050. • After RES, meet capacity needs with lowest cost mix of solar, wind, and natural gas. • No new coal, nuclear, geothermal or hydro.	• Consistent with stated Xcel goal. • Interim targets of 80% and 90% emissions reductions for 2030 and 2040, respectively. • Meet capacity needs with lowest cost mix of solar, wind, storage, and natural gas with CCS.	• Transportation and building electrification leads to increased load growth. • Additional capacity needs through 2050 will be met by the same suite of resources as in 100% Carbon Free scenario	• Focus on renewables instead of carbon-free. • 90% RES in 2050. • Interim RES of 70% and 80% for 2030 and 2040, respectively. • After RES, meet capacity needs with lowest cost mix of solar, wind, storage, and natural gas.	• Transportation and building electrification leads to increased load growth. • Additional capacity needs through 2050 will be met by the same suite of resources as in High RES scenario.

Figure 2.1: Summary of the five IRP scenarios.

2.2 Reference Scenario

The Reference scenario for our IRP is a “business as usual” scenario in which PSCo meets all future capacity needs at the lowest cost while adhering to current policy requirements, and forecasts for key variables are based on “base case” trends from PSCo’s 2016 Electric Resource Plan (ERP) wherever possible.

From our initial loads and resources analysis, we found PSCo's system to have a capacity deficit of roughly 6,00 MW in 2050. In this scenario, once scheduled generation resource additions from PSCo-owned facilities and power purchase agreements (PPAs) have been accounted for, additional capacity needs are met by deploying the lowest cost mix of wind and solar generation that satisfies the RES requirement of 30% of electricity sales. Following this, all remaining capacity needs are met by the lowest cost combination of renewables and natural gas-fired units and with generic cost and performance metrics based on current technology and natural gas price assumptions based on PSCo's base case natural gas price forecast.

Due to existing policy restrictions in Colorado, we assume for all scenarios that no new coal or nuclear plants will be built. In addition, we did not include hydro and geothermal resources as options for capacity expansion due to the physical limitations for both of those resources in Colorado.

2.3 Carbon-Free Scenario

Scenario 1A - Reference Load Growth

Alternative Scenario 1 presents a scenario in which the PSCo system is 100% carbon-free by 2050 and 80% carbon-free by 2030. Xcel Energy, PSCo's parent company, recently announced these targets for their entire service territory. Because this plan is not official state policy for Colorado, we are treating it as an alternative to the Reference Scenario.

Scenario 1A is based on PSCo projections from the 2016 ERP for load growth and scheduled/contracted resources from 2019 through 2050. However, once scheduled generation resource additions from PSCo-owned facilities and power purchase agreements (PPAs) have been accounted for, all additional capacity needs through 2050 are met by the lowest cost mix of carbon-free resources. In addition, there will be an emissions limit of 80% of 2005 PSCo emissions in 2030 and 90% in 2040. Emissions-free resources include variable renewable energy resources like wind and solar, in addition to fossil fuel generation with carbon capture and sequestration (CCS) and carbon-neutral biomass combustion generation. While geothermal and nuclear energy technically meet the carbon-free requirement, neither are present in PSCo's current or projected mix, and as a result we have chosen to exclude them from our model. Additional hydropower is also ruled out due to the physical constraints on building new hydro capacity of any meaningful amount in Colorado.

Scenario 1B: High Electrification

Scenario 1B presents a similar scenario to Scenario 1A in which the PSCo system is 100% carbon-free by 2050 and 80% carbon-free by 2030, but in this case a higher rate of load growth reflects high electrification. Additional capacity needs through 2050 are met by the same suite of carbon-free resources as in Scenario 1A. The policy and market conditions needed for high electrification include statewide mandates for EVs and electric heating technologies, a moratorium on sales of internal combustion engine (ICE) vehicles and building space and water heating after a certain year, or a carbon price that incentivizes the move towards electric end use technologies. The details of our high electrification scenario construction are explained further in section 4.1.

2.4 High RES Scenario

Scenario 2A: Reference Load Growth

The High RES scenario sets a target 90% renewable generation for the PSCo system in 2050, with carbon-emitting resources allowed to make up the remaining 10%. Because the current discussions surrounding aggressive state energy targets usually focus on declaring a target of 100% carbon-free versus 100% renewable, we believe a 90% renewable target is a less likely policy outcome than the Carbon-Free scenario. However, we believe there is value in comparing the relative costs of a 90% renewable and 100% carbon-free system, as it can illuminate the greatest challenges in technology and system balancing costs for each scenario.

Scenario 2A is based on PSCo projections from the 2016 ERP for load growth and scheduled/contracted resources from 2019 through 2050. However, once scheduled generation resource additions from PSCo-owned facilities and power purchase agreements (PPAs) have been accounted for, 90% of unmet energy needs in 2050 are met by the lowest cost mix of renewable resources. Following this, the remaining 10% is met by natural gas-fired combined-cycle and combustion turbine units and with generic cost and performance metrics based on current technology and natural gas price assumptions based on NREL's 2018 Annual Technology Baseline (ATB).

Scenario 2B: High Electrification

Scenario 2B presents a similar case to Scenario 2A in which the PSCo system is 90% renewables by 2050, but in this case a higher rate of load growth reflects high electrification. Additional capacity needs through 2050 are met by the same suite of resources as in Scenario 2A, although the additional annual loads and possible differences in load shape mean that the lowest cost mix of these resources may be different. Both this and the Carbon-Free with High Electrification scenario are based on the same electrification assumptions explained further in section 4.1.

3. Results

3.1 Summary

The table below shows key metrics for all of the scenarios modelled in our IRP process.

Table 3.1: Scenario summary for all scenarios in 2050 and Reference scenario in 2020.

	2020 Reference	2050 Reference	2050 High RES	2050 Carbon-Free	2050 High RES w/ Elec.	2050 Carbon-Free w/ Elec.
System Overview						
Nameplate Capacity (MW)	10,563	15,725	23,659	20,442	33,511	29,440
Dependable Capacity (MW)	7,618	8,269	8,269	8,269	13,897	13,896
Energy Sales (GWh)	33,617	44,492	44,492	44,492	58,045	58,045
RES Energy (GWh)	10,320	25,828	40,043	37,125	52,242	47,454
RES Share (%)	30.7%	58.1%	90.0%	83.4%	90.0%	81.8%
Carbon-Free Energy (GWh)	10,320	25,828	40,043	44,633	52,242	58,190
Carbon-Free Share (%)	30.7%	58.1%	90.0%	100.0%	90.0%	100.0%
Emissions (MMT)	18.24	8.32	2.01	0.00	2.37	0.00
Emissions Intensity (g CO_2/kWh)	542.45	186.96	45.27	0.00	40.91	0.00
Curtailment (GWh)	722	1,684	11,786	7,327	14,145	7,960
Curtailment Share (%)	2.1%	3.8%	20.9%	14.1%	19.5%	12.0%
System Costs						
Fixed Generation Costs (M$)	1,770	1,371	1,968	2,110	2,764	3,213
Variable Generation Costs (M$)	634	698	203	352	286	482
Transmission Costs (M$)	506	1,134	1,134	1,134	1,415	1,415
Distribution Costs (M$)	1,137	2,547	2,547	2,547	3,177	3,177
Total Costs (M$)	4,047	5,750	5,851	6,143	7,642	8,288
Average Retail Rate ($/kWh)	$0.1204	$0.1292	$0.1315	$0.1381	$0.1317	$0.1428
Nameplate Capacity (MW)						
Coal	2,292	536	536	0	536	0
Natural Gas	4,600	6,258	5,716	0	10,735	0
Natural Gas (CCS)	0	0	0	6,261	0	11,804
Wind	2,963	6,919	12,034	11,203	16,696	13,883
Solar	257	1,592	4,686	2,558	3,898	3,334
Hydro	55	23	23	23	23	23
Storage	396	396	664	396	1,624	396
Total	10,563	15,725	23,659	20,442	33,511	29,440
Net Generation Share						
Coal	54%	9%	3%	0%	3%	0%
Natural Gas	15%	33%	7%	0%	8%	0%
Natural Gas (CCS)	0%	0%	0%	17%	0%	18%
Wind	29%	51%	72%	72%	77%	71%
Solar	2%	7%	17%	10%	12%	10%
Hydro	1%	0%	0%	0%	0%	0%

3.2 System Capacity

3.2.1 Nameplate capacity

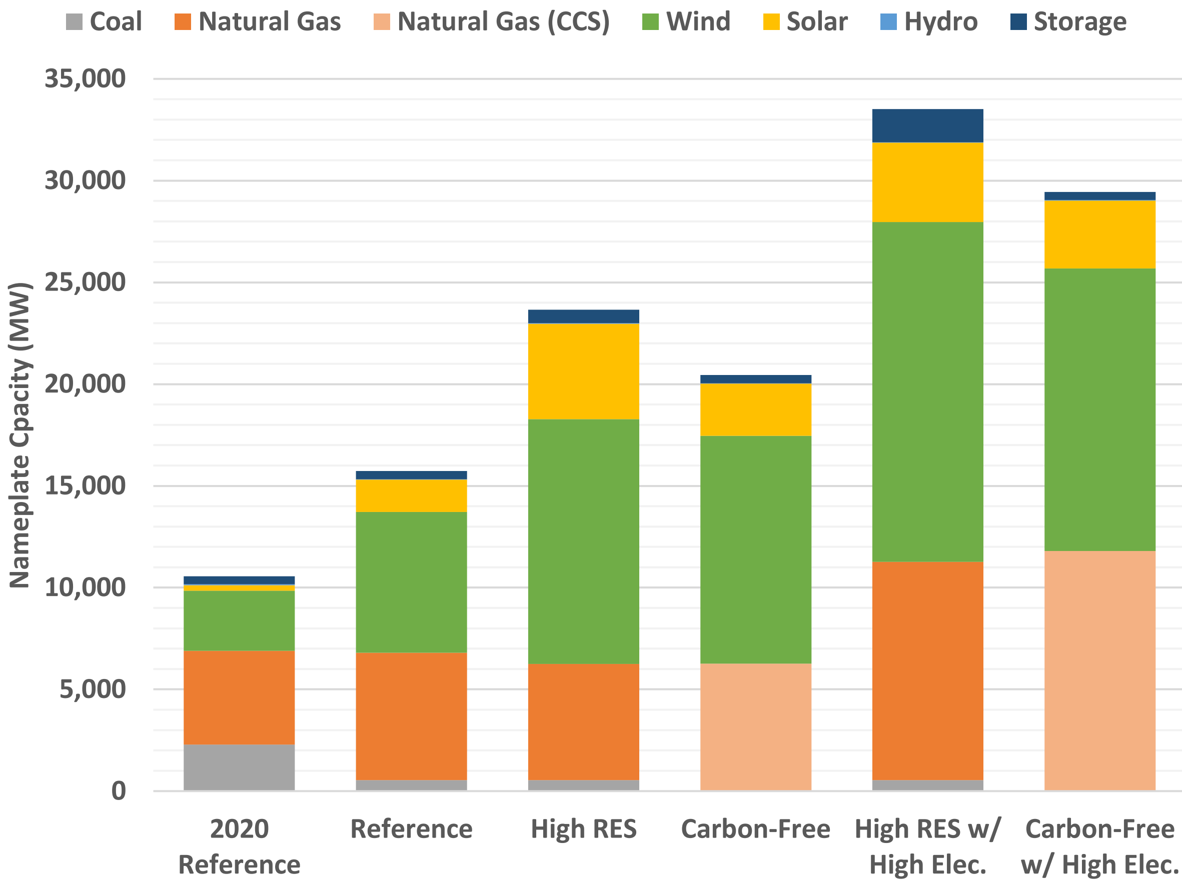

Figure 3.2-1: System nameplate capacity for all scenarios in 2050 and reference scenario in 2020.

The figure above displays the nameplate capacity for all scenarios in 2050 along with system capacity from 2020 in the Reference Case. The nameplate capacity, or rated capacity, is the intended full-load output for a traditional generating facility, or the output under optimal conditions for a variable renewable resource like wind or solar. In the Reference Case, wind and natural gas capacity grows faster than other resources, adding approximately 4,000 MW and 1,600 MW respectively between 2020 and 2050. With no emissions or generation constraints outside of the 30% RES standard, the low cost of wind, solar, and natural gas leads to no additional storage or natural gas with CCS capacity being built.

The High RES scenario requires that 90% of generation share comes from renewable resources which leads to over 9,000 MW of wind capacity being built by 2050, with a smaller increase in solar capacity. Natural gas capacity is also slightly lower than in the Reference Case. The installed nameplate capacity totals 23,650 MW in the High RES scenario. In order to reliably serve the added load from transportation electrification and space and water heating, the High RES with High Electrification has the highest nameplate capacity of all scenarios with 33,500 MW. Because load grows dramatically in this scenario, over 6,000 MW of natural gas capacity can be built while the

90% RES standard is still met in 2050. Unsurprisingly, high amounts of renewable capacity are built as well, with over 13,700 MW and 3,400 MW of wind and solar added, respectively. Finally, the High RES with High Electrification is the only scenario that sees a significant increase in storage resources, with around 1,200 MW added.

In the Carbon-Free scenario, the 100% emissions reduction target in 2050 leads to over 6,000 MW of natural gas with CCS being built by 2050, with smaller increases in wind and solar capacity than in the Reference Case. In the Carbon-Free with High Electrification scenario, total nameplate capacity increases to 29,440 MW, although this is still 4,000 MW less than total nameplate capacity for the High RES with High Electrification scenario. Meeting the increased load growth while maintaining compliance with 100% carbon free generation in 2050 requires an even greater deployment of natural gas with CCS capacity along with additional wind and solar.

3.2.2 Dependable Capacity

Planning reserves requirements mandate that PSCo has a 16.3% reserve margin of dependable capacity above the peak load for each year. Unlike nameplate capacity, dependable capacity refers to the amount of load a generating facility can reliably serve during the most restrictive time period. Colorado currently has a summer peaking system, although this could change depending on the amount of space heating load that is electrified given the high heating loads during winter. For traditional thermal plants, dependable capacity is close to nameplate capacity but accounts for outages or maintenance time that could reduce the amount of reliable amount. For variable renewable resources, dependable capacity is contingent on both the output of each individual resource and the resource penetration in the system, making it complex to calculate. For our analysis, we used a simplified calculation for renewables and storage that defines dependable capacity for these resources as a whole as the difference between peak load and the peak net load after renewables and storage. Dependable capacity meets or exceeds PSCo's planning reserves requirements in all scenarios. Scenarios with high renewable penetrations require a greater amount of wind and solar nameplate capacity, along with either natural gas or natural gas with CCS, to meet planning reserve requirements.

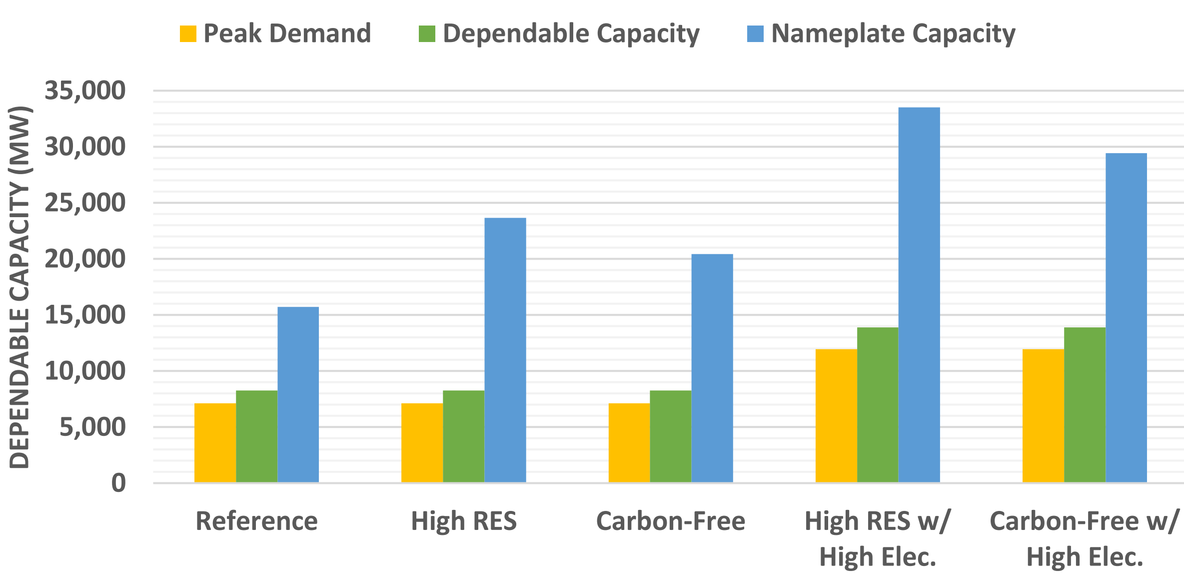

Figure 3.2-2: Capacity values for all scenarios in 2050.

3.3 Energy Generation & Sales

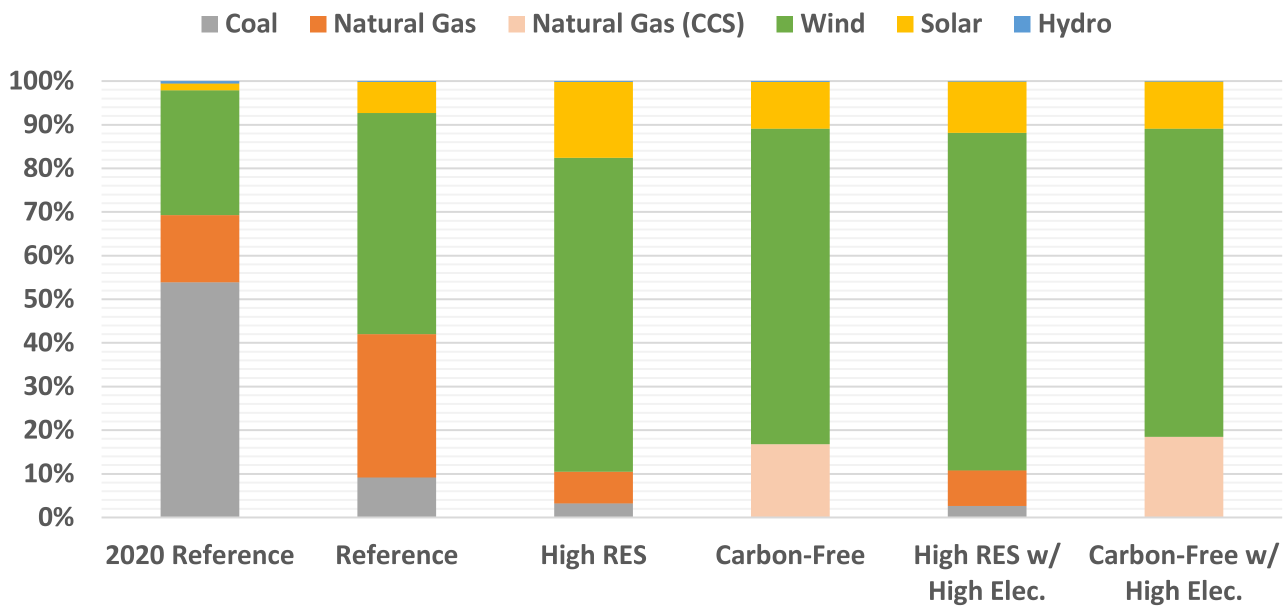

Figure 3.3-1: Net generation share by resource in 2050 for all scenarios and in 2020 for Reference Scenario.

Renewables make up a larger share of net generation than nameplate capacity in all of the alternative scenarios. The dispatch model prioritizes variable renewable production (wind, solar, and hydro) followed by available storage discharge during periods of high load and thermal generation to meet any remaining net load. Determining hourly resource dispatch is required to determine system costs, emissions, and operability. For the High RES scenarios, the dispatch model limits generation from non-renewable resources to 10% of energy sales in 2050. In the carbon-free scenarios, emissions requirements mean that only a certain amount of traditional thermal resources can be dispatched during the interim target years and non-emitting resources are allowed in 2050. As a result, natural gas with CCS becomes a viable generating resource in these scenarios.

Due to the variability of renewable resources, their energy generation can exceed load during in many hours of the year, leading to an involuntary need to store or curtail renewable energy generation. The high penetrations of renewables, in addition to the high cost of storage and limits to accurately modeling storage characteristics in our capacity expansion model, lead to curtailment accounting for a significant share of annual generation in some scenarios. Figure 3.3-2 below illustrates how often generation exceeds load in 2050 for High RES, the scenario with the highest percentage of curtailment.

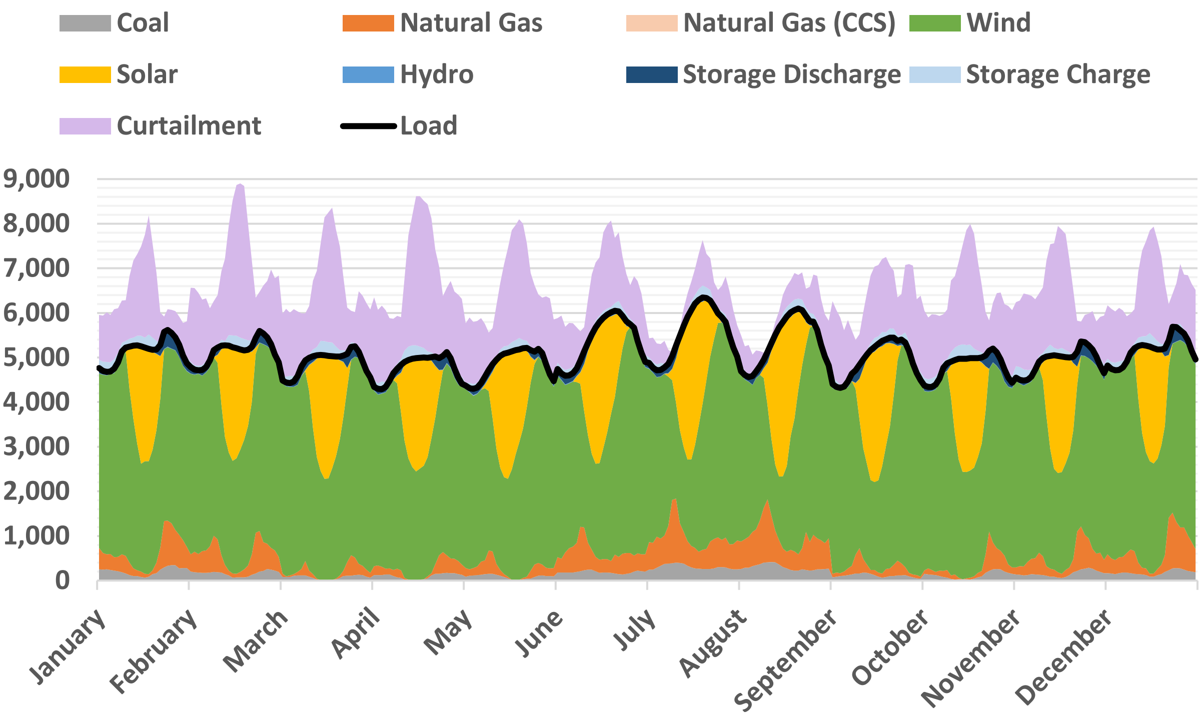

Figure 3.3-2: Month-hour average load and generation by source for 2050 in the High RES Scenario

3.4 System Costs

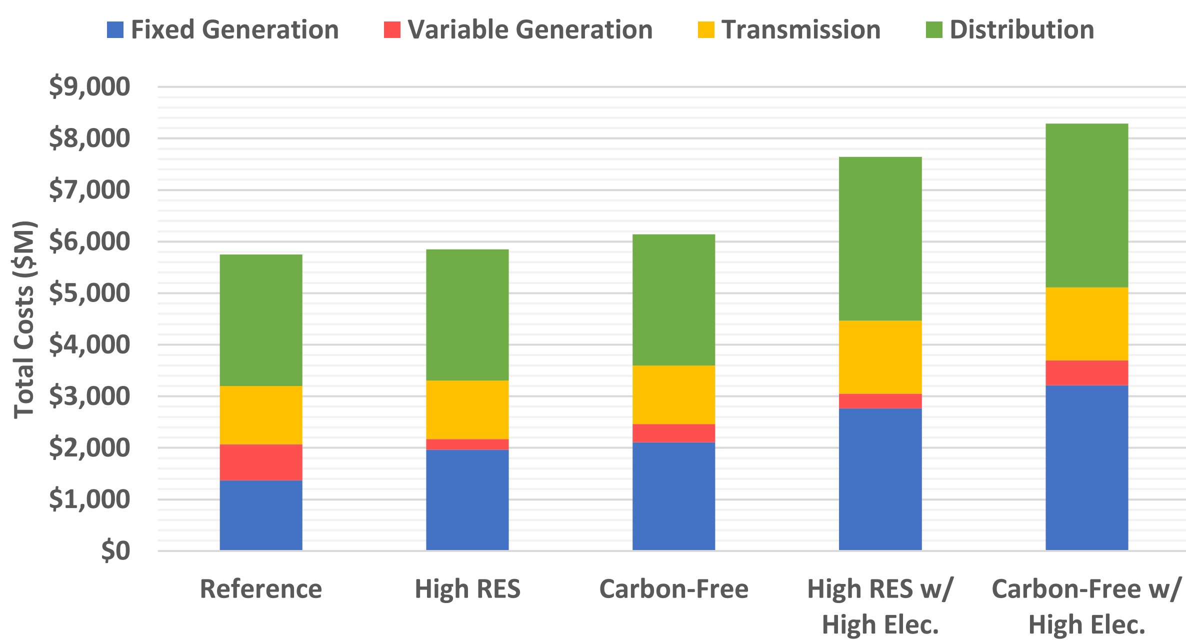

Figure 3.4: System costs in 2050 for all scenarios.

The figure above displays the final system costs for all scenarios in 2050 along with system costs from 2020 in the Reference Case. Because the High RES and Carbon-Free scenarios see an increase in renewable resources, fixed costs are a larger portion of generation costs than in the Reference Case, where more coal and natural gas-fired generation leads to higher variable costs due to fuel expenses. This trend is also true for the High Electrification scenarios.

Transmission and distribution costs (T&D) for 2020 were determined using the difference between our calculated generation rate and current Colorado retail rates. T&D costs were then assumed to increase at three times the compound annual growth rate for energy sales. This was chosen due to the significant addition of renewables (in all scenarios) reflecting the increased need for T&D upgrades in a renewable heavy system. Because energy sales are the same in 2050 for the Reference, High RES, and Carbon-Free cases, T&D costs are also the same in those scenarios. Finally, T&D costs are dramatically higher in the High Electrification scenarios as a result of the vast increase in energy sales.

Table 3.4: Average retail rates and rate impacts of all scenarios.

	Reference	High RES	Carbon-Free	High RES w/ Elec.	Carbon-Free w/ Elec.
Total Costs ($M)	5,750	5,851	6,143	7,642	8,288
Energy Sales (GWh)	44,492	44,492	44,492	58,045	58,045
Average Retail Rate ($/kWh)	**$0.1292**	**$0.1315**	**$0.1381**	**$0.1317**	**$0.1428**
Rate Impact (+/- %)	-	1.8%	6.8%	1.9%	10.5%

For all scenarios the average generation rate declines as more renewable resources are added to PSCo's generation mix due to project decrease in technology cost for all generating resources based on NREL Annual Technology Baseline (ATB) from 2018. For both High RES and Carbon-Free, retail rates are higher in both High Electrification scenarios. Finally, while average retail rates are higher for all alternative scenarios than the Reference Case in 2050, the two High RES scenarios have by far the smallest rate impact with an increase of less than two percent.

3.5 Emissions and Emissions Intensity

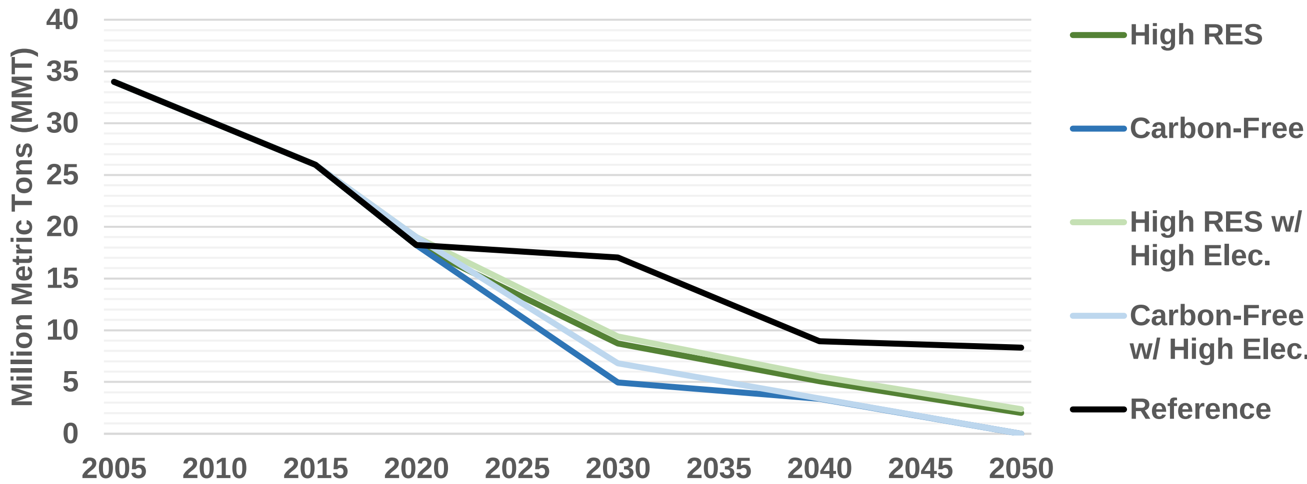

Figure 3.5-1: Electricity generation emissions by scenario.

Because PSCo currently uses 2005 as its baseline year for future emissions reductions targets, we have used this value to measure emissions reductions for all scenarios. The Reference case sees a decline of 76% by 2050, while the decline for the High RES and Carbon-Free scenarios are 94% and 100%, respectively. Notably, the High Electrification scenarios have higher emissions in most instances, although for the Carbon-Free scenarios their emissions reach the same level beginning in 2040. Finally, only the Carbon-Free scenarios meet's PSCo's stated target of 80% emissions reductions by 2030.The system emission intensity decreases faster than overall emissions for all scenarios due to forecasted load growth. Due to the dramatic increase in load growth in the High Electrification scenarios, the final emissions intensity for the High RES with High Electrification scenario is lower than that for the High RES with standard load growth, even though total emissions are higher. As expected, the final emissions intensity for both Carbon-Free scenarios is zero.

While the High Electrification scenarios have higher total emissions than their reference load growth alternative scenarios in most target years, the avoided emissions from transportation and heating are typically greater than this difference. This trend is illustrated in Figure 3.5-2.

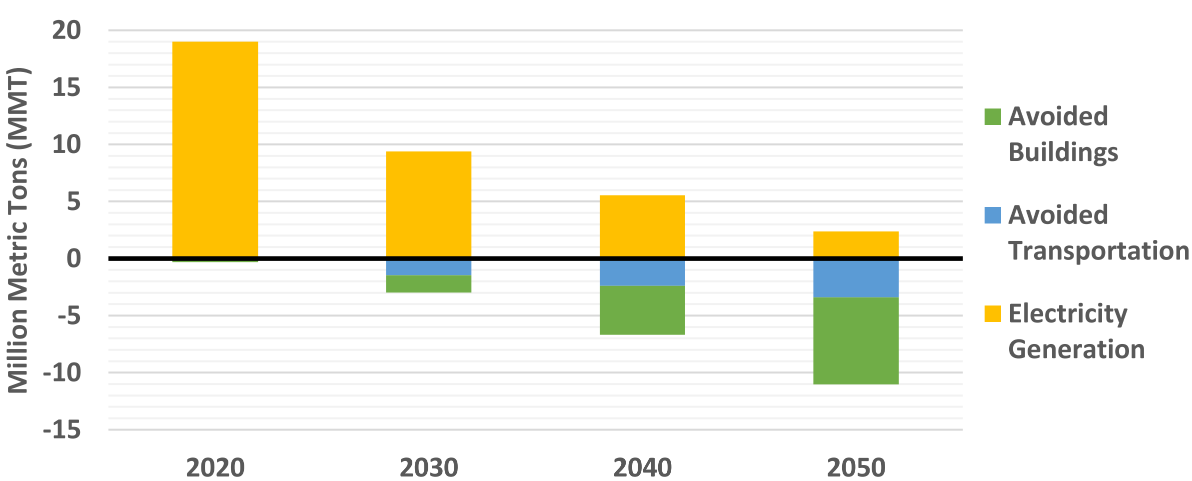

Figure 3.5-2: System emission for High RES with High Electrification.

4.0 Methodology

The figure below summarizes the IRP modeling process used for all scenarios referred to in this report.

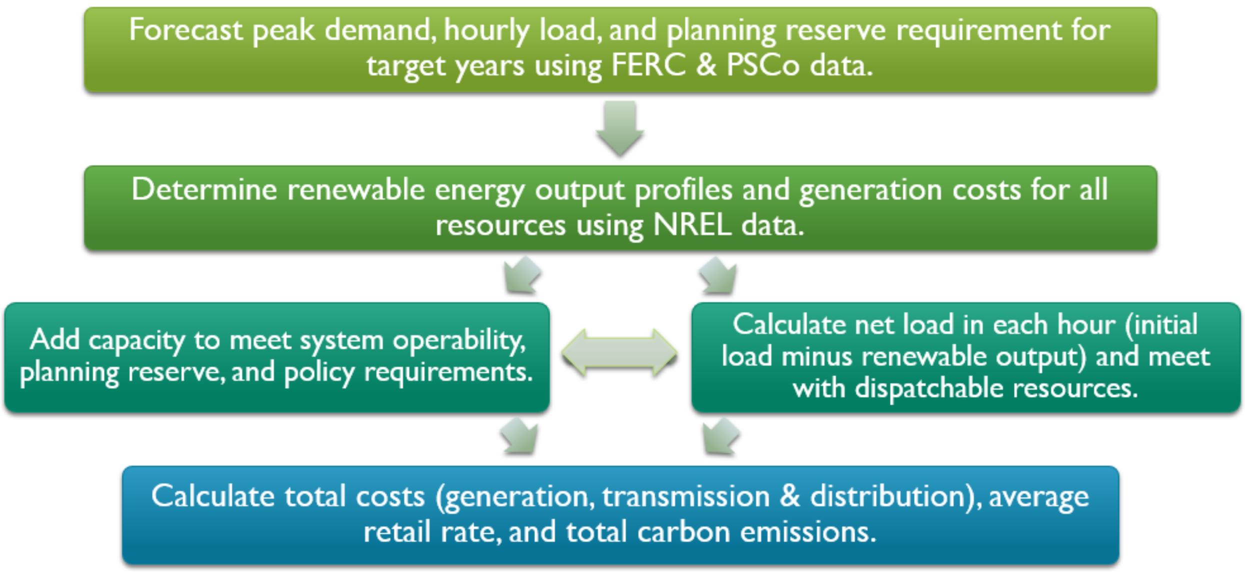

Figure 4.0: Overview of IRP modeling steps.

4.1 Load Forecast

4.1.1 Load Profile

The Reference Case, Alternative Case 1A, and Alternative Case 2A all use the load forecast provided by PSCo in their 2016 ERP for peak demand through 2050. The PSCo demand regression model calculates peak demand from monthly historical peak demand data by rate class combined with forecasted economic and demographic data and a normal weather forecast based on 30-year average of peak day weather.

Hourly demand for each of the test years is calculated by applying a system-wide load profile to the forecasted peak demand for that year. The load profile was derived from hourly demand data for PSCo's FERC-designated planning area. Although hourly demand for a handful of small, local utilities in Colorado is included in the dataset, PSCo's peak demand accounts for the majority of peak demand in the planning area. As a result, we assumed that the load profile for the planning area was an appropriate representation of PSCo's load profile.

4.1.2 High Electrification

Colorado House Bill 1314 (HB 1314) sets statewide goals to reduce 2050 greenhouse gas emissions by at least 90% of the levels of greenhouse gas emissions that existed in 2005. For Colorado to meet its climate goals the largest sources of state emissions including electricity generation, homes, buildings and transportation must be decarbonized. In 2010 these sectors accounted for approximately 75% of statewide greenhouse gas emissions. Achieving the goals of HB 1314 will require careful planning, stakeholder engagement, cost effective solutions and clear leadership from government and regulatory agencies.

The decarbonization of homes, buildings and transportation can be achieved by converting fossil fuel powered appliances to already available technologies powered by electricity. For example, electric vehicles (EVs) can provide clean transportation while high efficiency electric heat pumps can provide clean space and water heating. Shifting a significant portion of final energy demand to electricity will increase PSCo's system peak demand and annual energy consumption and will require additional generating resources. Figure 4.1.2 below illustrates the impact of high electrification on system load in 2050. As shown by the seasonal variation in load, the electrification of space heating will have an especially large impact on demand due to the high heating requirements during the winter in Colorado.

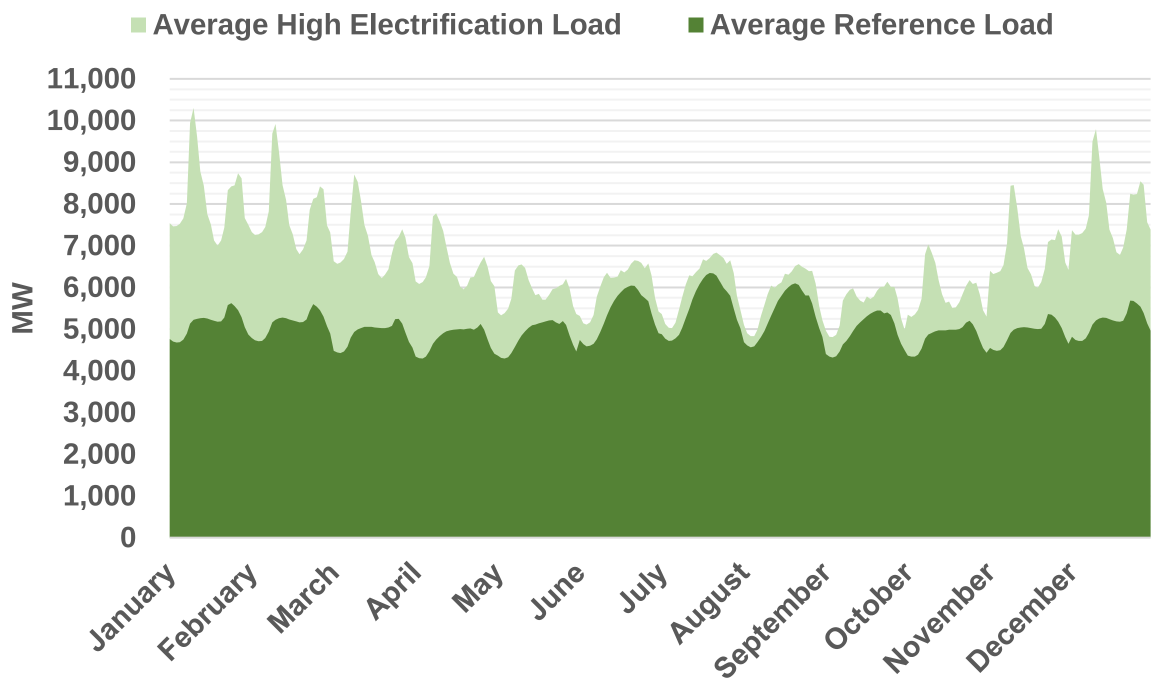

Figure 4.1.2: Month-hour average load for 2050 in both reference and high electrification load forecast scenarios.

Transportation:

For the purposes of this report, we included current state electric vehicles targets and anticipated future goals. The most important current state climate goal is to increase from approximately 13,000 EVs in Colorado at the end of 2017 to 940,000 by 2030. The electrification of transportation is expected to continue through to 2050 with an estimated 2,000,000 EVs on Colorado roads. Because PSCo serves approximately 54% of Colorado energy customers, we assumed that this proportion was true for EVs as well and that PSCo would serve the load of 1,094,563 EVs in 2050.

The table below provides the summary of PSCo estimates for EV adoption, travel and the associated annual energy consumption of the increasing EV fleet. The total EV load is allocated over the modelled test years using estimated weekday and weekend charging load shapes provided by Dr. Fritz Kahrl.

Table 4.1.2-1: EV adoption rates and performance assumptions.

Year	# of EVs	EV UEC (kWh/mi)	EV VMT (mi/EV/yr)	Annual EV Energy (MWh/yr)
2020	109,456	0.25	10,000	273,641
2030	547,282	0.20	10,000	1,094,563
2040	820,922	0.18	10,000	1,477,660
2050	1,094,563	0.15	10,000	1,641,845

Space and Water Heating:

The largest source of emissions in Colorado homes and buildings is generated from natural gas fueled space and water heating. In 2016, approximately 185,800 GWh were consumed in Colorado residential and commercial sectors of which approximately 101,700 GWh were used in PSCo's service territory (PSCo services approximately 54% of Colorado customers). Space and water heating accounted for a weighted average of approximately 58% of all commercial and residential PSCo building energy consumption. Total estimated space water and heating energy consumption is approximately 93,800 GWh in 2020 and is estimated to increase at a PSCo's load growth rate of 0.54%/year to 108,900 GWh in 2050.

Adoption rates of commercial and residential electrification were adapted from the NREL Electrification Futures Study (2017) beginning with a 10% conversion rate in 2020 and increasing to 65% conversion rate by 2050. Table 4.1.2-2 below provides the summary of PSCo estimates for space and water heating adoption.

Table 4.1.2-2: Space and water heating adoption rates and electrified loads.

Year	PSCo Total Residential/Commercial Energy Consumption (GWh)	% of Heating Load Electrified	Total Electrified Space & Water Heating Load (MWh)
2020	9,726	10%	261
2030	22,381	20%	1,201
2040	57,943	45%	6,994
2050	96,300	65%	16,791

The total commercial and residential electric heating load is allocated over the modelled test years using load shape data for space and water heating data gathered from Open EI.

4.1.3 Distributed Energy Resources (DERs)

Electricity grids across the nation are undergoing rapid transition; one factor attributed to this transition is the increased adoption of DERs by customers on the distribution system. Distributed Generation (DG) refers to small-scale, behind the meter (BTM) power resources that generate electricity. DG encompasses many from of generating technologies, but the most prominent and growing DG technology is distributed solar PV installed at customer locations. DG resources generate electricity close to end users compared with traditional, centrally located, generators. Effectively planning for and integrated DERs into electricity supplies and grids is both a technical and economic challenge for the electricity industry.

Solar*Rewards is an Xcel customers incentive program to incentivize solar installed on the distribution system at home or businesses. The program provides monthly payments in exchange for Renewable Energy Credits (RECs) for the energy produced by the solar system. The RECs are used by PSCo to achieve compliance under the RES program. The State's RES mandate requires 3 percent of retail sales from distributed generation (DG), including at least 1.5 percent from retail net-metered DG resources and up to 1.5 percent from wholesale DG resources (defined as resources ≤30 megawatts located in Colorado). For the purposes of this model, DG is treated as a load-side resource and DG production is subtracted off of peak demand.

4.1.4 Energy Efficiency and Demand Response

Energy efficiency (EE) refers to customer technologies and behaviors that reduce end-use energy consumption, while demand response (DR) refers to interruptible loads that can be shed to reduce peak capacity in times of need. EE provides load and demand reductions on a long-term and relatively constant basis, whereas DR provides short-term demand reductions. EE is most often focused on building efficiencies, such as lighting or mechanical retrofits, while DR has traditionally been implemented through the interruption of load for large industrial customers who are compensated for their participation. Along with DERs, both EE and DR reduce the customer load that PSCo is obligated to meet. As per PUC bill HB07-1037, EE and DR resources are subject to Commission involvement and therefore for the purposes of this project, we assumed that the CPUC-mandated annual targets for EE (65 MW) and DR (623 MW) were constant over the span of the IRP.

4.2 Capacity Expansion Model

Capacity expansion models are used to simulate generation and transmission capacity investment given assumptions about technology cost and performance, fuel prices, forecasted electricity demand and policy considerations. A spreadsheet-based capacity expansion model was used for this IRP. Inputs for the model included generating technology performance, fixed and variable costs, fuel costs, hourly load data, dependable capacity requirements, and policy requirements. Renewable energy output profiles were determined using data from NREL's System Advisor Model (SAM). Wind and solar output profiles for multiple locations across the state were averaged to develop a system-wide output profile for each resource. Given these inputs, the model used Solver, a Microsoft Excel optimization tool, to find the lowest cost system that would meet load, reliability requirements, and policy requirements.

4.3 Technology Costs, Fuel Prices and Emissions

Total annual production cost was determined by calculating the variable and fixed costs of each resource over the course of the year. Technology and fuel costs through 2050 were forecasted using the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).

Table 4.3: Generating technology assumptions overview.

Technology	NREL ATB Resource Category	Heat Rate (MMBtu/MWh)	Emissions Factor (kg CO2/MMBtu)	Operating Life (yr)
Coal	Coal-new-AvgCF - Mid	9.63	95.68	40
Natural Gas (CCGT)	Gas-CC-AvgCF - Mid	6.46	54.00	40
Natural Gas (CT)	Gas-CT-AvgCF - Mid	9.89	54.00	40
Natural Gas (CCGT with CCS)	Gas-CC-CCS-AvgCF - Mid	7.53	0.00	40
Natural Gas (CT with CCS)	**Calculated by adding CCS costs from CCGT to CT.*	10.00	0.00	40
Wind	TRG 3 - Low	N/A	0.00	25
Solar	Utility PV - Kansas City - Mid	N/A	0.00	30
Hydro	NPD 3	N/A	0.00	100
Storage	Low	N/A	0.00	15

The variable costs for thermal resources (Coal, Natural Gas, Natural Gas with CCS) were calculated based on the fuel type, heat rate, operating hours and operational and maintenance expenses. Fuel cost projections were also taken from the 2018 NREL ATB. As most post-combustion CCS is not entirely emissions-free, we assumed that approximately 10% of the gas consumed by CCS resources was comprised of recovered landfill biogas. The cost of recovered biogas from landfill was estimated to be twice the cost of traditional natural gas based on research conducted by the EPA and the World Petroleum Institute. The variable costs of renewable resource are limited to the variable operation and maintenance expenses of the technology. Annual fixed costs were calculated by adding fixed operations and maintenance costs ($/kW-yr) and the product of CAPEX ($/kW) and the capital recovery factor for each resource. Full tables displaying technology and fuel costs can be found in the appendix.

5.0 Conclusions

Colorado is a resource-rich state when it comes to renewables, especially wind. Renewables made up almost 60% of energy sales in 2050 in the reference scenario and increasing this value to 90% in the High RES scenarios had only a marginal impact on average retail rates. At the same time, we found that removing the last portion of emissions from electricity generation and becoming 100% carbon-free by 2050 added significant costs to the system. This was due to the reliance on natural gas with CCS to balance the system in each hour and meet reliability requirements. While it was not considered as a constraint in our model, it would be valuable to investigate the actual geological potential for carbon storage in Colorado, as by 2050 the state would have to accommodate approximately 10,000 GWh of CCS generation per year.

We believe that limitations on modeling storage effectively resulted in less storage capacity being added in the alternative scenarios than we would have expected. Only in the later target years of the High RES with High Electrification scenario was storage added in any significant quantity, and this seems to diverge from current projections of storage market growth.

On the demand side, we found that our high electrification projections had a dramatic impact on PSCo's system. By 2050, seasonal peak had shifted from summer to winter, and the daily peak had shifted from afternoon to morning for most of the year. The impacts of electrification of transportation and space/water heating have been assumed using static demand profiles and current estimates of performance improvement that may change as adoption of these technologies increases.

Due to the high share of variable renewable resources and high curtailment levels projected in our results, we believe that demand-side management strategies (flexible loads, electric fuels, optimal storage use, etc.) will be increasingly important in reducing system costs and increasing capacity factors of renewable resources. The ability of PSCo to manage load and align consumption to periods of renewable generation can significantly reduce the need to build dispatchable resource capacity.

While any prediction of how an electric utility's system will change over decades will invariably be wrong, our IRP attempted to consider some of the likely scenarios PSCo may face over the next 30 years. Further analysis into the assumptions and methodology of this model would yield more detailed output, but we believe our results provide an interesting starting point from which to begin discussing the paths available to PSCo.

Appendices

Appendix I: Nameplate Capacity for All Target Years

Nameplate Capacity (MW) - Reference Case				
Resource	2020	2030	2040	2050
Coal	2,292	2,142	1,158	536
CCGT	2,219	1,969	2,652	3,365
CT	2,381	2,238	2,558	2,893
CCGT with CCS	0	0	0	0
CT with CCS	0	0	0	0
Wind	2,963	3,923	7,209	6,919
Solar	257	1,102	1,553	1,592
Hydro	55	25	23	23
Storage	396	396	396	396
Total	10,563	11,795	15,548	15,725

Nameplate Capacity (MW) - High RES				
Resource	2020	2030	2040	2050
Coal	2,292	2,142	1,158	536
CCGT	2,219	2,410	2,410	1,727
CT	2,381	2,045	2,350	3,989
CCGT with CCS	0	0	0	0
CT with CCS	0	0	0	0
Wind	2,963	6,329	9,129	12,034
Solar	257	3,260	3,154	4,686
Hydro	55	25	23	23
Storage	396	396	396	664
Total	10,563	16,607	18,620	23,659

Nameplate Capacity (MW) – Carbon Free				
Resource	2020	2030	2040	2050
Coal	2,292	2,142	1,158	0
CCGT	2,219	1,969	1,969	0
CT	2,381	859	621	0
CCGT with CCS	0	0	583	583
CT with CCS	0	1,271	1,764	5,679
Wind	2,963	9,694	11,653	11,203
Solar	257	2,006	2,450	2,558
Hydro	55	25	23	23
Storage	396	396	396	396
Total	10,563	18,362	20,618	20,442

Nameplate Capacity (MW) - High RES with High Electrification				
Resource	2020	2030	2040	2050
Coal	2,292	2,142	1,158	536
CCGT	2,219	2,641	2,641	1,905
CT	2,381	2,254	5,243	8,830
CCGT with CCS	0	0	0	0
CT with CCS	0	0	0	0
Wind	2,963	8,454	11,937	16,696
Solar	424	1,600	2,885	3,898
Hydro	55	25	23	23
Storage	396	396	421	1,624
Total	10,730	17,512	24,309	33,511

Nameplate Capacity (MW) – Carbon-Free with High Electrification				
Resource	2020	2030	2040	2050
Coal	2,292	2,142	1,158	0
CCGT	2,219	1,969	1,969	0
CT	2,381	859	621	0
CCGT with CCS	0	0	0	0
CT with CCS	0	1,726	4,953	11,804
Wind	2,963	9,383	14,333	13,883
Solar	424	2,584	3,453	3,334
Hydro	55	25	23	23
Storage	396	396	396	396
Total	10,730	19,083	26,907	29,440

Appendix II: Electricity Net Generation for All Target Years

Resource	Net Generation – Reference Case							
	2020		2030		2040		2050	
	GWh	Share	GWh	Share	GWh	Share	GWh	Share
Coal	18,118	53.9%	16,639	44.1%	7,380	17.9%	4,079	9.2%
CCGT	4,432	13.2%	4,905	13.0%	6,112	14.8%	13,069	29.3%
CT	747	2.2%	1,025	2.7%	1,408	3.4%	1,557	3.5%
CCGT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
CT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Wind	9,608	28.6%	12,825	34.0%	23,136	56.2%	22,568	50.7%
Solar	519	1.5%	2,206	5.9%	3,076	7.5%	3,178	7.1%
Hydro	193	0.6%	87	0.2%	82	0.2%	82	0.2%
Total	33,617	100%	37,687	100%	41,194	100%	44,533	100%

Resource	Net Generation – High RES							
	2020		2030		2040		2050	
	GWh	Share	GWh	Share	GWh	Share	GWh	Share
Coal	18,118	53.9%	9,135	24.2%	4,608	11.2%	1,449	3.2%
CCGT	4,432	13.2%	897	2.4%	2,385	5.8%	1,946	4.4%
CT	747	2.2%	1,367	3.6%	1,365	3.3%	1,291	2.9%
CCGT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
CT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Wind	9,608	28.6%	20,123	53.3%	27,036	65.5%	32,187	72.0%
Solar	519	1.5%	6,170	16.3%	5,782	14.0%	7,774	17.4%
Hydro	193	0.6%	87	0.2%	82	0.2%	82	0.2%
Total	33,617	100%	37,779	100%	41,257	100%	44,730	100%

Resource	Net Generation – Carbon-Free							
	2020		2030		2040		2050	
	GWh	Share	GWh	Share	GWh	Share	GWh	Share
Coal	18,118	53.9%	5,208	13.8%	3,103	7.5%	0	0.0%
CCGT	4,432	13.2%	411	1.1%	1,462	3.5%	0	0.0%
CT	747	2.2%	1,081	2.9%	931	2.3%	0	0.0%
CCGT with CCS	0	0.0%	0	0.0%	28	0.1%	2,429	5.4%
CT with CCS	0	0.0%	1,150	3.0%	1,200	2.9%	5,078	11.4%
Wind	9,608	28.6%	26,382	69.7%	30,282	73.4%	32,261	72.3%
Solar	519	1.5%	3,506	9.3%	4,184	10.1%	4,782	10.7%
Hydro	193	0.6%	87	0.2%	82	0.2%	82	0.2%
Total	33,617	100%	37,825	100%	41,272	100%	44,633	100%

Resource	Net Generation – High RES with High Electrification							
	2020		2030		2040		2050	
	GWh	Share	GWh	Share	GWh	Share	GWh	Share
Coal	18,579	52.5%	9,564	22.6%	4,675	9.3%	1,536	2.6%
CCGT	5,414	15.3%	1,695	4.0%	3,559	7.1%	2,751	4.7%
CT	793	2.2%	1,488	3.5%	1,916	3.8%	2,029	3.5%
CCGT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
CT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Wind	9,582	27.1%	26,320	62.3%	34,629	69.0%	45,300	77.4%
Solar	848	2.4%	3,104	7.3%	5,306	10.6%	6,860	11.7%
Hydro	193	0.5%	87	0.2%	82	0.2%	82	0.1%
Total	35,409	100%	42,257	100%	50,167	100%	58,558	100%

Resource	Net Generation – Carbon-Free with High Electrification							
	2020		2030		2040		2050	
	GWh	Share	GWh	Share	GWh	Share	GWh	Share
Coal	18,579	52.5%	7,048	16.7%	3,002	6.0%	0	0.0%
CCGT	5,414	15.3%	883	2.1%	1,818	3.6%	0	0.0%
CT	793	2.2%	1,331	3.1%	1,045	2.1%	0	0.0%
CCGT with CCS	0	0.0%	0	0.0%	0	0.0%	0	0.0%
CT with CCS	0	0.0%	1,473	3.5%	1,752	3.5%	10,736	18.4%
Wind	9,582	27.1%	26,854	63.5%	36,803	73.2%	41,089	70.6%
Solar	848	2.4%	4,607	10.9%	5,755	11.5%	6,283	10.8%
Hydro	193	0.5%	87	0.2%	82	0.2%	82	0.1%
Total	35,409	100%	42,284	100%	50,257	100%	58,190	100%

Appendix III: Technology & Fuel Costs

Coal							
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)	Fuel Costs ($/MMBtu)
2020	$4,078.46	$489.85	$3,588.61	$32.53	$330.67	$4.67	$2.19
2030	$3,973.36	$477.23	$3,496.13	$32.53	$322.99	$4.67	$2.26
2040	$3,871.27	$464.96	$3,406.31	$32.53	$315.52	$4.67	$2.36
2050	$3,739.34	$449.12	$3,290.22	$32.53	$305.88	$4.67	$2.41

Natural Gas (CCGT)							
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)	Fuel Costs ($/MMBtu)
2020	$1,059.94	$34.36	$1,025.58	$10.39	$87.87	$2.72	$4.07
2030	$1,012.06	$32.81	$979.25	$10.39	$84.37	$2.72	$4.53
2040	$977.03	$31.67	$945.35	$10.39	$81.81	$2.72	$4.76
2050	$937.25	$30.39	$906.86	$10.39	$78.90	$2.72	$5.31

Natural Gas (CT)							
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)	Fuel Costs ($/MMBtu)
2020	$905.86	$29.37	$876.49	$12.02	$78.24	$7.03	$4.07
2030	$861.40	$27.93	$833.47	$12.02	$74.99	$7.03	$4.53
2040	$830.03	$26.91	$803.12	$12.02	$72.69	$7.03	$4.76
2050	$795.10	$25.78	$769.33	$12.02	$70.14	$7.03	$5.31

Natural Gas (CCGT with CCS)							
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)	Fuel Costs ($/MMBtu)
2020	$2,191.39	$71.04	$2,120.35	$33.06	$193.25	$7.05	$4.07
2030	$2,012.60	$65.25	$1,947.36	$33.06	$180.18	$7.05	$4.53
2040	$1,867.35	$60.54	$1,806.81	$33.06	$169.56	$7.05	$4.76
2050	$1,715.55	$55.62	$1,659.93	$33.06	$158.46	$7.05	$5.31

Natural Gas (CT with CCS)							
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)	Fuel Costs ($/MMBtu)
2020	$2,037.31	$66.05	$1,971.26	$34.69	$183.62	$11.36	$4.07
2030	$1,861.95	$60.36	$1,801.58	$34.69	$170.80	$11.36	$4.53
2040	$1,720.35	$55.77	$1,664.58	$34.69	$160.45	$11.36	$4.76
2050	$1,573.40	$51.01	$1,522.39	$34.69	$149.70	$11.36	$5.31

Wind						
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)
2020	$1,380.95	$44.77	$1,336.18	$48.01	$164.17	$0.00
2030	$754.64	$24.46	$730.18	$40.62	$104.10	$0.00
2040	$684.00	$22.17	$661.82	$36.93	$94.46	$0.00
2050	$638.23	$20.69	$617.53	$33.24	$86.92	$0.00

Solar						
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)
2020	$1,031.75	$20.60	$1,011.15	$8.09	$89.40	$0.00
2030	$826.50	$16.50	$810.00	$6.80	$71.94	$0.00
2040	$755.08	$15.08	$740.00	$6.24	$65.75	$0.00
2050	$673.45	$13.45	$660.00	$5.60	$58.68	$0.00

Hydro						
Year	CAPEX ($/kW)	Construction Financing Cost ($/kW)	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)
2020	$4,258.27	$138.05	$4,120.22	$120.23	$409.35	$0.00
2030	$4,258.27	$138.05	$4,120.22	$120.23	$409.35	$0.00
2040	$4,258.27	$138.05	$4,120.22	$120.23	$409.35	$0.00
2050	$4,258.27	$138.05	$4,120.22	$120.23	$409.35	$0.00

Storage				
Year	CAPEX ($/kW)	Fixed O&M ($/kW-yr)	Annual Fixed Cost ($/kW)	Variable O&M ($/MWh)
2020	$2,238.31	$7.87	$250.22	$2.34
2030	$1,046.26	$5.27	$118.55	$1.44
2040	$821.80	$2.66	$91.64	$0.53
2050	$776.14	$2.66	$86.70	$0.53