2016

ELECTRIC INTEGRATED RESOURCE PLAN

July 12, 2016

Colorado Springs Utilities

It's how we're all connected

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Forecasts and Assumptions

The forecasts and assumptions used in the preparation of this Electric Integrated Resource Plan and its associated scenarios were current as of May 2015. Section 11.0 of this document lists significant events that have happened subsequent to the beginning of technical analysis in June 2015.

Executive Summary

Colorado Springs Utilities' 2016 Electric Integrated Resource Plan (EIRP) is a long-term strategic plan used to guide resource acquisition, conservation and demand-side management (DSM) decisions to meet customer electric demand through the year 2034. The EIRP is required to be updated every five years by the Western Area Power Administration (Western) in order to qualify for federal hydropower purchases. Also, due to industry changes and the economy, Colorado Springs Utilities has updated the 2012 EIRP through a process which began in 2014.

The EIRP process combines technical analysis and public participation to ensure a low cost, reliable and environmentally conscious electric supply. The analysis examines our existing portfolio of resources and carefully evaluates expansions that include conventional supply-side resources, power purchases, renewable and Western resources. The objective of the EIRP process is to evaluate and manage all resource options in order to determine not just a least cost plan, but a balanced set of new resources based on the projected demand forecast, environmental considerations, renewable energy goals, and other input assumptions.

Utilities Board Direction for 2016 EIRP

In addition to considering changing demand, fuel prices, customer opinion and other elements commonly included in an EIRP, the Utilities Board directed the following items in August 2014:

(1) Investigate different renewable and DSM goals, including the Utilities Policy Advisory Committee (UPAC) Energy Vision recommendation, and use a reference case with 10 percent renewable energy and 6 percent DSM by 2020;
(2) Examine the impact of the EPA proposed carbon dioxide regulation, the Clean Power Plan (CPP);
(3) Explore possible timelines for decommissioning individual units and the entire Drake Power Plant;
(4) Explore the possibility of decommissioning the Birdsall Power Plant; and
(5) Include societal impacts in the intangible component of the analysis, but do not monetize them. The Utilities Board reiterated the decision not to monetize societal impacts in the study in June 2015.

Colorado Springs Utilities currently operates with roughly 100 megawatts (MW) of excess capacity and is forecasting low demand growth, so decisions around these items will primarily drive new resource acquisition.

To address the first directive, many different levels of DSM and renewable energy scenarios were considered and ultimately evaluated in portfolios. Scenario results show the cost of achieving different levels of renewable energy and the value of different levels of DSM. Renewable and DSM levels from low to high were all represented in the portfolios available for selection.

The most beneficial level of DSM was recommended by UPAC at 10 percent with a two percent bill impact spending cap, which had a benefit-to-cost ratio of 1.8. All levels of DSM had a benefit-to-cost ratio greater than 1, except the highest level at 15 percent by 2020. Additional renewable energy came at an incremental cost, but also added portfolio diversity and helped portfolios comply with the CPP.

The possible impact of the CPP was included by looking at both the potential cost and ability to comply with a given portfolio's resources. Each portfolio was modeled to meet a carbon dioxide (CO_2) mass cap based on the final rule and proposed Federal Plan available at the time of the EIRP. Model results showed what the cost would be under a CO_2 cap and if any new resources or expansion plan modifications would be needed. Portfolios that had more proactive compliance measures had the potential to score better given the lower risk of incurring higher costs later under the regulation. These results give Colorado Springs Utilities the ability to start planning for alternative resource acquisitions if necessary, or have the confidence that a given portfolio could comply cost-effectively.

Several portfolios required little or no modifications for the CPP, while others added more renewable energy and decommissioned coal units. The cost of Portfolio H was especially sensitive to the CPP. It was not very economical without the CPP, but one of the most economical options with the regulation.

Various Drake decommissioning timelines were considered with each unit and the entire plant being decommissioned in 6, 9, or 15 years and phased unit decommissioning at several key dates including 2018 for Drake 5. At that time additional sulfur-dioxide (SO2) and oxides of nitrogen (NOx) control equipment would be required. Scenarios which kept the units online for the duration of the study were also considered. The mid-term timing of nine years is an estimated date based on the potential for additional emission control requirements, namely additional NOx control.

Results were analyzed to see what, if any, would be the best economic conditions to decommission some or all three units, as well as to identify what the additional cost would be if it were not the most economical option. Among the 10 portfolios considered, three included the full Drake plant decommissioning. While still more costly than keeping the units online, the most economical option was a phased decommissioning schedule with Drake 5 in 2018, Drake 6 in 2023 and Drake 7 in 2029.

As a minimally used peaking resource, Birdsall Power Plant was also considered for decommissioning in 2018. Two portfolios ultimately included its decommissioning, one of which was the least-cost portfolio. However, that portfolio was not one of the highest scoring when considering risk and other intangibles such as diversity.

Societal benefits were included in the evaluation of each portfolio under intangibles, but were not monetized as directed by the Utilities Board. Drake decommissioning portfolios scored highest with this metric.

Public Involvement

Colorado Springs Utilities sought significant customer involvement and input in the 2016 EIRP. Public involvement helped to revise scenarios and define the ultimate selection of portfolios. A select group of volunteers made up a Customer Advisory Group (CAG) who acted as the objective voice of public input from a cross-section of the community. Public outreach also included four public meetings, customer newsletters, extensive news coverage, customer surveys, and social media to encourage an open decision-making process.

The CAG's comments were included in the portfolio creation, the technical analysis, in the weighted decision matrix for intangible criteria evaluation, and selection of the recommended portfolio. Small modular nuclear reactors, new coal with carbon-capture and sequestration, several scenarios and a 10th portfolio were added as a result of the public process.

EIRP Process

The EIRP process considers various evaluation criteria and recommends a portfolio of resources that provides a balanced and responsible low-cost plan. The EIRP meets reliability requirements, is fiscally sound and flexible, promotes environmental stewardship, and balances risk and cost. In the EIRP process, supply-side resource options and DSM resources are evaluated on an equitable basis and integrated in a comprehensive manner. The results are used for 10-year budgets and action plans.

The 2016 EIRP process includes the following steps:

- Assessment of generating resources and assumptions.
- Definition of scenario options combining multiple projections for high-mid-low load growth, renewable resources, DSM, potential environmental regulations, fuel and wholesale market prices, and decommissioning options for Birdsall and Drake Power Plants.
- Evaluation of scenarios and capacity expansion plans with the ABB System Optimizer capacity expansion model and ABB Planning and Risk model.
- Development of candidate portfolios from scenario capacity expansion results.
- Assessment of revenue requirement (cost) impacts of the portfolios using the corporate financial model; regulatory risk based on revenue requirement (cost) of EPA's CPP for each portfolio; financial risk evaluation of portfolios using stochastic analysis with the ABB Planning and Risk detailed, hourly model; and evaluation of portfolios using weighted decision analysis to include the impact of non-quantitative factors.
- Combination of cost, risk, non-quantitative, and public input considerations to arrive at a recommendation.

The ABB System Optimizer Model was used to analyze 85 scenarios and identified the mix of existing and future resources that result in the lowest cost to meet projected load. The capacity expansion plans resulting from the scenario runs were grouped into nine energy portfolios for evaluation. A 10th portfolio, J, was added based on public input, but not evaluated for all measures due to much a higher cost. These portfolios include ranges of assumptions for renewables, DSM, unit decommissioning and fuel switching. Evaluation results for each of the nine portfolios is in Table ES-1, higher scores are better out of a possible 100 for each metric.

Sensitivities to the weighting of each metric were also considered, including eliminating cost without the CPP. However, Portfolios D, E, and F were always the top scoring alternatives.

Table ES-1: Portfolio evaluation results

Metric		Measure	Weight	Portfolio A Score	Portfolio B Score	Portfolio C Score	Portfolio D Score	Portfolio E Score	Portfolio F Score	Portfolio G Score	Portfolio H Score	Portfolio I Score
Cost without Clean Power Plan		NPV of Revenue Requirement $Millions	40%	90	88	93	99	100	97	21	63	31
Cost with Clean Power Plan Best Estimate for Springs Utilities Pending State Plan		NPV of Revenue Requirement $Millions	25%	80	76	89	97	100	94	33	92	58
Financial Risk Uncertainty for Demand, Natural Gas Fuel Prices, and Electric Market Commodity Prices		95th Percentile NPV of Revenue Requirement $Millions	25%	90	88	88	97	100	94	29	53	22
Intangibles	Dispatchability Portfolio Diversity Societal Benefits Customer Resource Preference Development Risk Transmission Reliance	Weighted Decision Matrix Score	10%	48	16	57	70	20	58	77	99	100
Total Weighted Score				83	78	87	95	92	92	32	71	42
Rank				5	6	4	1	2	3	9	7	8

Preferred Portfolio and Three Options

Based on all factors including cost (with and without the EPA's CPP), financial risk and intangibles, Portfolio D scored the highest. It calls for:

- Running Drake Unit 5 on natural gas and using it primarily as a peaking unit beginning in 2018.
- Ten percent demand reduction through DSM goals with spending capped at two percent of the customer's bill by 2020.
- A 20 percent renewable energy goal with incremental spending capped at one percent of the customer's bill. Based on today's cost estimates this would be 80 megawatts of new solar power, by 2020.

At their final public meeting, the CAG reached a consensus to support Portfolio D with additional options to mothball Drake Unit 5 for up to three years starting in 2015 or 2016 (with the potential to restart it within the three years as a natural gas unit); or decommission Drake Unit 5 no later than Dec. 2017.

Approved Portfolio

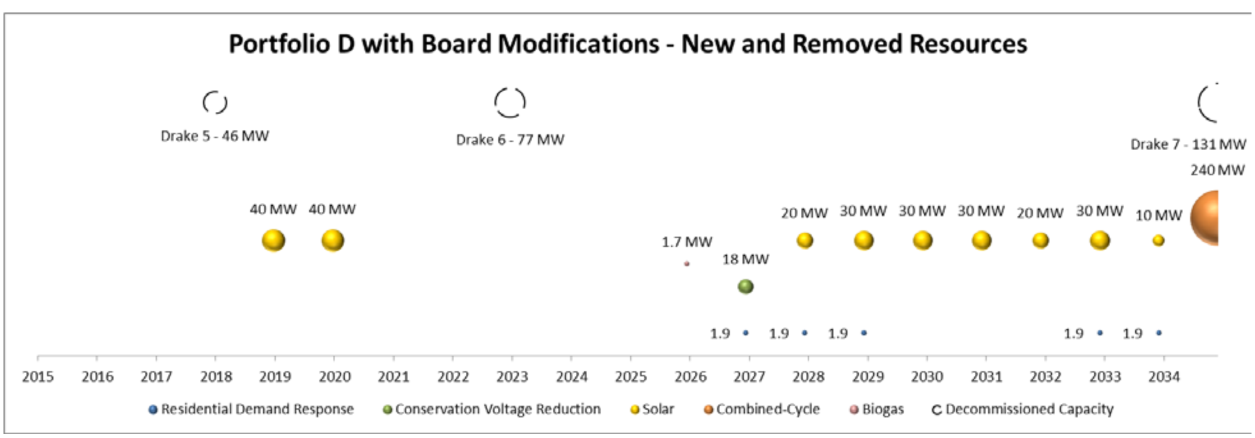
At the November 2015 Utilities Board meeting, the Board approved Portfolio D with modifications to decommission all three units at the Drake Power Plant no later than Dec. 31, 2035; and to increase the DSM goal to 12 percent by 2020 while setting the spending cap at two percent. In January 2016, the Board decided to decommission Drake 5 on or before Dec. 31, 2017. That capacity is not needed for at least 10 years and decommissioning results in a 10-year net present value savings of $2 million.

New resource acquisitions for 2015-2024 are described below. Figure ES-1 shows the full expansion plan for 2015 through 2035 assuming the CPP starts in 2022. Of significance in the first ten years is the addition of 40 MW of new solar photovoltaic (PV) in both 2019 and 2020. That amount of capacity and type of resource is based on current cost estimates for what could be achieved within the one percent incremental spending cap and could change at the time of procurement, if more or less capacity is achievable within that cap.

Modified Portfolio D Resources 2015-2024

By 2017	Decommissioning of Drake 5
2019	Solar – 40 MW
2020	Solar – 40 MW
2023	Potential Decommissioning of Drake 6 pending new NOx requirement and CPP

Figure ES-1: Modified Portfolio D expansion plan 2015-2035 assuming CPP in 2022



The Action Plan

The Action Plan identifies the steps to be taken to meet future demand and potential emerging industry and regulatory needs. Key steps included in the Action Plan are:

- Add planning for Drake Plant decommissioning no later than 2035 to the Utilities Board Strategic Planning Committee agenda.
- Continue to plan in a cost-effective manner that allows us to maintain a regional cost advantage for Colorado Springs Utilities.
- Decommission Drake 5 on or before Dec. 31, 2017.
    - Stop SO2 and NOx control projects for Drake 5.
    - Develop plan for Drake 5 decommissioning.
- Develop long-term operations and maintenance (O&M) spending, capital spending, and staffing strategies for Portfolio D generating units.
- Complete a solar integration study to investigate the impact of adding up to 80 MW additional solar capacity by 2020.
- Complete a solar rollout plan to determine how best to increase solar capacity, be it rooftop solar, community solar or utility scale solar.
- Evaluate transmission requirements and timing, especially as it relates to the decommissioning of the Drake plant units.
- Consider results of the DSM Potential Study and determine if any modifications to the portfolio would be needed.
- Investigate new rate structures and options:
    - Bill rider to support the UPAC Energy Vision
    - Net energy metering alternatives
    - Grid service support charges
- Continue the examination of potential new renewable resources and efficiency upgrades at existing power plants.
- Explore opportunities for marketing surplus generation.

The Action Plan will serve as Colorado Springs Utilities' guide for electric resource planning in the coming years.

Activities During the EIRP

During the EIRP, the Utilities Board approved the acquisition of 10 MW of solar power through power purchase agreement sited at Colorado Springs Utilities' Clear Spring Ranch site. This acquisition enabled Colorado Springs Utilities to take advantage of the expiring solar three-times renewable energy credit multiplier for Colorado Renewable Energy Standard (CO RES) compliance. Originally scheduled to expire on June 30, 2015, the state legislature passed an extension for the multiplier allowing units that are producing electricity prior to Dec. 31, 2016 to qualify as long as the project was under contract prior to Aug. 1, 2015. Colorado Springs Utilities was able to meet the contract deadline and the project is scheduled to be online by the end of 2016. This project will be the first 10 MW of the planned solar expansion as part of Portfolio D.

Also during the EIRP in the summer of 2015, 2.5 MW of community solar garden projects were completed and several Solar Renewable Energy Credit (SREC) acquisitions were completed to help meet the CO RES.

1.0 Introduction

Over the next 30 years, Colorado Springs Utilities will see a significant transformation of the electric utility industry as technology drives more cost effective renewable energy resources, distributed generation, DSM, energy storage and Smart Grid opportunities. At the same time, electric sales are declining and environmental regulations are expected to increase. These changes will drive the need to partner more closely with customers as we utilize both customer-owned and Utilities-owned resources to manage power supply and consumption.

This transition requires us to think differently about how we engineer our electric systems, how we design rates, how we train our employees and how we engage our customers in developing competitively priced solutions for meeting our future electric demands.

We understand and embrace the discipline and creativity needed to meet our goals of providing our customers with sustainable, reliable, competitively priced power while we move towards a vision of diverse, distributed and environmentally responsible power supplies.

Colorado Springs Utilities' 2015 EIRP is a long-term strategic plan used to guide resource acquisition, conservation and DSM decisions to meet customer electric demand through the year 2034. Updating the EIRP is prudent utility practice. It allows the public, policy makers and other stakeholders to engage in a process that will shape the future of the utility for many decades. Updated EIRPs are submitted to Western at least every five years so Colorado Springs Utilities can continue to qualify for federal hydropower purchases.

The EIRP process combines technical analysis and public participation to ensure low cost, reliable and environmentally conscious electric supply. The analysis examines our existing portfolio of resources and carefully evaluates expansions that include conventional supply-side resources, power purchases, renewable and DSM resources. The objective of the EIRP process is to evaluate and manage all resource options in order to determine not just the least cost plan, but a balanced set of new resources that meets reliability requirements, is fiscally sound, promotes environmental stewardship, is flexible, and balances risk and cost over a 20-year period.

Changes which have warranted an EIRP update include:

(1) Decreased solar photovoltaic costs and possible expiration of the wind Production Tax Credit (PTC);
(2) Revised load forecast that shows lower expected demand growth;
(3) Proposed EPA regulations to reduce carbon dioxide emissions;
(4) Refined costs for SO2 scrubbers on Drake Units 6 and 7 and Nixon 1;
(5) Customer opinion regarding Drake Power Plant resulting in a third-party study commissioned by the Utilities Board in 2013 to evaluate alternatives for Drake Plant's potential decommissioning;
(6) Decreased fuel prices, particularly natural gas price forecasts; and
(7) Revised resource costs.

1.1 Energy Vision

The EIRP includes an emphasis on environmental stewardship and an Energy Vision for Colorado Springs Utilities. The Energy Vision 2020's goal is to provide 20 percent of total electric energy through renewable sources, provide opportunities to achieve efficiencies with the goal of reducing average electric use by one percent each year through 2020, and maintain a 20 percent regional cost advantage.

The Energy Vision 2020, which goes beyond the minimum requirements, reflects the preference reported by some of Colorado Springs Utilities' customers for higher levels of renewable energy and energy efficiency as well as a trend toward higher renewable mandates by the Colorado General Assembly. Started in 2011, the Energy Vision is currently being implemented and has achieved each renewable energy target through 2014 and has achieved the DSM results shown in Table 1-1 below.

Table 1-1: Energy Vision DSM achievement 2011-2015

Year	**2011**	**2012**	**2013**	**2014**	**2015**
DSM MWh	22,745	40,328	54,114	36,903	*29,617*
DSM %	0.50%	0.89%	1.19%	0.83%	*0.66%*
DSM % Cumulative	0.50%	1.39%	2.57%	3.40%	*4.06%*

In April 2014, the UPAC completed an assignment to review the Energy Vision and recommended the following:

> By 2020:
> *Colorado Springs Utilities will provide 20 percent of its total electric energy through renewable sources with one percent from distributed generation sources. Renewable energy goals will be achieved with a maximum bill impact of 1 percent.*
>
> *Colorado Springs Utilities will help customers reduce their electric energy use by 10 percent and reduce electric demand by 12 percent. Reduction goals will be achieved with a maximum bill impact of two percent.*

Whether to adopt this recommendation, keep the current Energy Vision or consider something else was a key question for the 2016 EIRP.

1.2 Utilities Board Direction for 2016 EIRP

Considering the changes that have occurred in the community since the last EIRP and the alternative studies that have taken place in the interim, the Utilities Board initiated the 2016 EIRP and in August 2014 directed the following items be part of the study:

(1) Investigate different renewable and DSM goals, including the UPAC Energy Vision recommendation, and use a reference case with 10 percent renewable energy and 6 percent DSM by 2020;
(2) Examine the impact of the EPA proposed carbon dioxide regulation, the CPP;
(3) Explore possible timelines for decommissioning the Drake Power Plant;
(4) Explore the possibility of decommissioning the Birdsall Power Plant; and
(5) Include societal impacts in the intangible component of the analysis, but do not monetize them. The Utilities Board reiterated the decision not to monetize societal impacts in the study in June 2015.

Colorado Springs Utilities currently operates with roughly 100 MW of excess capacity and is forecasting low demand growth, so decisions around these items will primarily drive any new resource acquisition.

1.3 EIRP Process

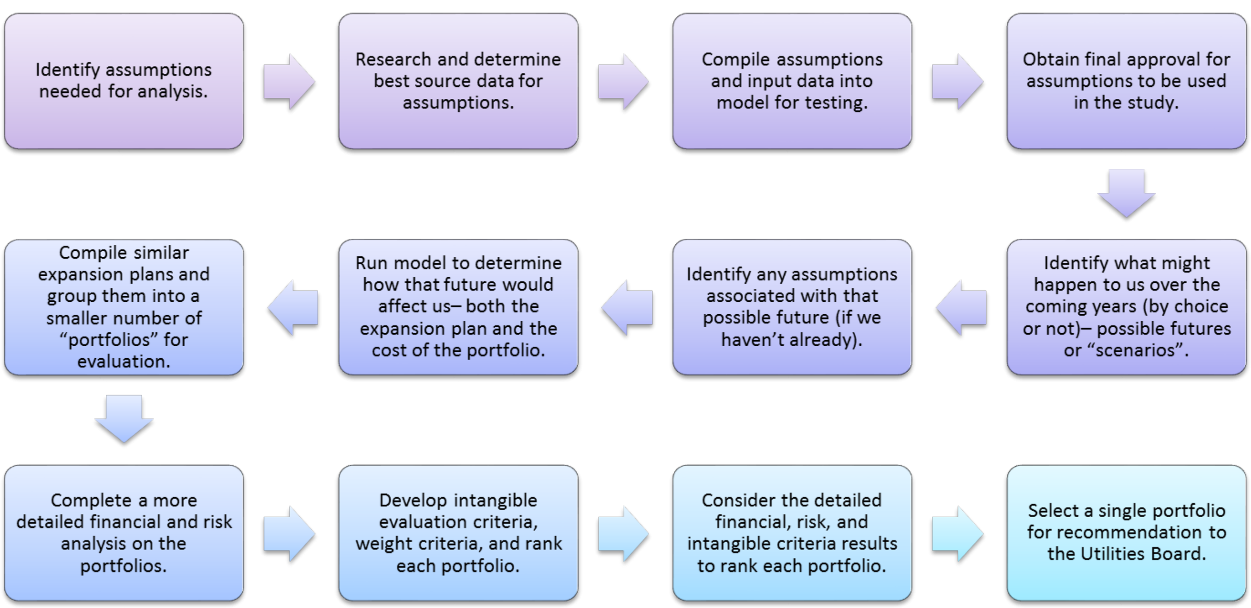
While each EIRP is different, the same basic process is followed to gather data on the existing system, develop a range of possible future conditions to consider, develop candidate portfolios, and select a final portfolio with customer and stakeholder input throughout. Figure 1-1 shows a map of steps to complete the EIRP.

The process begins with a wide scope of possibilities which, because of the volume, are screened at a higher level. Even with a high level screening, it still is nearly impossible to evaluate every single permutation or possibility for the future. Scenario modeling is intended to capture more likely possibilities and is informed by input from the public to ensure staff is considering aspects most important to our customers. Scenarios define conditions in the future and the result of modeling is a set of resources that would be least cost in that future condition (for example, high gas prices). Both internal and external factors are considered, that is policy changes that might be driven by Colorado Springs Utilities and probable events such as technological breakthroughs and regulations triggered outside of Colorado Springs Utilities.

Portfolios are then developed from the results of scenario modeling. The scenario modeling produces many different potential configurations of resources for the future. Where similar results exist, they are combined into a single portfolio. The goal is to reduce the number of potential resource portfolios into a smaller number of distinct options that can be analyzed in more detail and present a high likelihood of being implemented.

Once there are a smaller number of portfolios to consider, an evaluation process begins to select one. While cost is a key consideration, the evaluation process also considers risk and other intangible criteria that might make one portfolio more preferable than another. The objective is to recommend a portfolio of resources that provides a balanced and responsible plan, which meets reliability requirements, is fiscally sound, promotes environmental stewardship, is flexible, balances risk and cost, and reflects the values of our citizen owners.

Figure 1-1: EIRP Process steps



2.0 Existing System Overview

The City of Colorado Springs is a home rule municipal corporation located in the south central Front Range of Colorado. Key sectors of the City's economy and the surrounding area include service industries, retail businesses, construction industries, military installations, the high technology industry and tourism. The City owns and operates Colorado Springs Utilities as an enterprise under Colorado Constitution and City Charter provisions. The Charter states that Colorado Springs Utilities' funds are to be kept separate from all other City funds, and that Colorado Springs Utilities' net earnings are to be appropriated solely for the operations of Colorado Springs Utilities.

Figure 2-1: City of Colorado Springs and local Pikes Peak

Colorado Springs Utilities is a four-service utility providing electricity, natural gas, water, and wastewater treatment. Colorado Springs Utilities takes advantage of opportunities among our four services to reduce costs borne by customers. For example, the Tesla hydroelectric unit was built and operates at the outlet of the Stanley Canyon tunnel which conveys water from Rampart Reservoir. Once the water has been through Tesla it goes to the Pine Valley and McCullough Water Treatment Plants. In a similar way, the Cascade hydroelectric unit generates electricity using water that flows through a water service pipeline.

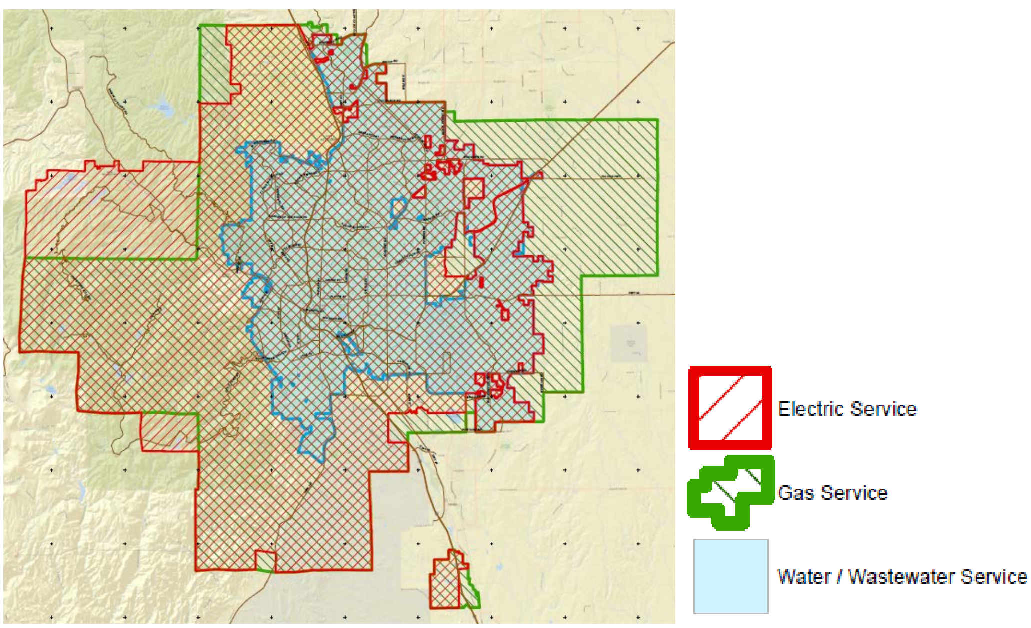
2.1 Electric Service Area and Load

The electric system provides retail service to Colorado Springs, Manitou Springs and portions of the City of Fountain, and delivers special contract power to the United States Air Force Academy (USAFA), Peterson Air Force Base, Fort Carson, and Cheyenne Mountain Air Station. More than 90 percent of the population of El Paso County is directly or indirectly served by the electric system. Additionally, Colorado Springs Utilities has an electric franchise to serve Manitou Springs through July 2024.

Colorado Springs Utilities' electric service area is shown in Figure 2-2 and is approximately 475 square miles serving 220,568 electric meter accounts as of December 2014. The overall area includes Colorado Springs, Manitou Springs, Chipita Park, Green Mountain Falls, parts of Security and other unincorporated areas of El Paso and Teller counties. The city's population alone has 438,130 residents as of 2013.

The electric transmission and distribution system consists of 232 miles of transmission lines and 3,506 miles of distribution lines, which includes 1,060 miles of overhead lines and 2,678 miles of underground lines.

Figure 2-2: Colorado Springs Utilities Service Territory as of January 2015



The most recent electric system peak of 908 MW was recorded in June 2012. The system peak in 2014 was 879 MW with a 60.5 percent annual load factor. Residential, commercial and industrial loads are each roughly one third of the 4,656,159 megawatt-hours (MWh) of the 2014 electric system load.

Residential average annual use per customer in 2014 was 7,562 kilowatt hours. The 10 largest customers of the electric system in 2014 had consumption of 762,011 MWh, or 17.9 percent of sales. The system's military customers purchase a small portion of their power from Western.

2.2 Electric Generating Units

Colorado Springs Utilities owns and operates 10 thermal generating units and six hydroelectric units totaling 1,072 MW of installed generation capacity, as shown in Table 2-1 and Figure 2-3. Most of the energy is generated from 462 MW of coal-fired capacity and the natural gas-fired 460 MW Front Range Power Plant. Capacity ratings may differ slightly between summer and winter.

Table 2-1: Existing Generation Resources

Generation	Summer Capacity (MW)	Winter Capacity (MW)	Unit Type	Primary Fuel
Ruxton	1	0	Conventional Hydro	
Manitou 1	2.5	2.5	Conventional Hydro	
Manitou 2	2.5	2.5	Conventional Hydro	
Manitou 3	0.46	0.46	Conventional Hydro	
Tesla Hydro	28	28	Ponded Hydro	
Cascade	0.85	0.85	Conventional Hydro	
Birdsall 1	16	16	Steam Turbine	Natural gas
Birdsall 2	16	16	Steam Turbine	Natural gas
Birdsall 3	23	23	Steam Turbine	Natural gas
Drake 5	46	46	Steam Turbine	Coal
Drake 6	77	77	Steam Turbine	Coal
Drake 7	131	131	Steam Turbine	Coal
Nixon 1	208	208	Steam Turbine	Coal
Nixon 2	30	32	Combustion Turbine	Natural gas
Nixon 3	30	32	Combustion Turbine	Natural gas
Front Range	460	480	Combined-Cycle	Natural gas
Total generation	1,072	1,095		

Figure 2-3: Clockwise from top left: Ruxton, Birdsall, Drake, Tesla, Front Range, and Nixon

Coal units are typically operated as base load facilities, while natural gas and hydro units are used to meet intermediate and peaking loads. In December 2010 the organization fully acquired the additional half of the Front Range Power Project that it did not already own. When economical, Colorado Springs Utilities also purchases market power as needed to supplement existing generation resources.

Colorado Springs Utilities is a member of the Rocky Mountain Reserve Group, a group of power suppliers operating in Colorado, Wyoming, Nebraska and South Dakota. Membership advantages include the pooling of reserve capacities and providing mutual assistance during generator outages.

2.3 Purchase Power Contracts

The Colorado Springs Utilities electric resources are supplemented with long-term power purchase contracts. These are shown in Table 2-2 and Figure 2-4.

Table 2-2: Purchase power contracts

Purchases	Summer Capacity (MW)	Winter Capacity (MW)	Commission Year
Western - LAP	61	57	
Western – SLCA/IP	15	60	
Wind	2	2	
U.S. Air Force Academy Solar	5.25	5.25	2011
Solar Garden Pilots	2	2	2011, 2012, 2015
Solar Garden Tariff	2	2	2015
Total Purchases	87	128	

Figure 2-4: The USAFA 5.25 MW solar project

Western Area Power Administration Purchases:
Colorado Springs Utilities receives allocations of federal hydropower under contracts with Western's Salt Lake City Integrated Area Projects (SLCA/IP), and Loveland Area Projects (LAP). The SLCA/IP contract provides 15.149 MW in the summer and 60.324 MW in the winter. The LAP contract provides 60.683 MW in the summer and 57.126 MW in the winter. Both contracts also provide some Renewable Energy Certificates (RECs) for energy provided from Western's small hydro facilities. These contracts currently extend to September 30, 2024. In the summer of 2015 the Utilities Board approved a renewal for the next LAP contract term of 2024 to 2054. Western is working on the extension of the SLCA/IP contract.

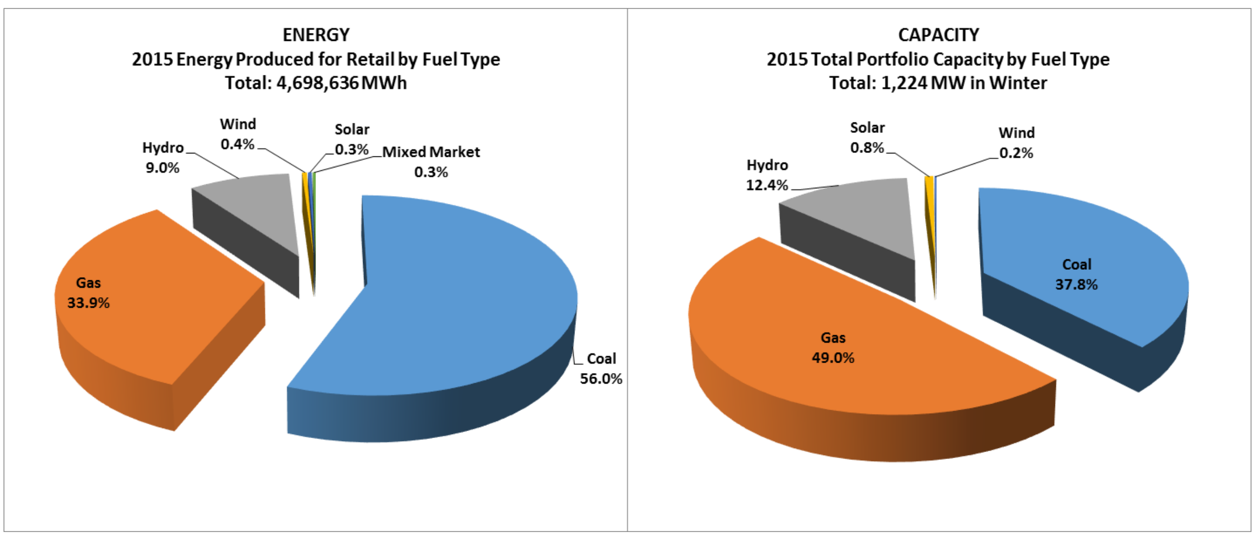
Wind Power Purchase:
The 2 MW wind contract (3 MW for January 1 through April 13) was signed with Xcel Energy starting on Jan. 1, 2015 and expiring Dec. 31, 2016, for a total of 20,000 MWh each year.

U.S. Air Force Academy Solar Generating Station Purchase:
The 5.25 MW solar contract from the USAFA Solar Project began commercial operation on July 1, 2011. SunPower owns and operates the facility, and Colorado Springs Utilities has the option to purchase the project after 10 years. Its 18,888 solar panels cover 43 acres.

Community Solar Gardens (CSG)
In October 2011, Colorado Springs Utilities received approval from the Utilities Board to offer a Community Solar Garden Bill Credit (Pilot Program) Tariff for up to 2 MW total. The pilot program sold out almost immediately with four separate 500 kW installations. The Community Solar Garden Program provides an opportunity for electric customers to own a solar PV system without it being installed on their home or business. In 2014, a new CSG tariff was created and an additional 2 MW was completed in July of 2015.

Figure 2-5 shows the actual energy and capacity mix for Colorado Springs Utilities in 2015.

Figure 2-5: Energy and capacity mix of resources by fuel type for 2015



2.4 Transmission System

Electric transmission access is an important consideration when contemplating adding resource options. Colorado Springs Utilities is interconnected with Western, Xcel Energy and Tri-State Generation and Transmission. The Colorado Springs Utilities transmission system is geographically limited to the load serving area in and around Colorado Springs resulting in limited access to resources outside of the city. As existing units are considered for decommissioning, Colorado Springs Utilities will include the financial impact of any necessary transmission system modifications that may be needed.

As a member of the Colorado Coordinated Planning Group (CCPG) and WestConnect, Colorado Springs Utilities is positioned to take advantage of partnering opportunities in transmission projects that could provide additional access to economical sources of conventional and renewable generation.

3.0 Forecast Assumptions

This section provides key load, fuel and market price forecasts used in the EIRP as well as high and low ranges. Any capacity deficit as a result of the load forecast is also shown in this section.

3.1 Electric Load Forecast and Capacity Requirements

3.1.1 Electric Load Forecast

The 20-year electric load forecast was developed by Colorado Springs Utilities' staff during the first quarter of 2015. The forecasting methodology uses econometric modeling with incremental end-use analyses. In econometric modeling, historic data for the number of customers and use per customer are related to explanatory variables such as price, economic activity, monthly factors and weather variables. The historic relationship is then used to forecast the future number of customers and use per customer. Itron's Metrix ND modeling package was used to estimate the regression equations for customers and use per customer.

Econometric modeling requires a forecast of economic activity. The key dependent variable for customer forecasts is the population forecast from the Colorado State Demographer in the Colorado Department of Local Affairs. Using this forecast helps ensure consistency between Colorado Springs Utilities' forecast and other government forecasts. Economic variables, other than population, are provided by a local economist with the Southern Colorado Economic Forum for El Paso County.

In addition to economic data, the impact of price increases is also incorporated in the forecast. The econometric analysis determines price elasticity, the amount by which sales change for a given change in price. The prices used in the econometric analyses are typical electric bills by customer class. Forecasts of typical electric bills are pulled from Colorado Springs Utilities' financial model and incorporate the impact of future sales levels, fuel costs, budgeted capital, and operations and maintenance costs. Typical electric bills increase approximately 1.2 percent per year for residential customers and 1.8 percent per year for non-residential customers over the forecast horizon. These estimates include electric cost adjustment (ECA) and gas cost adjustment (GCA), increased operating costs, and planned infrastructure additions.

Econometric models are not designed to include the impact of changes that were not present in the historical data. As a result, incremental end use or engineering modeling is used in the forecast to include the effect of future changes. Federal appliance efficiency standards for refrigerators and freezers have changed several times in the past, and are anticipated to be reflected in the historical data. Future appliance standards for refrigerators and freezers, therefore, do not require an adjustment of the econometric forecast. The impact of future laws or standards for other major appliances or end uses needs to be incorporated in the forecast, however. New federal laws or appliance efficiency standards have been announced for incandescent fluorescent lighting, air conditioners, clothes washers, dishwashers, furnace fans, ranges and ovens. The projected impact of these changes are incorporated as an adjustment to the econometric forecast based on estimates of the usage reduction for each end-use due to the law or standard, saturation rates for these appliances, and the replacement rates of the old equipment.

The electric load forecast also implicitly incorporates Colorado Springs Utilities' historic DSM program impact, but not new DSM programs. New or incremental DSM programs are analyzed in the resource planning process.

Table 3-1, Figure 3-1, and Figure 3-2 present the electric load forecast published in April 2015.

Table 3-1: 2015 Electric load forecast prior to demand-side management

2015 Electric Load Forecast					
	System Energy		System Peak		System Load Factor
	Level	Change	Level	Change	Annual
	(GWh)	(%)	(MW)	(%)	(%)
2014	4,655		879		60%
2015	4,681	0.6%	905	3.0%	59%
2016	4,718	0.8%	917	1.3%	59%
2017	4,744	0.5%	926	1.0%	58%
2018	4,774	0.6%	934	0.8%	58%
2019	4,811	0.8%	941	0.8%	58%
2020	4,853	0.9%	948	0.8%	58%
2021	4,887	0.7%	956	0.8%	58%
2022	4,933	0.9%	964	0.9%	58%
2023	4,980	1.0%	973	0.9%	58%
2024	5,033	1.1%	982	0.9%	58%
2025	5,075	0.8%	989	0.7%	59%
2026	5,113	0.8%	998	0.9%	59%
2027	5,152	0.8%	1,007	0.9%	58%
2028	5,192	0.8%	1,016	0.9%	58%
2029	5,231	0.8%	1,025	0.9%	58%
2030	5,271	0.8%	1,034	0.9%	58%
2031	5,311	0.8%	1,044	0.9%	58%
2032	5,352	0.8%	1,053	0.9%	58%
2033	5,393	0.8%	1,063	0.9%	58%
2034	5,434	0.8%	1,072	0.9%	58%
2035	5,476	0.8%	1,082	0.9%	58%

High and low ranges on the forecast were developed based on a 99 percent confidence interval for the high and mirroring the same percent forecast difference on the low side. The range represents plus and minus 8.5 percent for demand, as shown in Figure 3-1, and plus and minus 9.8 percent for energy as shown in Figure 3-2.

Flat and declining forecasts were also developed based on a trend of historical growth rates shown in Figure 3-3. The flat forecast assumes this trend levels out at roughly 0 percent growth while the declining forecast assumes the trend continues downward into negative growth rates. Colorado Springs Utilities has experienced declining growth rates and the chart shows that this is not unique to our utility.

Figure 3-1: 2015 Load forecast demand scenarios, not including potential future DSM

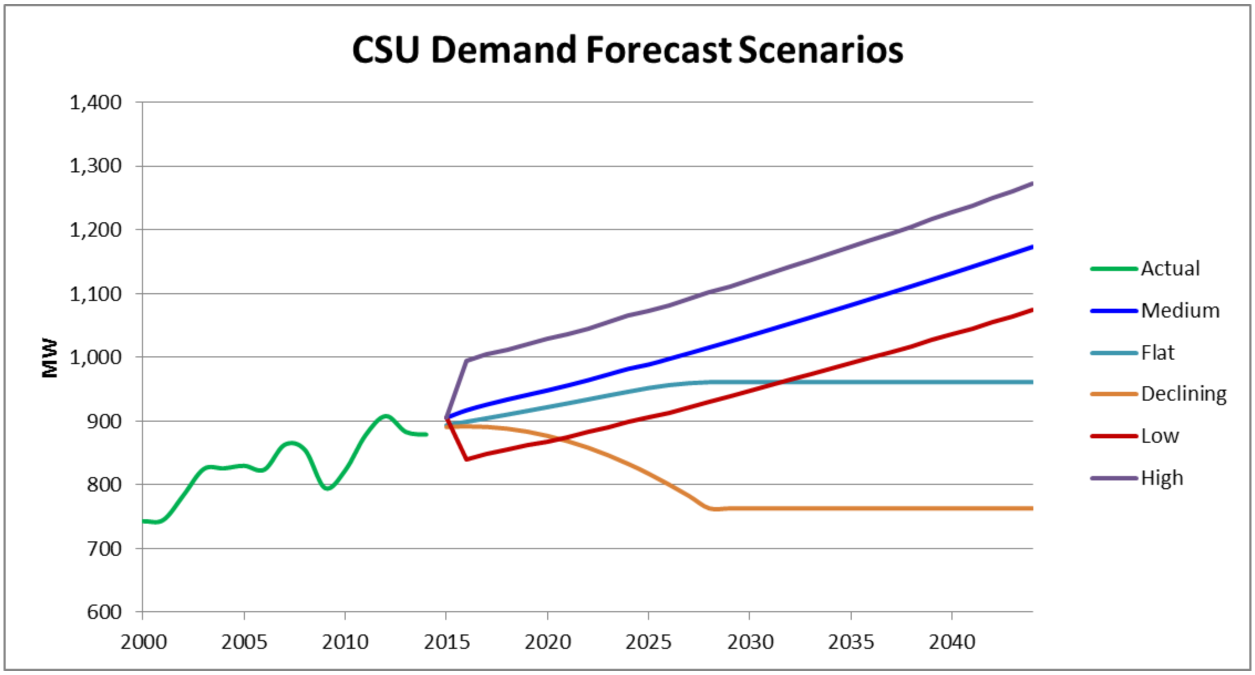


Figure 3-2: 2015 Load forecast energy scenarios, not including potential future DSM

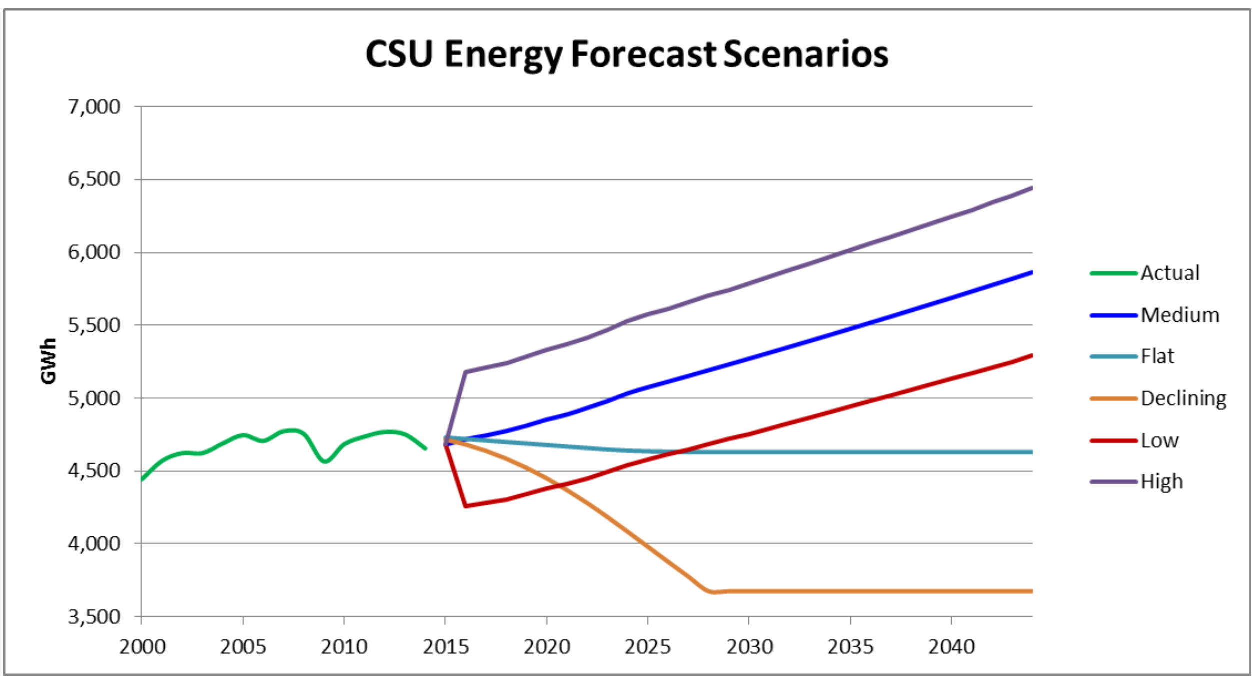
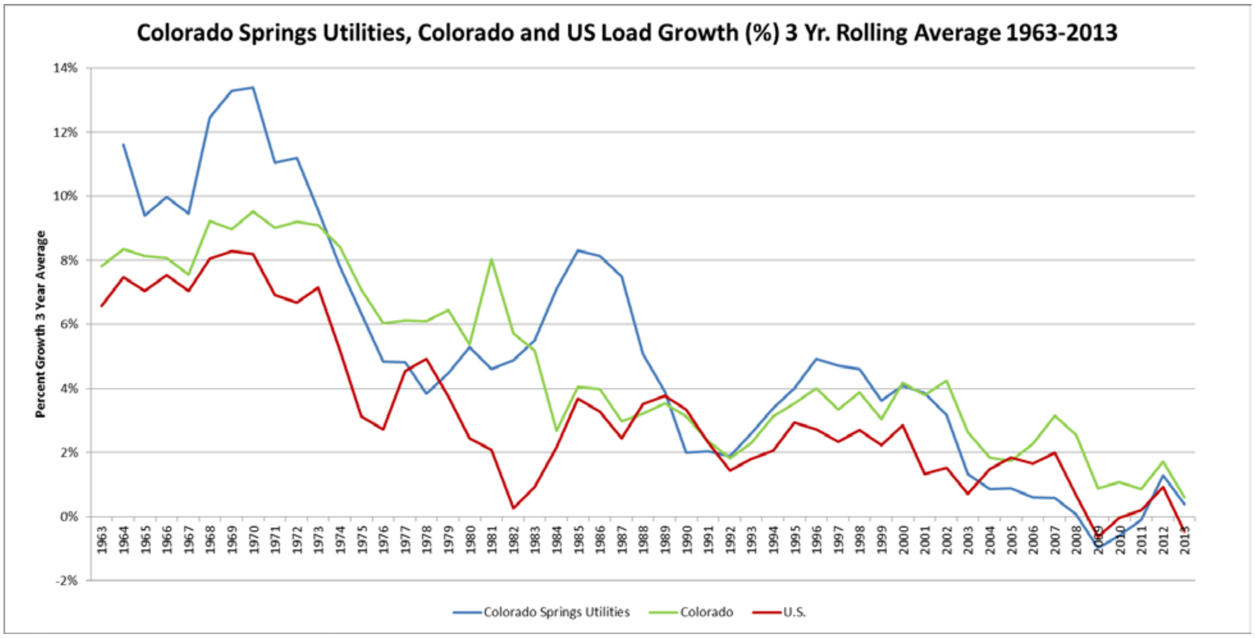


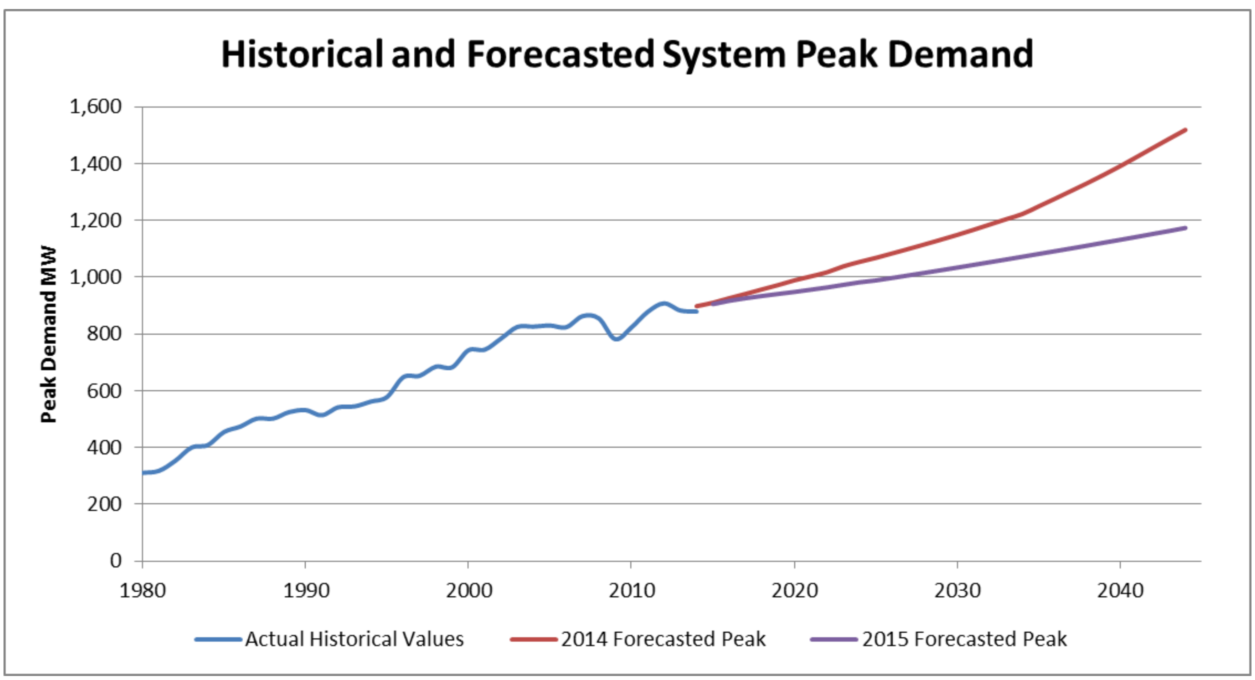
Figure 3-3: Colorado Springs Utilities, Colorado and US Energy Load Growth 1963-2013



Source: EIA Energy by state 2014 – Electricity Total Consumption (i.e. sold) - Million Kilowatthours

Figure 3-4 shows that Colorado Springs Utilities' demand was growing rapidly during the 1990s and flattened in the 2000s. Demand is projected to grow more slowly in the next several years due to slow economic recovery and the impact of appliance efficiency standards. This lower projected growth rate is one of the reasons an update to the EIRP is appropriate.

Figure 3-4: Colorado Springs Utilities 2014 load forecast compared to 2015 load forecast



3.1.2 System Reserves and New Capacity Requirements

Colorado Springs Utilities' planning reserve margin is 18 percent of summer peak demand (excluding firm purchases from Western).

The reserve margin includes projected Rocky Mountain Reserve Group contingency reserves as well as projected regulating reserve requirements. In addition to projected operating reserves, the planning reserve requirements include reserves for uncertainty in forecasts of load and generation capacity.

These uncertainties make it prudent for Colorado Springs Utilities to maintain a planning reserve margin in this range. Several years are required to permit and build new generating units, or to create and deploy DSM programs that can reduce load growth. Delays can also be experienced as generating units are built. Actual penetration rates and load reductions from DSM programs may not achieve the projected values. Over a period of a few years, regional reserve margins may decline as loads grow faster than anticipated or as planned resource additions are delayed. The result of these risk events could be power shortages, price spikes and substantially higher purchase costs in regional power markets, and possibly brownouts or blackouts. Thus, a planning reserve margin is used to ensure that native electric loads have a high probability of being met.

Table 3-2 shows the status of Colorado Springs Utilities' resources, forecasted peak demand, and resulting reserve margins at the beginning of the EIRP. This table does not reflect any decommissioned or new capacity that may be identified as a result of the EIRP process. Adjustments to coal unit capacities shown in Table 3-2 due to emission control equipment are estimates and could be higher or lower based on actual capacity testing after installation.

Table 3-2: Electric resources, reserve margins and capacity requirements (MW) through 2034

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Planning Forecast	905	917	926	934	941	948	956	964	973	982	989	998	1,007	1,016	1,025	1,034	1,044	1,053	1,063	1,072
Less 6% DSM (reference case)	-7	-9	-12	-15	-17	-20	-27	-33	-39	-46	-47	-52	-56	-61	-67	-71	-72	-74	-76	-78
Net Load Requirement w/DSM	899	908	914	919	924	928	929	931	934	936	942	946	950	954	958	964	972	980	987	995
Generation Resources:																				
Drake 5	46	46	46	46	46	46	46	46	46	46	46	46	46	45	45	45	45	45	45	45
Drake 6	77	77	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Drake 7	131	128	128	128	128	128	128	128	128	128	128	127	127	127	127	127	127	127	127	127
Nixon 1	208	208	208	203	203	203	203	203	203	203	203	203	203	202	202	202	202	202	202	202
Nixon 2	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Nixon 3	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Birdsall 1	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Birdsall 2	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Birdsall 3	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Hydro	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Front Range	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460	460
Total CSU Generation	1,069	1,066	1,064	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,059	1,059	1,057	1,057	1,057	1,057	1,057	1,057	1,057
Purchased Power:																				
Front Range Purchase																				
Western Purchase - LAP	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61	61
Western Purchase - SLC (CRSP & WRP)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Solar Gardens Dependable	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
USAFA Solar Dependable	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total Purchases Under Contract	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
Total Current Resources	1,150	1,147	1,145	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,140	1,139	1,138	1,138	1,138	1,138	1,138	1,138	1,138
Reserve Margin MW	251	239	232	221	217	212	211	209	207	204	199	194	189	184	180	174	166	158	151	143
Reserve Margin %	31%	29%	28%	26%	26%	25%	25%	24%	24%	24%	23%	22%	22%	21%	20%	20%	19%	18%	17%	16%
Desired Reserve Margin	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
Desired Reserve (MW)	148	150	151	152	153	153	154	154	154	155	156	157	157	158	159	160	161	163	164	165
Surplus/(Deficit) after reserves	103	89	81	69	64	59	57	55	53	49	43	37	32	26	21	14	5	(5)	(13)	(22)

As a result of the flattening of demand in the decade of the 2000's and the impact of energy efficiency in the forecast, Table 3-2 shows that Colorado Springs Utilities has a planning reserve margin above 18 percent through 2031 (at the level of DSM used in the table). Under these demand forecast and DSM projections, Colorado Springs Utilities would need new, firm capacity resources to meet its load and reserve requirements after 2031. Other factors, such as renewable requirements, could add new resources earlier than firm resources are needed.

Note that one set of DSM impacts is shown in Table 3-2, the reference case of six percent, but alternative levels of DSM and energy efficiency are examined in the EIRP. Similarly, various unit decommissionings are considered which would also impact the year in which new capacity is needed.

3.2 Fuel and Electric Market Prices

Fuel and electric market prices are important assumptions in the EIRP. Our primary fuels are natural gas and coal. This section also includes a discussion of electric market prices, which are related to natural gas prices as natural gas generating units are often selling power into the market.

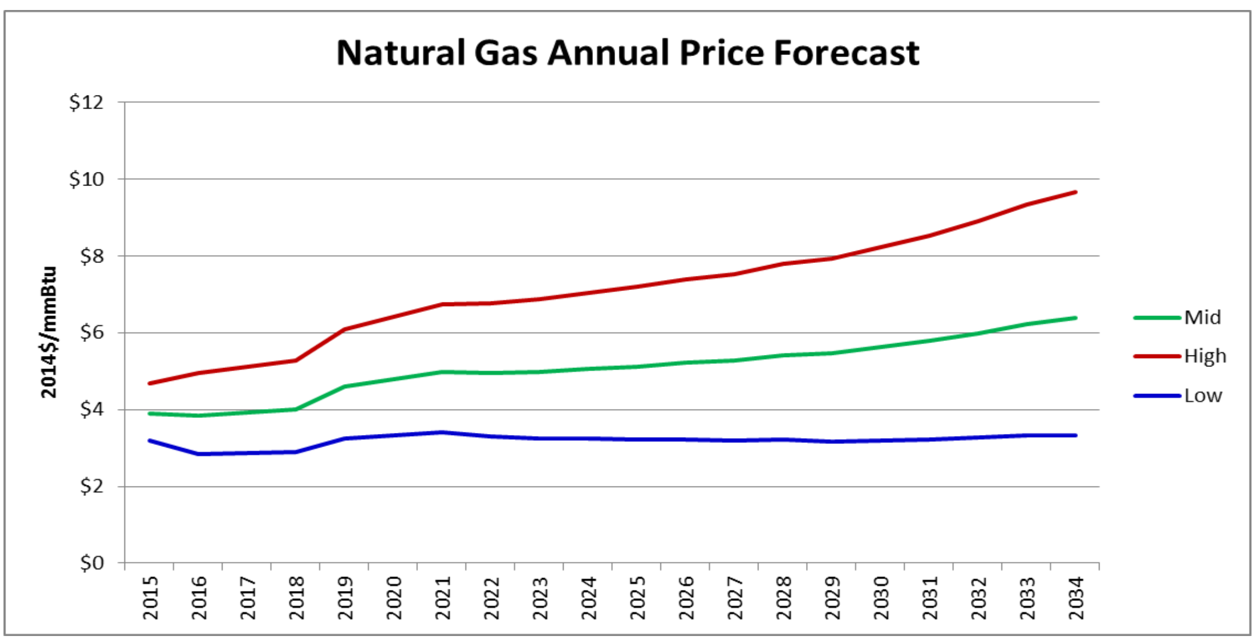
3.2.1 Natural Gas Prices

Natural gas commodity price forecasts are based on an internally derived blend of forward market information at Cheyenne Hub and CIG mainline, PIRA Energy Prices at Cheyenne Hub, and ABB Western Electric Coordinating Council's (WECC) Spring 2015 Reference Case forecasts at the Opal Liquid Market Index. Resulting forecast prices are shown in Figure 3-5. Transportation costs to deliver the fuel are also included for each natural gas unit.

Front Range Power Plant is connected to the 212A line which delivers high pressure gas directly to the plant under Kinder Morgan tariffed rates. Drake and Birdsall Power Plants are located on the natural gas local distribution company (LDC), which is also Colorado Springs Utilities. However, Drake and Birdsall are tariffed customers just like any other industrial customer on the LDC. Their fuel costs include applicable Kinder Morgan rates to transport gas to the city gates, plus the LDC's interruptible transport.

High and low prices are also based on the ABB WECC Spring 2015 forecasts. The percent error is determined and applied to the blended medium forecast to produce high and low forecasted prices.

Figure 3-5: Natural gas price forecast- expected (mid), high and low



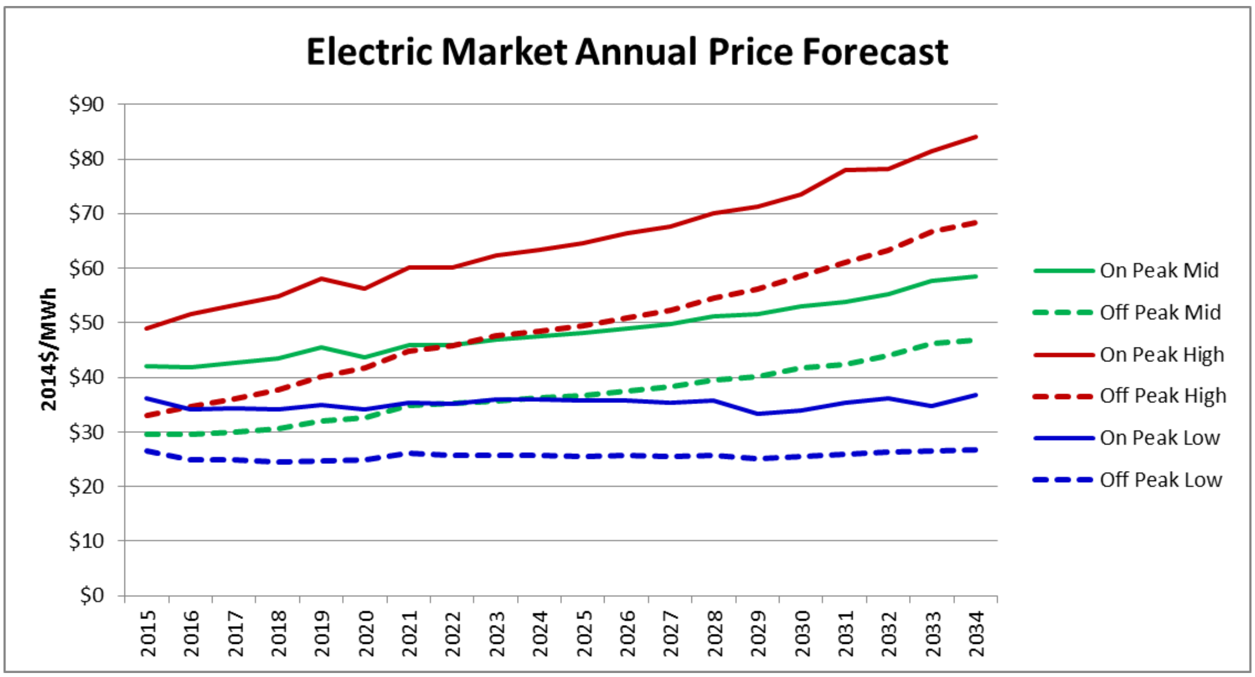
3.2.2 Electric Market Prices

Electric market prices were developed by Colorado Springs Utilities' Energy Supply Department based on forecasted natural gas prices in Figure 3-5, historical analysis, and ABB WECC Spring 2015 Reference Case forecasts at the CO-East forecast index.

Electric market purchases often come from natural gas-fired combined cycle power plants similar to the Front Range plant, so a portion of the forecast is based on the natural gas price forecast and a heat rate consistent with a natural gas-fired combined cycle. Electric market prices need to be consistent with the natural gas forecast, or the model will reduce or increase Front Range's operation and purchase power instead. This also means that in scenarios that changed fuel prices or power costs, electric market prices also needed to be changed.

High and low prices are also based on the ABB WECC Spring 2015 forecasts. The percent error is determined and applied to the blended medium forecast to produce high and low forecasted prices for on-peak and off-peak pricing. Resulting forecast prices are shown in Figure 3-6.

Figure 3-6: Electric Market price forecast- expected (mid), high and low



3.2.3 Coal Prices

The coal price forecast is comprised of the commodity prices plus coal transportation costs as per current contracts for Powder River Basin coal, which is used in all four Colorado Springs Utilities coal units. The coal forecast includes pricing components of daily price projections combined with ICAP United Pricing views, ABB WECC Spring 2015 Reference Case forecasts for delivered coal at the CO-East forecast index, and considerations for current market direction. Rail transportation is based upon current tariff delivery charges or embedded in the ABB WECC Spring 2015 Reference Case forecasts for delivered coal. Costs not included in forecasted prices are railcar lease and maintenance expenses. All four Colorado Springs Utilities coal units run on Powder River Basin coal shown in Figure 3-8 below.

High and low prices are also based on the ABB WECC Spring 2015 forecasts. Natural gas and coal prices are linked and often trend in the same direction. Therefore the percent high and low is based on the ABB natural gas price error and is only applied to the commodity portion of the delivered coal price, about 50 percent of the delivered price. Resulting delivered coal price forecasts are shown in Figure 3-7 below.

Figure 3-7: Coal price forecast- expected (mid), high and low

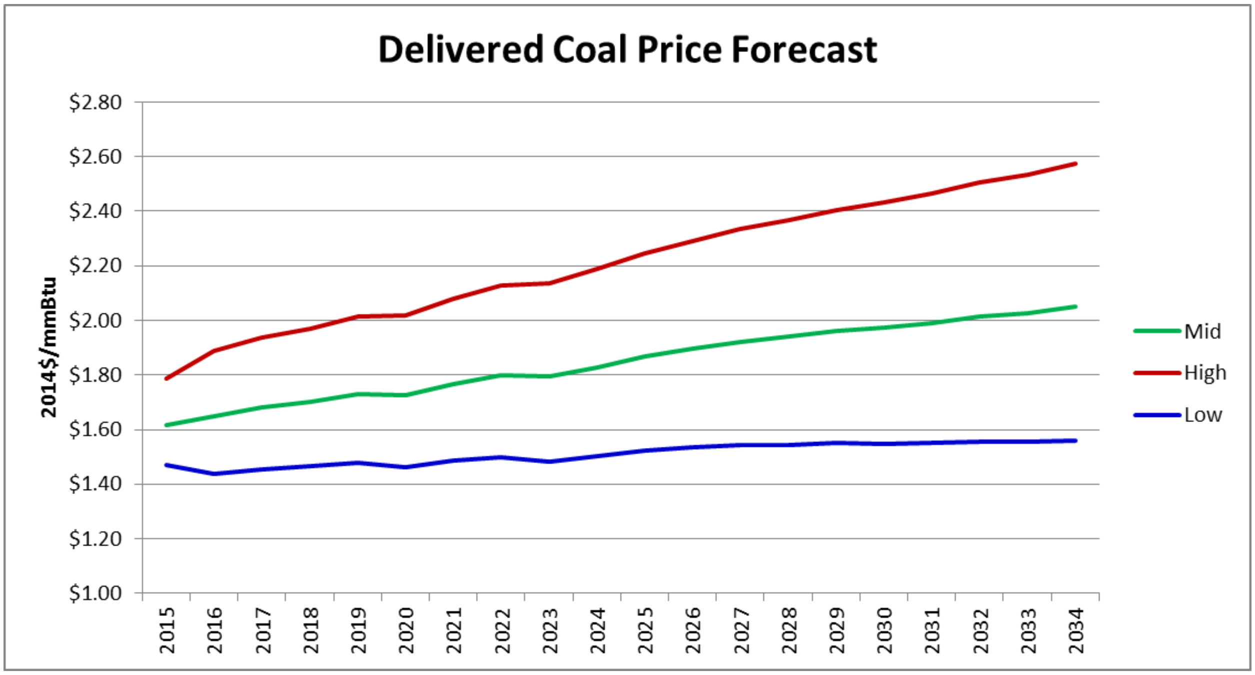


Figure 3-8: Coal mining operation in the Powder River Basin

4.0 Supply-Side Resource Options

Colorado Springs Utilities uses the ABB System Optimizer capacity expansion model for its EIRP. This model examines the existing system and then adds resources as needed to meet projected demand levels including reserves in a least-cost manner while observing environmental and operational requirements. Renewable resources such as hydroelectric (hydro), wind, biomass, biogas, solar thermal, and solar photovoltaic are evaluated with conventional resources. DSM programs were also evaluated on an integrated basis with other resource options.

Colorado Springs Utilities evaluated 26 conventional and renewable resource options, which are listed in Table 4-1, including a potential biogas project at the Solid Handling Disposal Facility (SHDF) on the Clear Spring Ranch (CSR) site shown in Figure 4-1. Any of these resources could be selected at any time to meet demand requirements, reduce the total cost of the portfolio, meet renewable energy standards, and/or reduce carbon dioxide. Conventional resource options include new natural gas-fired units, a new coal-fired unit with carbon capture and sequestration (CCS), an upgrade at the existing Nixon coal plant, an upgrade at the existing natural gas-fired Front Range plant, fuel cells, and nuclear options. Renewable resources include wind, solar thermal, solar photovoltaic, biogas, biomass, and hydro. Other resource options include municipal solid waste, battery storage, and several demand response (DR) alternatives. The new coal and small modular nuclear reactor (SMR) resources were added in response to public comments. Transmission costs for some of the renewable projects that would not likely be constructed on our system were included in their cost. Dual-fuel combustion turbines and reciprocating engines were also included to eliminate the cost of upstream firm fuel supply. Table 4-1 also shows capital costs, heat rates, operation and maintenance costs, and available dates for resource alternatives. Each resource is discussed in more detail in the following sections. These are screening level costs. If an option is selected, it means that the project would need to be analyzed in greater detail. Selection does not necessarily mean that a project would go directly to construction.

Any alternative could be considered as a power purchase agreement if the opportunity were available. While the EIRP selects resource options, a more detailed analysis occurs during procurement and selection as to whether the resource will be built or purchased.

Figure 4-1: Site of potential biogas generation project at Solid Handling Disposal Facility

Table 4-1: Resource alternatives data

Date Available	Fuel	Plant Type	Plant Characteristics: Nominal Capacity (MW)	Plant Characteristics: Heat Rate (Btu/kWh)	Plant Costs (2014$): Overnight Capital Cost ($/kW)	Plant Costs (2014$): Total Fixed Cost ($/kW-yr)	Plant Costs (2014$): Variable O&M Cost ($/MWh)	Capacity Factor	Source
2017	Coal	Nixon Optimized Plant Retrofit	6	10,200	$2,717.00	$0.00	Same as N1	92%	2
2025	Coal	Single Unit Advanced PC with CCS	650	12,000	$5,227.00	$80.53	$9.51	92%	1
2025	Nuclear	Small Modular Nuclear Reactors	360	$10.12/MWh	$4,514.52	$124.10	$1.89	92%	7
2020	Gas	Conventional CC	240	7,050	$963.59	$52.21	$3.75	85%	1
2020	Gas	Advanced CC	240	6,430	$1,074.97	$51.11	$3.40	85%	1
2019	Gas	Conventional CT	72.7	10,850	$1,032.56	$66.90	$16.07	85%	1
2019	Gas	Advanced CT	179.6	9,750	$738.48	$60.58	$10.79	85%	1
2019	Gas	LM6000 CT	36.5	9,787	$1,537.85	$58.07	$4.68	85%	3
2019	Gas	LMS100 CT	78.7	8,941	$1,201.07	$54.11	$3.70	85%	3
2020	Gas	Front Range Advanced Gas Path (AGP)	25	FR - 1.6%	$1,400.00	$0.00	Same as FR	35%	3
2019	Gas	Reciprocating Engine	7.87	8,300	$1,462.00	$62.51	$3.70	85%	3
2022	Gas	Fuel Cells	10	9,500	$7,247.26	$51.89	$44.74	85%	1
2019	Gas or Oil	LM6000 - Dual Fuel	36.5	9,787	$1,845.42	$4.61	$4.68	85%	3
2019	Gas or Oil	Reciprocating Engine - Dual Fuel	7.866	8,300	$1,754.40	$17.17	$3.70	85%	3
2022	Biomass	Biomass BFB	20	13,500	$4,151.80	$109.90	$5.47	85%	1
2018	Wind	Onshore Wind	50	N/A	$2,371.48	$100.55	$0.00	35%	1
2018	Solar	Solar Thermal	100	N/A	$4,902.69	$69.98	$0.00	20%	1
2018	Solar	CSR Solar Thermal	20	N/A	$4,161.60	$69.98	$0.00	20%	2
2016	Waste	Biogas Cogen Recip at SHDF	1.7	N/A	$1,994.00	$11.39	$17.81	20%	2
2017	Solar	Small Photovoltaic Single Axis	25 x 10MW	N/A	$1,351.00	$28.87	$1.24[a]	25%	6
2022	Waste	Municipal Solid Waste	50	18,000	$8,215.41	$408.69	$9.10	92%	1
2022	Hydro	Small Hydro	1	N/A	$7,107.48	$39.27	$0.00	25%	1
2016	DR	Conservation Voltage Reduction	18	N/A	$207.33	$8.11	$0.00	0%	4
2016	DR	Residential Demand Reduction	8 x 1.9MW	N/A	$462.00	$20.20	$0.00	0%	4
2016	DR	Commercial Demand Reduction	6 x 5.0MW	N/A	$750.00	$475.00	$0.00	0%	4
2016	Battery	Energy Storage System	50 x 2MW	N/A	$3,206.25	$12.12	$0.00	0%	5

Sources:

1	United States. Energy Information Administration. Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants. Washington DC: EIA Office of Energy Analysis, 2013. EIA Study Apr 2013. <http://www.eia.gov/forecasts/capitalcost/> *Uses RMPA location-based Overnight Capital Cost adjustment and Denver location-based capacity adjustments.
2	In-House Evaluation
3	GE Estimate
4	Indicative pricing proposals - Term for renewable PPAs is 25 years. Term for conventional PPAs is 5 years.
5	Nikola Power
6	Solar Energy Industries Association U.S. Solar Market Insight Report Q3 2014. A 30% Invetment Tax Credit is assumed in this price.
7	Patriot Solutions International

Notes:

a	Variable O&M for solar is integration cost based on a study by Argonne National Laboratory for Arizona Public Service
	Resources will be evaluated at the time of implementation to determine if they will be self-build or purchase
	Total Fixed O&M includes any necessary transmission or upstream fied fuel transportation costs

Each of these resources is discussed in more detail in Sections 4.1 and 4.2 of this report.

4.1 Supply-Side Resource Options – Renewable Energy

Renewable energy is defined as an energy source that is replaced or replenished rapidly by natural processes. Its technologies generally have a lower environmental impact than traditional fossil-fueled resources. Solar, wind, hydropower, geothermal and various types of biomass are considered renewable energy. As part of the renewable energy options analysis, Colorado Springs Utilities will consider renewable energy programs at customer facilities as well as utility-scale projects.

4.1.1 Renewable Energy Options

Renewable resources evaluated in the EIRP include:

20 MW Biomass Bubbling Fluidized Bed (BFB) – This greenfield resource uses woody biomass to create steam in a stand-alone BFB boiler. The boiler's superheated steam is then run through a turbine-generator to create electricity. Biomass has previously been burned in the existing Drake Unit 5.

50 MW Onshore Wind - This resource consists of wind turbine generators that convert wind energy directly into electricity. Given Colorado Springs is not ideal for wind generation, transmission costs have been included and contain the cost of integrating intermittency through the ancillary service portion of a transmission purchase. Wind was limited to three units (150 MW total) based on what can reasonably be integrated into our system during a low load night while keeping Nixon 1 and Front Range online at minimum.

100 MW Solar Thermal – This uses a concentrating solar thermal process to generate superheated steam used to turn a new turbine-generator and create electricity.

20 MW Clear Spring Ranch Solar Thermal – The existing steam turbine-generator at Front Range Power Plant would use the superheated steam from a concentrating solar process to generate electricity.

1.7 MW Biogas Cogen Recip at SHDF – Biogas from the Clear Spring Ranch Solid Handling Disposal Facility would be used to generate electricity in reciprocating engines while capturing the waste heat and using it at the SHDF facility.

10 MW Small Photovoltaic Single-Axis – Photovoltaic panels would convert sunlight directly into electricity while following the arc of the sun throughout the day to maximize energy production. This resource was limited to 25 units (250 MW total) based on what can reasonably be integrated onto Colorado Springs Utilities' system during a low load day while keeping Nixon 1 and Front Range online at minimum to ensure reliable integration.

50 MW Municipal Solid Waste – This resource uses refuse-fired boilers to burn municipal solid waste. The heat is used to generate steam which can be used to run a turbine-generator and create electricity.

1 MW Small Hydro – Up to six hydro units, similar to the Cascade and Manitou 3 units, would convert energy from high pressure water to electricity using locations identified throughout the Colorado Springs Utilities raw water network.

18 MW Conservation Voltage Reduction (CVR) – Colorado Springs Utilities would reduce circuit voltage, thereby reducing power consumption, during peak times as a form of demand response.

1.9 MW Residential Demand Reduction – An existing air-conditioning load cycling program would be expanded for residential customers as a form of demand response. Installations were limited to eight

(15.2 MW total) based on what was assumed to be a reasonable number of eligible customers. This option would be in addition to installations being done as part of DSM initiatives in the Energy Vision.

5 MW Commercial Demand Reduction – This resource relies on a number of methods at commercial sites to reduce demand on-call including customer-side generators. It is based on estimates from aggregating companies that provide this service and is limited to six installations (30 MW total) based on third-party estimates for the Colorado Springs Utilities system.

4.1.2 Biogas

As a four-service utility, Colorado Springs Utilities has the benefit of housing both electric generation and wastewater treatment operations under one roof. One advantage in the context of renewable energy is a low cost option for “digester gas,” or “biogas" utilization. While biogas is a waste by-product in the wastewater treatment process, it is also a methane-rich fuel that can be used for power generation. Currently, less than half of the biogas generated is used for building heat in the winter and maintaining an optimal 95 degrees Fahrenheit reaction temperature in the digesters themselves. With a methane gas content of approximately 60 to 65 percent, it’s a valuable resource with a heating value of roughly 600 British Thermal Unit (Btu) per standard cubic foot (scf) (compared to about 1,000 Btu per scf for natural gas). The digester facility is located on Clear Spring Ranch and currently flares off roughly 150 million scf per year.

The last EIRP considered piping the excess biogas to the Nixon 1 boiler a short distance away, however more detailed analysis showed a combined heat and power design that used all of the biogas while providing process heat would be more beneficial. Quotes were obtained for reciprocating engines and gas scrubbing units that will remove moisture, siloxanes and other corrosive gas components such as sulfur. The biogas projected was estimated to contribute about 1.7 MW of qualifying renewable energy.

4.1.3 Solar Dependable Capacity

Solar energy is not a dispatchable resource, so it can’t be called upon at any moment and its use is restricted to available sunlight. However, capacity is typically needed most during hot, sunny afternoons when air-conditioners are running, and solar power has demonstrated that at least some portion of its installed capacity is operating dependably during these hours. Given that solar installations on the Colorado Springs Utilities system are a small portion of total capacity, a simplified analysis was done to estimate the amount of dependable capacity that could be used for planning purposes. If solar becomes more prominent, a more detailed Effective Load Carrying Capability study or other analysis may be needed.

For this EIRP, actual solar output during the top 10 system peak demand hours of each month was analyzed. Fixed and tracking solar arrays are expected to have different levels of coincidence during the late afternoon. Even different types of fixed solar arrays, such as community solar gardens and rooftop solar, can perform differently. Rooftops may be less optimum given less flexibility with panel direction and more shading. Table 4-2 shows the percentages used for each type of solar system.

Table 4-2: Percent of nameplate capacity counted as dependable capacity for various solar designs

Single-Axis Tracking	Fixed Solar Garden	Fixed Rooftop
58%	46%	37%

4.1.4 Colorado Renewable Energy Standard

In November 2004, Colorado voters approved an initiative that created a renewable energy standard for retail electric utilities in Colorado that serve more than 40,000 customers. The language of that initiative is codified in C.R.S. Section 40-2-124 (Colorado Renewable Energy Standard or CO RES) and it has been subsequently modified several times by the Colorado General Assembly. For municipal utilities like Colorado Springs Utilities, CO RES requires that energy from qualifying renewable energy resources must be at least one percent of electric retail sales for the years 2008 through 2010, three percent for the years 2011 through 2014, six percent for the years 2015 through 2019 and 10 percent for year 2020 and thereafter.

The CO RES requires that this this electricity come from qualifying renewable energy resources, which include solar, wind, geothermal, biomass, existing hydroelectric generation with a nameplate rating of 30 megawatts or less and new hydroelectric generation with a nameplate rating of 10 megawatts or less. It allows utilities to generate directly or purchase the power generated from qualifying renewable resources, or to acquire the environmental attributes of power generated from these resources in the form of Renewable Energy Certificates. Utilities may both buy and sell the RECs associated with their qualifying renewable energy resources.

The CO RES also establishes a maximum retail rate impact for compliance with CO RES requirements of one percent of the total electric bill annually for each customer of a cooperative electric association that is a qualifying utility and two percent for each customer of an investor-owned utility.

In 2005, Colorado Springs City Council, in its capacity as Colorado Springs Utilities' Board of Directors, adopted a resolution to voluntarily comply with the CO RES requirements. In 2006, Colorado Springs Utilities submitted a Self-Certification Statement to the Public Utilities Commission for the State of Colorado (CO PUC) regarding its Renewable Energy Standard. The Self-Certification Statement filed with the CO PUC is for informational purposes only and is not subject to CO PUC approval.

Colorado Springs Utilities complies with the statutory requirements of C.R.S. Section 40-2-124 and is substantially similar to that adopted by the CO PUC through its RES rules. Colorado Springs Utilities chose to self-certify with the CO RES because of the belief that it is appropriate to complement its portfolio of electric supply options with the full range of technology and fuel diversity.

Colorado Springs Utilities measures and reports its renewable energy levels as part of the EIRP and as part of the CO RES requirements. The renewable energy levels are one of the scorecard measures upon which the chief executive officer of Colorado Springs Utilities is measured.

At the time of the EIRP, Colorado Springs Utilities expects to have sufficient qualifying renewable energy resources to comply with the CO RES requirements through 2023. In 2006, it made a substantial purchase of RECs which were received during the years 2006 through 2010. The organization also acquires RECs for its qualifying hydro power from Western. The RECs will be used in addition to qualifying renewable energy generation from Colorado Springs Utilities' hydroelectric generating units and various solar power RECs to comply with the CO RES.

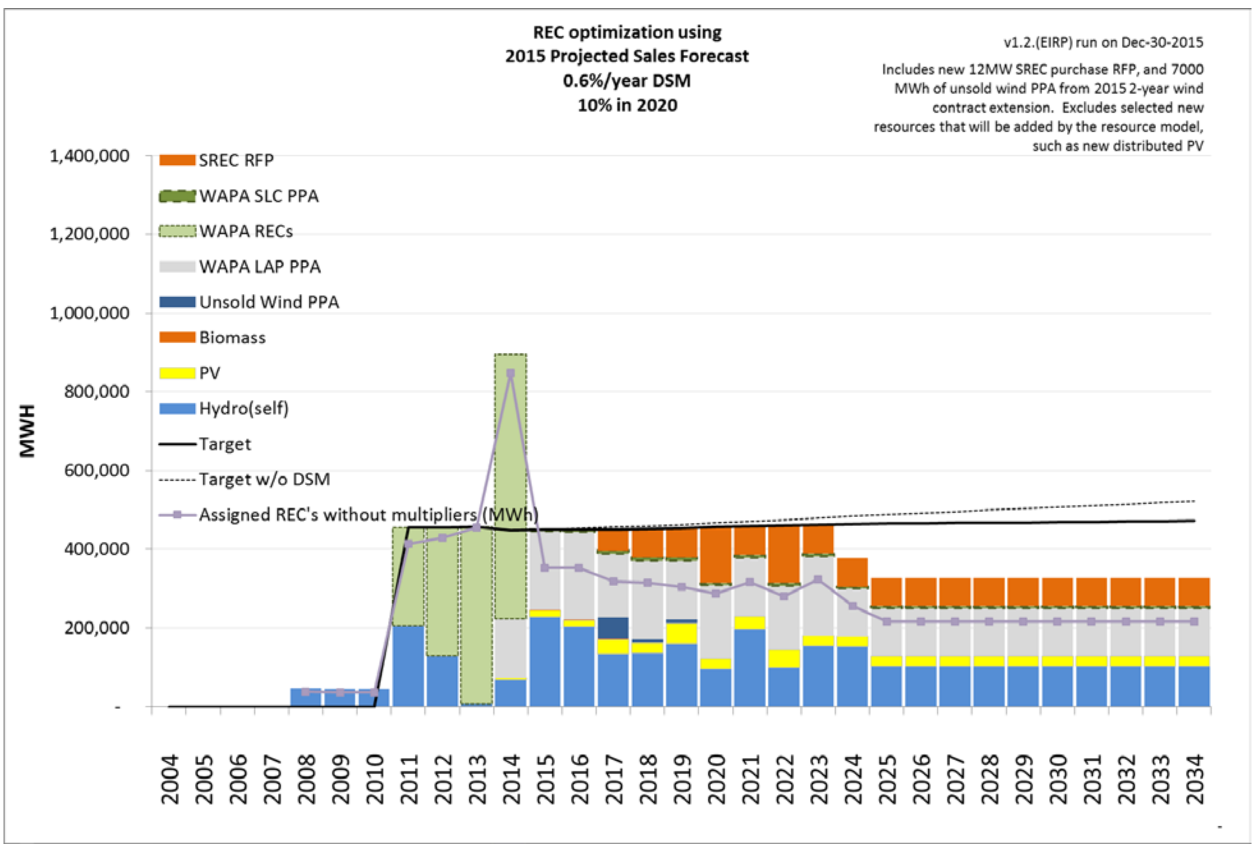
The EIRP examined ways to comply with the CO RES or alternative levels of renewable when additional qualifying renewable energy resources were required. Renewable energy was analyzed at low (10 percent by 2020), medium (20 percent by 2020), and high (30 percent by 2020) levels. These three levels were evaluated to cover a range of possible future compliance requirements for municipal utilities and investor-owned utilities. The range also provided a means to identify the costs associated with higher levels of renewables. In addition to CO RES scenario levels, a fourth level of 50 percent by 2030 was evaluated as a request from a CAG member during the public process. Table 4-3 indicates the annual levels of renewable energy evaluated in the EIRP.

Table 4-3: Renewable energy levels studied

Starting Year	Low	Medium	High	50% by 2030
2015	10%	15%	15%	15%
2020	10%	20%	30%	20%
2025	10%	20%	30%	35%
2030	10%	20%	30%	50%

RECs can also be banked and used up to five years past the generation year, so an optimization is needed to determine how RECs could be used to meet the various RPS scenario levels. The optimization pictured in Figure 4-2 shows Colorado Springs Utilities will be in compliance with the CO RES requirement of 10 percent through 2023 without any new resource additions. New renewable energy would be needed after that to maintain compliance. An optimization like this is done for each renewable energy scenario to identify when additional RECs will be needed.

Figure 4-2: REC optimization for EIRP reference case at time of EIRP



4.2 Supply-Side Resource Options – Conventional Resources

Conventional resources that were evaluated in the EIRP are described below:

6 MW Nixon Optimized Plant Retrofit – Efficiency and fuel-free capacity improvements at the existing Nixon 1 Coal Plant. This resource has been updated from the previous EIRP to include just an efficiency improvement and resulting capacity increase as opposed to a fuel increase option that was previously considered.

650 MW Advanced Pulverized Coal with Carbon Capture and Sequestration (CCS) – A separate coal-fired, steam-electric generating unit with CCS which was added as a result of customer feedback during the public process.

360 MW Small Modular Nuclear Reactor (SMR) – Two 180 MW SMRs would be used to generate steam which then turns a turbine-generator to generate electricity.

240 MW Conventional Combined Cycle Unit – This facility uses two natural gas-fueled, F-class combustion turbines (CTs) and associated electric generators, two heat recovery steam generators, and a steam turbine and generator operating in “combined-cycle” mode for higher efficiency. It represents half of the capacity assuming the unit could be built with other regional partners.

240 MW Advanced Combined Cycle Unit – This facility uses one natural gas-fueled, H-class CT and associated electric generator, one heat recovery steam generator, and one condensing steam turbine with associated generator operating in combined-cycle mode. It represents half of the capacity assuming the unit could be built with other regional partners.

72.7 MW Combustion Turbine – A turbine similar in size to a conventional E-Class combustion turbine in simple-cycle mode using natural gas to combust compressed air which then turns a turbine-generator.

179.6 MW Combustion Turbine – This turbine is similar in size to a state-of-the-art F-Class combustion turbine in simple-cycle mode. It uses natural gas to combust compressed air which then turns a turbine-generator.

36.5 MW LM6000 – This combustion turbine is similar in MW size to the GE LM6000 aero derivative combustion turbine in simple-cycle mode. It uses natural gas to combust compressed air which then turns a turbine-generator. A dual-fuel option was also considered to allow interruptible fuel supply.

78.7 MW LMS100 – A turbine similar in size to the GE LMS100 combustion turbine in simple-cycle mode. It uses natural gas to combust compressed air which then turns a turbine-generator.

25 MW Front Range Advanced Gas Path (AGP) – This resource would modify the existing Front Range combustion turbines with advanced parts that would increase the capacity and improve its efficiency.

7.87 MW Reciprocating Engine – This option uses a piston engine that converts pressure from internal combustion into rotating motion to turn a generator. A dual-fuel option was also considered to allow interruptible fuel supply.

10 MW Fuel Cells – Using multiple phosphoric acid fuel cell units, each with a power output of 400 kW, this resource has a total output of 10 MW.

5.0 Demand-Side Management Resource Options

DSM is the planning and implementation of utility activities to encourage customers to modify their level and pattern of electricity use in order to change the utility's load shape. By modifying load use, DSM programs benefit both the utility and its customers. Colorado Springs Utilities considers DSM programs as alternative resource options in creating a least-cost plan to meet future energy needs. Changes in the timing and magnitude of electricity demand through DSM can make more productive and cost-effective use of generating resources. Customers benefit because they have more opportunities to control their energy use and overall bill. Colorado Springs Utilities offers a comprehensive portfolio of electric DSM programs to its customers. Details of the current electric DSM programs are listed in Appendix A.

Colorado Springs Utilities first created a DSM Strategic Plan in 2004. The plan set a long-term direction for defining Colorado Springs Utilities' role in shaping customers' energy use with the goal of creating value for its citizen owners and contributing to the organization's core business.

In the 2004 EIRP electric DSM programs selected for implementation were based on "best practice" programs commonly implemented by other utilities nationwide. The 2008 EIRP public process identified an increased emphasis on expanding DSM efforts, which has become a clear and consistent theme in public input to electric resource plans ever since.

5.1 2009 Electric DSM Potential Study

In order to more comprehensively evaluate DSM programs and to reach higher and more aggressive long-term electric DSM targets, a comprehensive electric DSM potential study was recommended in the 2008 EIRP and subsequently completed by Summit Blue Consulting in 2009. The Summit Blue DSM Potential Study assessed achievable electric DSM potential within the electric service territory for existing and new residential, commercial, and industrial sectors over the next 20 years (2009-2028) as follows in Table 5-1 and Table 5-2:

Table 5-1: 2009 DSM Potential Study results for 2009-2018

Scenario	**2009-2018 Achievable Potential Cumulative – 10 years Annual Average**		
	Energy Savings as % of Sales	Demand Savings as % of Peak	Costs as % of Revenue
High Case	0.75%	1.12%	2.08%
Medium Case	0.57%	0.85%	1.54%
Low Case	0.34%	0.55%	0.89%

Table 5-2: 2009 DSM Potential Study results for 2009-2028

Scenario	**2009-2028 Achievable Potential Cumulative – 20 years Annual Average**		
	Energy Savings as % of Sales	Demand Savings as % of Peak	Costs as % of Revenue
High Case	0.50%	0.75%	1.59%
Medium Case	0.44%	0.64%	1.27%
Low Case	0.35%	0.52%	0.95%

Southwest Energy Efficiency Project (SWEEP) provided feedback recommending Colorado Springs Utilities pursue a more aggressive energy savings DSM goal of 10 percent cumulative savings from 2011-2020 based on SWEEP's benchmark performance data from some of the utilities in the southwest region. SWEEP is a public interest organization promoting greater energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

5.2 UPAC Energy Vision Recommendation

In 2011, Colorado Springs Utilities adopted the following Energy Vision:

> *By 2020, Colorado Springs Utilities will provide 20 percent of its total electric energy through renewable sources, provide opportunities to achieve efficiencies with the goal of reducing average electric use by one percent each year through 2020, and maintain a 20 percent regional cost advantage.*

In 2014, the UPAC completed a year-long review of the Energy Vision. UPAC received information from Colorado Springs Utilities staff, outside experts, citizens, relevant research, publications and other sources. UPAC reviewed the intent of the EIRP, Colorado Renewable Energy Standard, and Colorado Springs Utilities' electric generation portfolio, particularly existing and potential renewable sources. UPAC considered regulatory and other external drivers, timeframes, short-term and long-term costs of different types of renewable energy, and customer preference. Through facilitated discussion, UPAC weighed the advantages and disadvantages of various Energy Vision options and alternatives and recommended the following revision to the Energy Vision:

> By 2020:
> *Colorado Springs Utilities will provide 20 percent of its total electric energy through renewable sources with one percent from distributed generation sources. Renewable energy goals will be achieved with a maximum bill impact of one percent.*
>
> *Colorado Springs Utilities will help customers reduce their electric energy use by 10 percent and reduce electric demand by 12 percent. Reduction goals will be achieved with a maximum bill impact of two percent.*

The UPAC Energy Vision recommendations were not approved prior to the EIRP, however the Utilities Board directed this Energy Vision recommendation be included in the analysis for potential adoption as part of the EIRP approved portfolio.

5.3 2015 DSM Potential Study

In 2015, Colorado Springs Utilities commissioned The Cadmus Group to perform a revised DSM Potential Study. The purpose of the study is to prepare a revised 20-year assessment of Technical, Economic and Achievable DSM Potential. The study will also outline program plans for program development and the data required to provide resource planning a more accurate assessment of energy and demand impacts from DSM programs. The new study includes substantial local primary research consisting of residential and commercial customer telephone surveys and on-site walkthroughs of selected commercial properties to assess local equipment saturations.

The EIRP concluded before the 2015 DSM Potential Study, so results from the new DSM Potential Study were not available in time for use in developing the EIRP scenarios. The new achievable DSM potential estimates will be compared to the selected DSM goals following the conclusion of the EIRP. The consideration that actual achievable potential may be lower than portfolio goals was addressed through a "development risk" factor assigned during the subjective, decision matrix portion of the portfolio evaluation process.

5.4 Electric DSM Inputs to the 2016 EIRP

Program performance through 2014 suggested that additional potential exists beyond what was forecast in 2009 DSM potential study, and that savings in the near term might be achieved at a lower cost than originally forecast. The results of the 2009 electric DSM Potential Study, the Colorado Springs Utilities Energy Vision, along with actual DSM program performance from 2011-2014 were used to develop the electric DSM scenarios. These were evaluated on an integrated basis with supply-side options in the 2016 EIRP. Because UPAC's recommended Energy Vision included placing a cap on DSM costs, a medium case incorporating the cost cap was included in the DSM inputs.

The following DSM inputs were developed and selected for use in the EIRP:

- High Case with cost cap
  - 12 percent energy reduction goal by 2020.
  - Cost capped at two percent of estimated revenue
  - Three percent distributed generation goal by 2020
- Medium Case
  - 10 percent energy reduction by 2020
  - One percent of incremental RE target from distributed generation
  - No cost cap
- Medium Case with cost cap
  - 10 percent energy reduction goal by 2020
  - Cost capped at two percent of estimated revenue
  - One percent distributed generation goal by 2020
- Low Case
  - 6 percent energy reduction by 2020.
  - One percent of incremental RE target from distributed generation
  - No Cost Cap

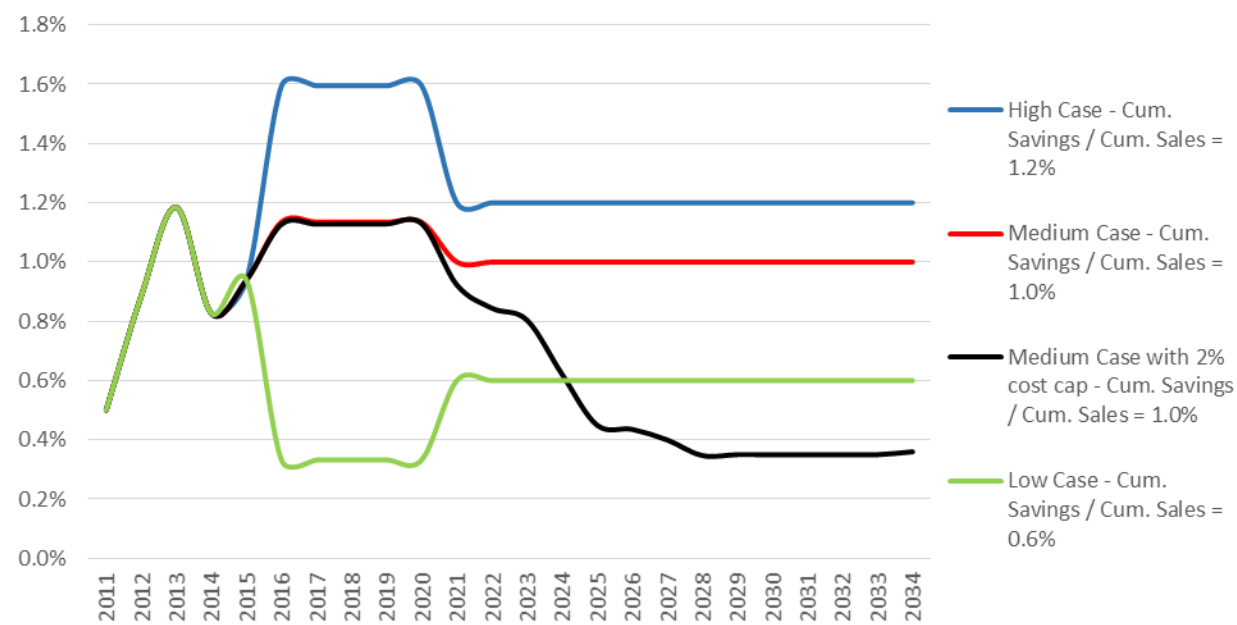
Though summarized in the list above as a percentage of electric retail sales in 2020, the DSM energy reduction goals are technically defined as an average of 1.2 percent, 1.0 percent and 0.6 percent reduction in electric retail sales each year through 2020. For the purpose of computing the cumulative 2020 goals, electric retail sales reductions begin in calendar year 2011. These annual percentages and cost assumptions were extended from 2021 to 2035 in order to obtain electric DSM savings targets for the next 10 years of the EIRP planning horizon. Residual savings from long lifetime measures were also included in years 2035-2045 to account for the persistent value of long-term savings from long lifetime energy efficiency programs. Average program lifetimes were incorporated into the inputs, so as not to include future naturally-occurring savings from baseline code and standard changes in the demand and energy reduction estimates that occur as equipment is replaced in future years when newer codes and standards are in effect.

For development of the inputs, program unit costs from 2014 were used to forecast near-term program costs, and unit cost estimates from the 2009 potential study were used for costs in later years, with interpolation of costs in intermediate years. Extrapolation of cost trends from the potential study were used where the new forecast exceeded the previous achievable potential estimates.

In addition to the overall savings values and program costs, seasonal hourly load shapes reflecting the cumulative effects of the expected mix of residential, commercial and industrial programs were generated for use in more accurately determining the energy and demand effects of the DSM programs.

Figure 5-1 depicts the savings as a percentage of sales from 2011 through 2034 for these four scenarios.

Figure 5-1: Annual percent reduction in electric retail energy sales for each scenario



The relatively large changes to 2016-2020 annual DSM levels in the high and low cases is a reflection of the relatively short remaining time for making changes to the cumulative Energy Vision 2020 achievement levels. At the board's direction, during the portfolio selection process a goal of 1.2 percent DSM/year with a two percent cost cap was ultimately selected. Although more aggressive than the "Medium Case with 2 percent cost cap", this goal is expected to be effectively very similar to the capped 10 percent case due to the cost constraint.

All DSM savings will be validated annually through a detailed measurement and verification process. In 2011, for example, DSM savings were estimated at 8.9 MW and 21,051 MWH. Savings are conservatively estimated because they are based only on the number of rebates paid and the estimated impact per rebate, or for equipment bought with incentives (such as CFL light bulbs). No savings are attributed to education or advertising programs. Colorado Springs Utilities also does not include savings from federal appliance efficiency standards or Energy Star programs unless rebates are paid when customers purchase of Energy Star appliances. Achieved DSM savings are part of management and executive goals, and are included on the scorecard for the chief executive officer.

6.0 Environmental and Regulatory Considerations

Colorado Springs Utilities is committed to environmental stewardship of all resources, and incorporated environmental considerations throughout the entire 2016 EIRP process. Inputs included unit emission rates, control costs, and CO2 regulation, incorporating feedback from the public process. Consideration was given to both known and future potential requirements in scenario and portfolio evaluation. In addition, the intangible decision matrix analysis included scoring the societal benefits of each portfolio, representing climate change, public health and overall aesthetics. The combination of environmental variables in the modeling and the decision matrix analysis provides a comprehensive review of the risks and costs associated with a wide range of possible futures.

6.1 Unit Emission Rates

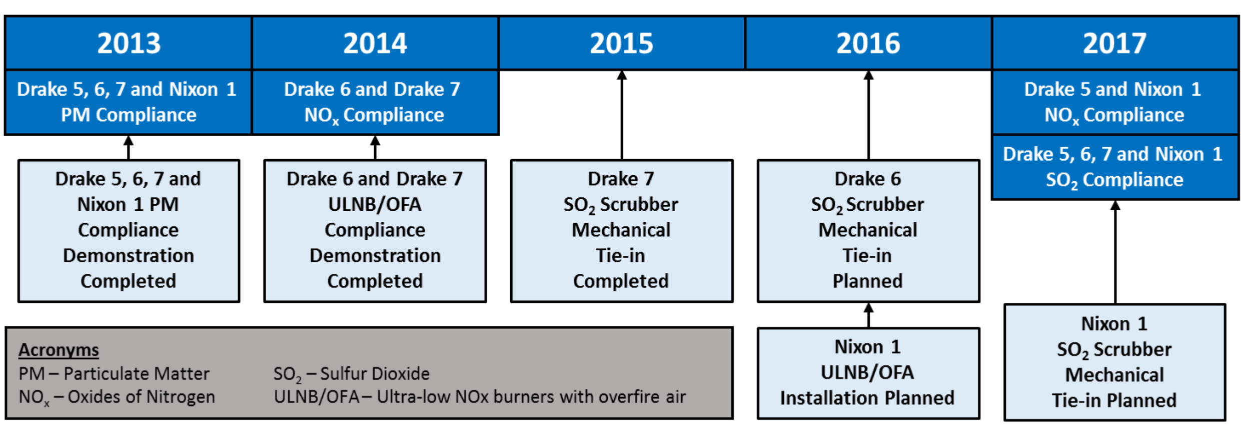
SO2, NOx and CO2 emissions were included as a modeled output in each of the 2016 EIRP scenarios and portfolios. Data sources for emission rates included recent Continuous Emissions Monitoring System (CEMS) data, Environmental Protection Agency (EPA) emission factors, future permit limits, and similar determinations for other sources. Units of measure were pounds per million British Thermal Unit (lb/MMBtu), which allowed changes to heat rate based on modeled dispatch to accurately reflect changes to emissions.

NOx, SO2, and CO2 emissions were included in the modeled output for comparative analysis of scenarios and portfolios. Certain scenarios or portfolios included CO2 emissions constraints, as detailed in section 6.3, Carbon Dioxide Regulation. Emissions were also included in the decision matrix analysis in two of the three facets of societal benefits. CO2 emissions were a surrogate for climate change, and were scored from zero to two points. SO2 and NOx emissions were a surrogate for public health, and were scored from one to three points.

6.2 Control Costs

Colorado Springs Utilities plans to comply with the Regional Haze State Implementation Plan (SIP), which requires statewide reductions of NOx and SO2 prior to Dec. 31, 2017 primarily through additional control or retirement of coal-fired electric generating units (EGUs). Figure 6-1 shows the Regional Haze implementation timeline and control projects for Colorado Springs Utilities' units.

Figure 6-1: Regional Haze implementation timeline



Note the timeline and projects shown in Figure 6-1 may change as a result of decisions in this EIRP.

The individual cost components that make up the assumption for O&M values for fixed and variable, non-labor and labor costs for environmental control equipment such as SO2 scrubbers, ultra-low NOx burners (ULNB) and mercury control were based on values used in the 2016-2020 budget, which was in the early stages of development at the time the EIRP values were finalized. These include known or projected values for items such as reagent use, water consumption, disposal cost, and auxiliary load.

Additional reductions of NOx could be required in the future based on several different ongoing regulatory processes, such as the 2015 lowering of the federal ozone National Ambient Air Quality Standard (NAAQS), the next step of Regional Haze, or the Rocky Mountain National Park Nitrogen Deposition. With the current implementation of ULNB for Regional Haze compliance reducing NOx on the combustion side of the equation, additional reductions would likely be in the form of post combustion control, such as Selective Catalytic Reduction (SCR) on coal-fired units.

The former URS Corporation, now known as AECOM, developed unit specific cost estimates inclusive of capital and O&M for SCR controls in 2009, and provided updates to these estimates in 2013. Specific timing of this potential requirement is not known, and could be influenced by the political climate, legal determinations, and what air quality improvements will be observed from emissions reductions associated with other current or future programs. Given this uncertainty, a range of potential requirements were included in scenarios. The majority of scenarios assumed all coal-fired units would require SCR control in 2023, three scenarios assumed SCR would not be required, and one scenario looked at staged implementation on the four coal-fired units from 2026 to 2028.

6.3 Carbon Dioxide Regulation

Carbon dioxide regulations can propel a shift from coal-fired generation to lower-emitting natural gas-fired generation or emission-free generation, such as solar, wind, hydropower and nuclear by establishing emission limits, trading programs or taxes. In June 2014, the EPA issued proposed rules intended to reduce carbon pollution from power plants, and to encourage increased use of lower carbon intensity resources. The CPP would apply to existing electric generating units, would require each state to develop a plan outlining strategies selected for a 10-year overall compliance period, with the first compliance year in 2020. The rule provided each state with several compliance options.

For the 2016 EIRP, Colorado Springs Utilities assumed that the proposed CPP would be implemented as a mass-based emissions limit. This type of limitation is easily and reliably included into the EIRP modeling and analysis tools. Additionally, other well-known programs, such as the Acid Rain Program, the Cross-State Air Pollution Rule, the Regional Greenhouse Gas Initiative, and California's Cap-and-Trade Program, rely on mass-based emissions limitations.

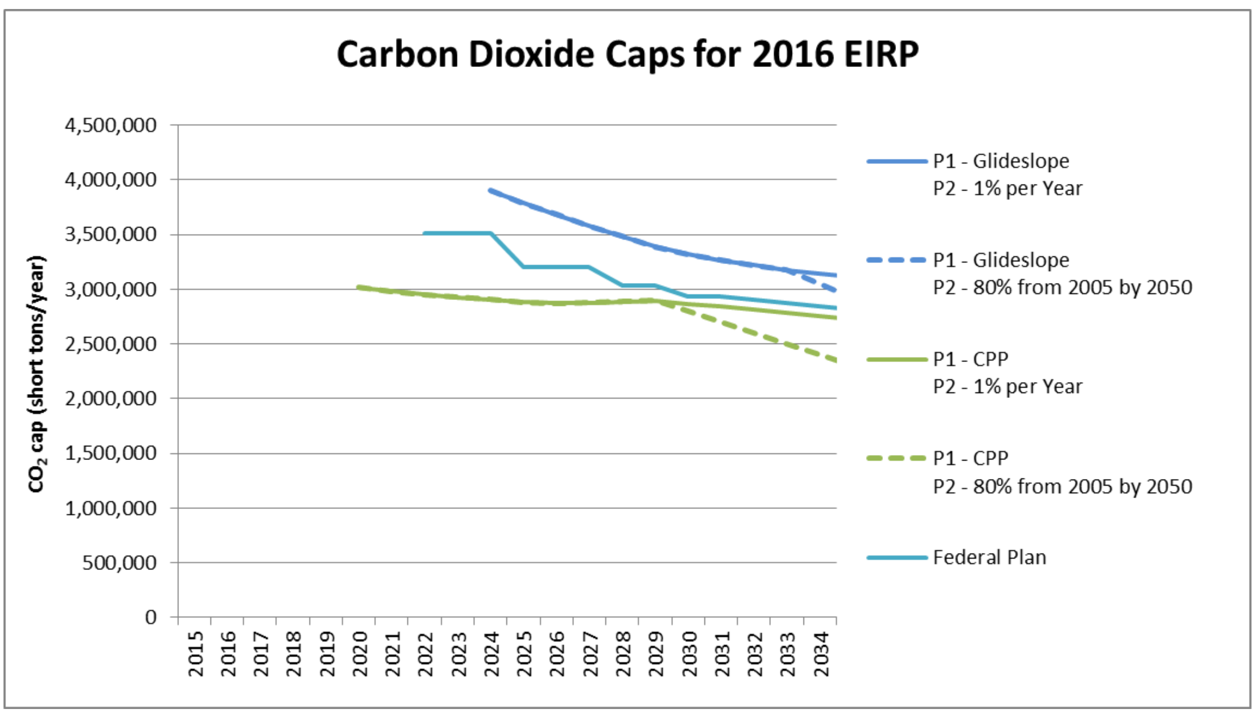
Initially, four potential CO2 mass emission caps were developed, as shown in Figure 6-2. Each cap had a Phase 1 component for a 10-year period based on the Proposed CPP, and a Phase 2 component for the remainder of the EIRP timeframe. The two options for Phase 1 were designated as CPP and Glideslope. The CPP caps used the year-by-year emission rate goals directly from the Proposed CPP for the state of Colorado, with a conversion to a mass cap using the 2015 Colorado Springs Utilities corporate load forecast. Glideslope caps were based on a more gradual implementation of the Proposed CPP rate goals for the state of Colorado, and also imposed a four year delay on implementation due to the contentious nature of the rule and likely litigation. The Proposed CPP did not provide for reductions after 10 years, but it was assumed there would be a second phase of the program. Phase 2 assumptions were either one percent reduction per year, or eighty percent reduction by 2050. The eighty percent by 2050 goal has been endorsed by numerous carbon reduction advocates, including the Obama-Biden comprehensive New Energy for America Plan. The one percent per year reduction is a less aggressive target. Sixteen scenarios included one of these four mass caps as a constraint.

In August 2015, EPA issued the CPP as a final rule, and proposed a Federal Plan with model trading rules to implement the CPP. One additional mass cap was developed for the 2016 EIRP based on the allocation method proposed in the Federal Plan for mass based compliance. There was no specific accounting for the Clean Energy Incentive Program or for any of the set-asides that are optional for states to adopt. In the event that Colorado did adopt one or more of the set-asides, the assumption is that Colorado Springs Utilities would acquire a pro-rata share of each set-aside.

This Federal Plan mass cap fell within the bookends of the initial four mass caps. Each of the final portfolios was subsequently run in two conditions; once with this federal CPP mass cap, and once without. One of the four components of each portfolio's score was the cost with the CPP, which was based on the revenue requirement 20-year net-present value (NPV) and comprised 25 percent of the overall score.

It should be noted that in February 2016 the United States Supreme Court stayed the CPP final rule. In Colorado, however, the State is continuing to evaluate CO2 emission reduction options. Colorado Springs Utilities will continue to evaluate potential impacts going forward at both the state and federal level relative to reduction plans and timeframes.

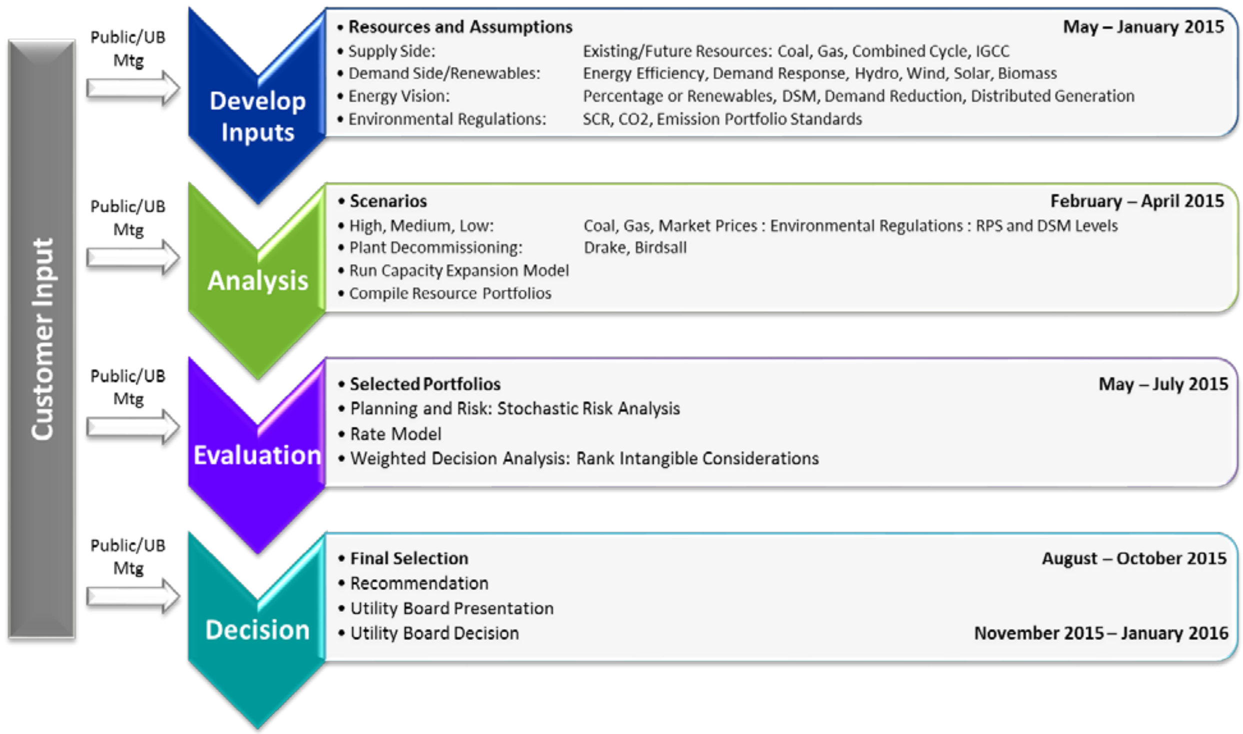
Figure 6-2: Carbon Dioxide Mass Caps for 2016 EIRP



7.0 Public Participation, Outreach, and Research

The 2016 EIRP process included a rigorous public outreach and participation program. Community conversations regarding the future of the Drake Power Plant were underway as the EIRP process began during the fall of 2014. As a result, the public process had a heightened awareness on carbon dioxide regulations from the EPA, renewable energy resources, DSM programs to provide customers with greater opportunities to reduce electric use, and customer-owned distributed energy resources. Figure 7-1 illustrates the EIRP process and public input at key milestones. Colorado Springs Utilities communicated to customers using newsletters, paid media, media interactions resulting in extensive news coverage, website postings and social media. Public participation included public meetings, presentations to community organizations, customer surveys and a Customer Advisory Group.

Figure 7-1: EIRP process and public input at key milestones



7.1 Public Meetings

Four public meetings were held as part of the EIRP process. At each of the four public meetings, the agenda was designed to capture public input relevant to each of the EIRP phases. These meetings were:

- Public Meeting One: Share critical assumptions, data collection and analysis to date, while obtaining public input on the planning process and identification and removal of any "gaps" before moving forward.
- Public Meeting Two: Share preliminary scenarios, present ranges of future values for different criteria, and explain the scenario-to-portfolio process. Obtain input to finalize and prioritize scenarios for further study.
- Public Meeting Three: Share results of scenario screening and portfolio development, leading to a final list of portfolios for consideration.

- Public Meeting Four: Share final preferred portfolios to be advanced to the Utilities Board for review and approval, and obtain comments on the portfolio to document the public's response and concerns. Additionally, a 30-day open comment period was held to capture comments on the preferred portfolios and recommended portfolios for the Board's consideration.

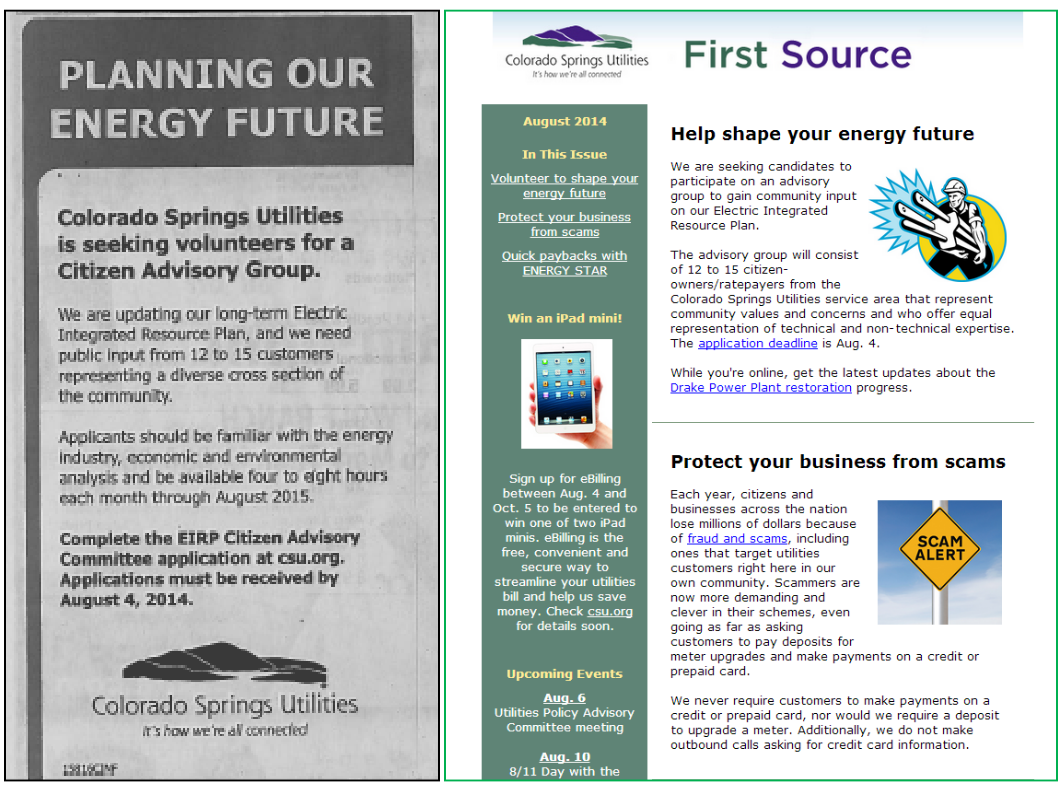
One result of direct public involvement was the creation of a 10th portfolio that was added after the third public meeting.

7.2 Customer Advisory Group

In addition to the public meetings, the CAG was formed as a way to obtain more extensive public input into the details of the EIRP process, as it was important to engage a representative group of community members as a part of the process. The advisory group is a forum for bringing the public's ideas, issues, and concerns into the planning process. Functionally, the advisory group is designed to lead the discussion on stakeholder interests and make recommendations to the EIRP project team to help ensure the plan reflects the concerns of all potential interests; that the process has helped create an informed public; and the plan will have informed decision makers. The advisory group promotes a collaborative effort between Colorado Springs Utilities and its citizen-owners.

To solicit applicants, an invitation was sent to previous EIRP stakeholders and other community/ business groups. In addition, a press release was issued on July 22, 2014; information was posted on the Colorado Springs Utilities website, its business newsletter First Source, and social media; and an ad was placed in the Gazette four times between July 20 and August 3, 2014. Figure 7-2 shows examples of such advertisements.

Figure 7-2: Advertisements to recruit members to the Customer Advisory Group



Application questions were designed to assess an applicant's knowledge base, interest, ability to solve problems within a group and community sector representation. The key for selection was ensuring a diversity of opinions was reflected within the group. The CAG was culled from 33 applicants and then assessed and scored on established criteria by an internal selection committee. The committee then made recommendations to Utilities Board-appointed review team, which approved of its membership.

The CAG was comprised of both large industrial and mid-size businesses, the University of Colorado at Colorado Springs, several small businesses, two local military installations, and five residential customers (note that some of the other representatives were also residential customers).

The CAG had 17 meetings and participated in every aspect of the EIRP process from October 2014 to September 2015. The first phase of the CAG process centered on introducing and educating the members to the overall EIRP process and reviewing input data. Phase Two focused on scenarios and different potential futures the CAG felt should be considered as part of the planning process, and during Phase Three the CAG reviewed nine candidate portfolios that were the result of scenario modeling and then identified a potential tenth which was later added at the third public meeting. Finally, the CAG was extensively involved in the development of evaluation criteria and weighting, the intangible decision analysis weighting and scoring, and ultimately the portfolio recommendation to the Utilities Board.

7.3 Customer Surveys

Colorado Springs Utilities' Customer Experience Department has developed several surveys to gauge customer preferences and price sensitivities regarding different energy options since 2011. The latest survey results were compared with previous ones to review trends in customers' preferences. Conducted in November 2014 and March 2015, the random surveys were designed to evaluate customer willingness to pay for additional renewable resources in the supply mix; determine customer opinion on how Colorado Springs Utilities should invest in electricity sources; and to address specific questions raised by CAG and EIRP team through planning sessions. The November study involved phone interviews of a random sampling of 635 residential and 270 business customers. The March sample included 350 residents and 141 business customers surveyed electronically who are subscribers to the First Source electronic newsletter.

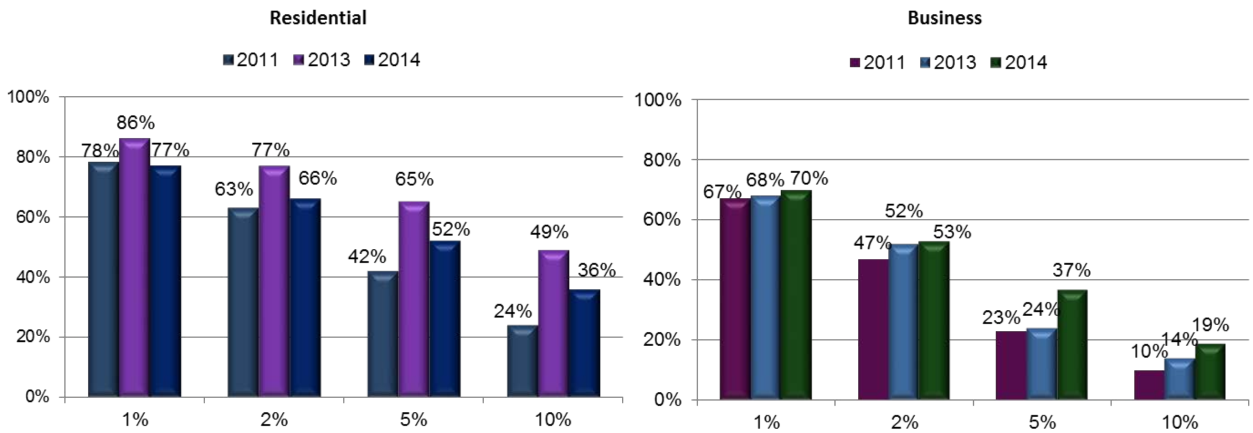
Survey Results

In all classes of customers, including the largest commercial class, the majority expressed an interest in increasing renewable energy in the supply mix, even if it would increase the customers' bill. The survey results are summarized in Figure 7-3 and Figure 7-4. Complete survey results can be found in Appendix B. The majority of residential and commercial customers indicated they were willing to pay higher rates if the percent increase in the bill was one percent or less, with residential support as high as an additional two percent. This result is consistent with historical EIRP surveys.

The willingness-to-pay question was asked in phone surveys to both residential and business customers as follows:

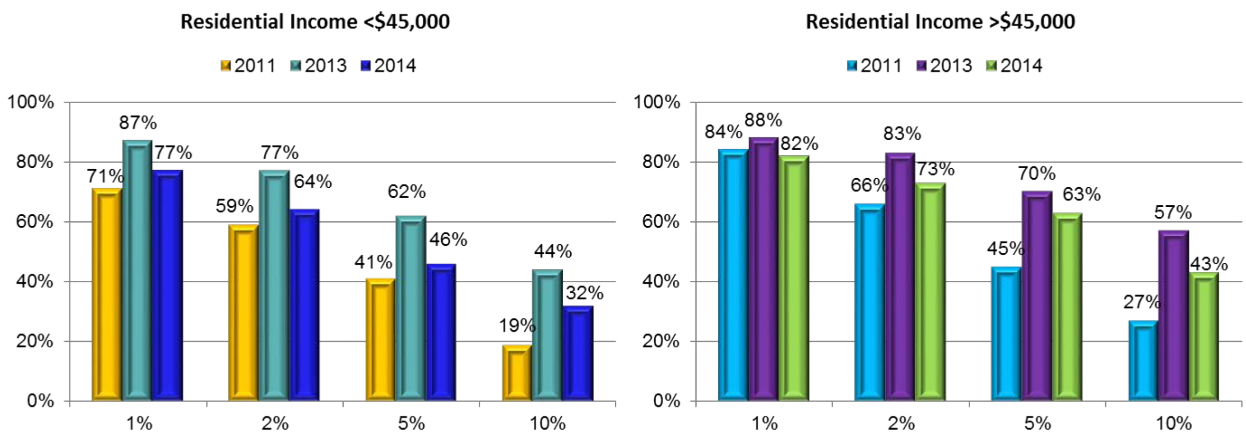
Would you be willing to pay __% more per month for electricity to cover any increased cost to provide renewable energy? So if your electric bill is $50/$75/$100, the increased cost would be $___ (Dollar value based on 1%/2%/5%/10%) ($50/$75/$100 amount piped in depending on answer in previous question)

Figure 7-3: Residential and business customer willingness to pay extra for renewable energy as a percent of total bill



Residential: ± 3.88 confidence interval
Business: ± 5.93 confidence interval

Figure 7-4: Residential customer willingness to pay extra for renewable energy as a percent of total bill by income level



Residential: +/- 3.88 confidence interval

Survey results were incorporated into the EIRP evaluation as part of the intangible criteria review under the category “Customer Resource Preference”. Portfolios that pursued renewable energy within a one percent bill impact and DSM were scored higher given the preference shown in these surveys.

7.4 Public Outreach Summary

Determining the overall sentiment of a community on any given project or plan is challenging. Attention must be paid to reaching customers in an inclusive manner, so that all voices are given an opportunity to participate. Public outreach focuses on engaging the unengaged by offering multiple avenues in which to participate, whether through public meetings, presentations to community organizations, customer surveys, our website, social media, or the EIRP Customer Advisory Group.

Technical analysis reflects public input and other ancillary community efforts, such as the Pikes Peak Regional Sustainability Plan’s renewable energy goal of 50 percent by 2030 as one scenario. Other examples of the impact of the public process are the inclusion of a new coal unit as a potential future resource, small modular nuclear reactors as a potential future resource, and the addition of a tenth portfolio for consideration with no coal.

Ultimately, three portfolios were given preference by scoring and vetted through CAG discussions. While the CAG could not all support a single portfolio, ultimately they agreed at their last public meeting to recommend Portfolio D to the Utilities Board with three options for Drake 5. Those options are to operate Drake 5 with only natural gas after December 2017; to mothball the unit for up to three years starting in 2015 or 2016 (with the potential to restart it within the three years as a natural gas unit); or decommission the Unit no later than December 2017.

A summary of Colorado Springs Utilities EIRP public involvement is shown below:

- Four public meetings: Dec. 4, 2014, and April 9, July 30, and Sept. 29, 2015.
- Five Utilities Board Strategic Planning Committee meetings: Nov. 12, 2014, and Feb. 11, May 13, Aug. 13, and Oct. 15, 2015.
- Nine Utilities Board meetings: Dec. 17, 2014; Feb. 18, May 20, June 15, Aug. 19, Oct. 21, Nov. 18, Dec. 16, 2015; and Jan. 20, 2016.
- Seventeen CAG meetings: Monthly meetings beginning Oct. 1, 2014, through Sept. 17, 2015, with an extra meeting in each of five months.
- Mass media: CAG recruitment and public meetings in local print and electronic media.
- Electronic communications through an e-mail newsletter, website, and social media.
- Six community presentations and presence at two Utilities Board member open houses.
- Customer surveys: November 2014 and March 2015.

In addition to the specific examples of customer input in the EIRP above, the following customer input themes were seen consistently throughout all aspects of the public process:

- Ensure the impact of the EPA's CPP is considered.
- Consider impacts of distributed generation.
- Consider the impact of flat to declining load.
- Investigate the interrelationship between water and energy.
- Illustrate the impacts of health and other social factors.
- Increase energy literacy in the community.
- Investigate running Drake with natural gas.
- Investigate and monitor emerging technologies.
- Consider using a 30 year planning horizon.
- DSM programs are valued.

An example of customer feedback from the second public meeting is shown in Appendix C.

The recent public process reflects the trends in public opinion have not changed significantly in the past few years. Customers prefer having renewable energy resources, with cost as the final determining factor. Customers still value energy efficiency programs as a means to reduce load and save on their overall bills. However, there is more awareness about changes in the industry including the increases in distributed generation nationwide, the possibility of storage contributing to the energy portfolio, and flat to declining demand for energy trends. There was a desire, especially from the CAG, to see Colorado Springs Utilities partner with their customers as these changes take place over the coming years.

8.0 Scenarios and Portfolio Development

After all the assumptions and input data is gathered, the EIRP process analyzes different possible futures, also called scenarios, and develops candidate portfolios based on the results of the scenario modeling. Each scenario results in different portfolio configurations and possibilities for the future electric supply of Colorado Springs Utilities. Portfolios can also be manually constructed if there are specific resources our customers want or reject in the resource mix. A wide evaluation of different scenarios helps ensure we can recommend a portfolio of resources that provides a balanced and responsible plan, which meets reliability requirements, is fiscally sound, promotes environmental stewardship, is flexible, and balances risk and cost.

To this end, the EIRP examines scenarios under multiple combinations of varying conditions such as future load, fuel costs, renewable resources, and environmental regulations. The EIRP modeling and analysis process is shown in Figure 8-1. As shown in sections 2.0 through 6.0 of this report, the EIRP process develops assumptions for key factors, such as load growth and fuel prices, including a set of base assumptions and a reasonable range around the base.

Scenarios are developed that combine alternative values including load growth, DSM, renewable resources, additional emissions requirements, carbon dioxide regulation, natural gas prices, wholesale electric market prices, and coal prices. These scenarios are evaluated using the ABB System Optimizer capacity expansion model. The model identifies the mix of existing and future resources that results in the lowest cost to meet projected load and the other input assumptions for each scenario. The capacity expansion plans resulting from the scenarios evaluated are consolidated into a smaller number of resource portfolios. Evaluation of those portfolios and ultimately the selection of a single preferred portfolio is discussed more in section 9.0 of this report.

Figure 8-1: Portfolio development process

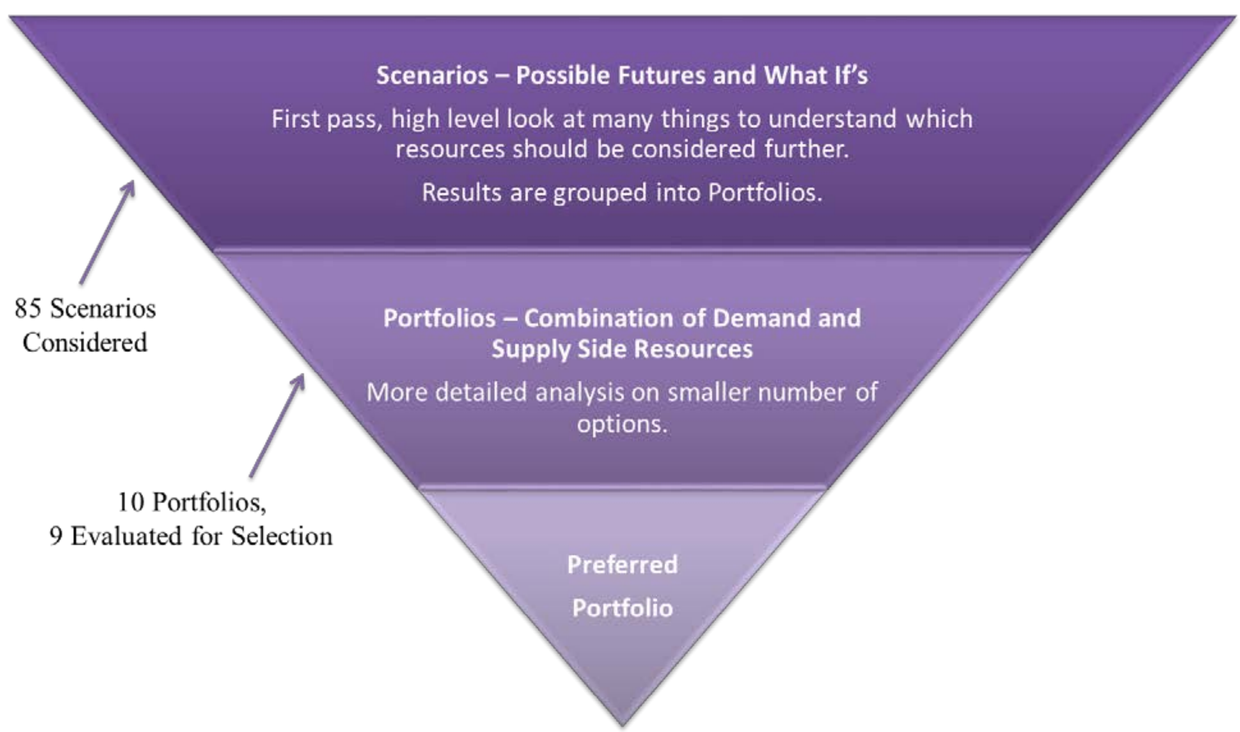


ABB Models Used in the EIRP Analysis
The ABB System Optimizer develops the least cost capacity expansion plan over a long-term horizon. System Optimizer provides answers to key portfolio investment decisions such as type, timing, and size of resource additions and retirements given reserve margin requirements. In addition, the model accounts for DSM and RES requirements. A mixed integer programming algorithm is employed to identify the least-cost expansion plan.

The ABB Planning and Risk Model uses the optimal expansion plan from System Optimizer. Planning and Risk (PaR) is a production cost model which finds the least-cost hourly solution balancing given the resources and load obligations. PaR develops detailed, hour-by-hour estimates of generation, fuel burn, emissions, and costs. The hourly production cost modeling provides more detailed costs than those from System Optimizer. PaR uses detailed generator attributes, such as multi-point heat rate curves, ramp rates, minimum up and minimum down times, start costs, O&M costs, etc.

8.1 Scenarios

Colorado Springs Utilities evaluated multiple scenarios that examine how the current mix of coal, natural gas, and hydro-powered generation could be combined with renewable energy, DSM, and possible future resource additions. These scenarios considered different future loads, fuel costs, market costs, renewable standards, DSM programs, levels of distributed generation, environmental regulations, and decommissioning dates for existing generating units including those at Drake and Birdsall. Scenarios regarding Drake unit decommissioning dates are based on input from both the Utilities Board and the public.

The EIRP analysis evaluated 85 scenarios using the ABB models which are detailed in Appendix D. The highlights in blue on the table show changes from the reference case. The reference case parameters were determined by the Utilities Board or represent the middle of forecasted values. The column "Portfolio" shows which portfolio was created as a result of that scenario or a combination of scenarios that had similar results. When scenarios produce the same or very similar results, it indicates the resulting portfolio could be a great solution in a number of varying futures.

Under the expected demand forecast, Colorado Springs Utilities does not need to install new, firm generating capacity for many years. Much of the efforts in the EIRP involved examining other requirements, such as decommissioning units or adding renewable energy. The EIRP also examined how the need for new generating capacity could change with fluctuations in the demand forecast, DSM, environmental factors and fuel costs.

In addition to creating a foundation for portfolio development, scenario analysis can also be used to isolate individual variables and observe any cost or resource changes as a result of a single input. Some scenarios were specifically designed to isolate triggering events and to better understand what is driving the results in the expansion plans. Others were designed to determine the incremental cost of increasing renewable energy or to determine the value of DSM.

DSM: Figure 8-2 shows the results of scenarios 1 and 12-15 compared to scenario 16, without any DSM. It shows the DSM level with the highest benefit-to-cost ratio is 10 percent with a two percent spending cap. For every dollar spent on DSM, there would be $1.80 in benefits through avoiding fuel spending and deferring new capacity expansion. Additionally, all levels are more cost-effective than doing no DSM at all except the full 15 percent by 2020 and 1.5 percent per year thereafter.

Figure 8-2: Benefit to cost ratio of increasing levels of DSM

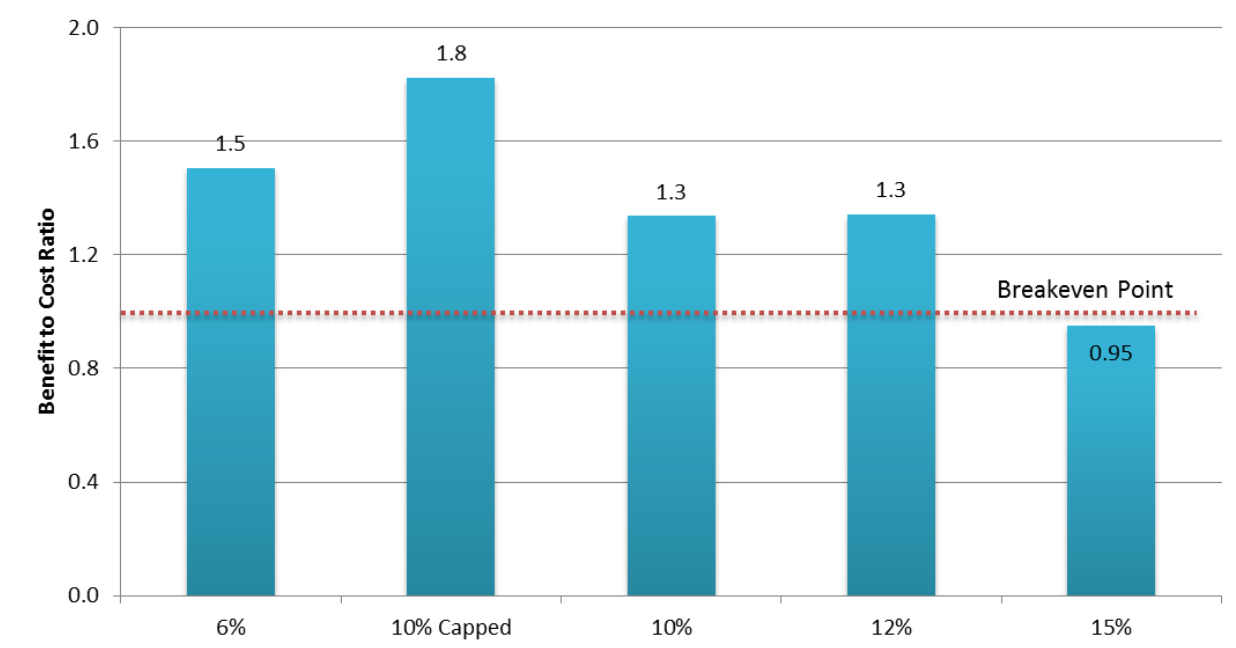
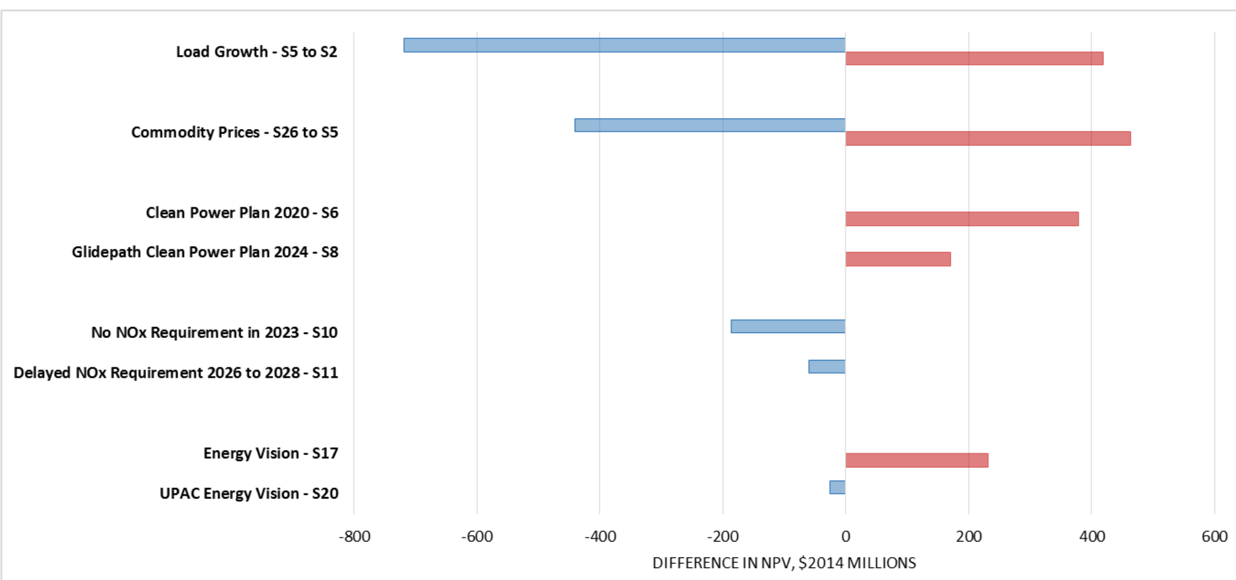


Figure 8-3 shows how sensitive the cost of the portfolio is to key individual changes made to the reference case. Note the portfolio is most sensitive to the load forecast, then to commodity prices, and the CPP. Sensitivity as a percent can be calculated by dividing the difference in NPV by $6,734, the reference case NPV in millions. For example, the reference case included a new NOx reduction requirement in 2023 for all four coal units which was compared to no new NOx requirement showing it increases the cost of the portfolio by $187 million over 20 years, or 2.8 percent.

Figure 8-3: Individual input sensitivity to 20-year NPV, scenario number(s) are noted for reference



8.2 Portfolios

Once scenario modeling is complete, a smaller set of distinct, representative portfolios are developed which capture various expansion plans and decommissioning options. Scenario results often produce similar expansion plans even though the inputs can be very different. For example, a scenario that includes a CO2 regulation might produce an expansion plan with new solar capacity—a similar result to another scenario that might include a higher demand load forecast and no CO2 regulation.

Originally nine portfolios were identified and presented to the public for consideration, but after receiving feedback at the third public meeting, a 10th, Portfolio J, was added which removes coal completely. Figure 8-4 shows the decisions that would be made for each of the portfolio options and the resulting resource fuel mix in 2025. A larger version of this graphic can be found in Appendix E. Figure 8-5 and Figure 8-6 show the resulting expansion plans for these decisions.

Portfolio A – Low DSM, All Units Stay Online
This portfolio is the reference case expansion plan, keeping all three Drake units online. It includes some modest renewable acquisition in the mid-2020's to meet the minimum 10 percent CO RES.

Portfolio B – Birdsall Decommissioning
This portfolio removes 55 MW at Birdsall in 2018 while keeping all Drake units online. It includes an additional DSM resource in 2021 and additional solar capacity in the early 2030's.

Portfolio C – Low DSM, Drake 5 to Natural Gas Only
Similar to Portfolio A, this option discontinues coal operation on Drake 5 after 2017.

Portfolio D – UPAC Energy Vision, Drake 5 to Natural Gas Only
Similar to Portfolio C, this option increases DSM and renewables by 2020 for the UPAC Energy Vision resulting in up to 80 MW of solar by 2020 (as long as it stays within a one percent cap).

Portfolio E – High DSM, Drake 5 to Natural Gas, and Birdsall Decommission
This option has Birdsall decommissioning, plus high DSM, resulting in virtually no new resource acquisition for 20 years. It represents many of the low, flat, and declining load scenarios.

Portfolio F – Medium DSM with a Spending Cap, Drake 5 Decommissioning by 2018
This portfolio would have the most economic level of DSM and new renewables in the late 2020s.

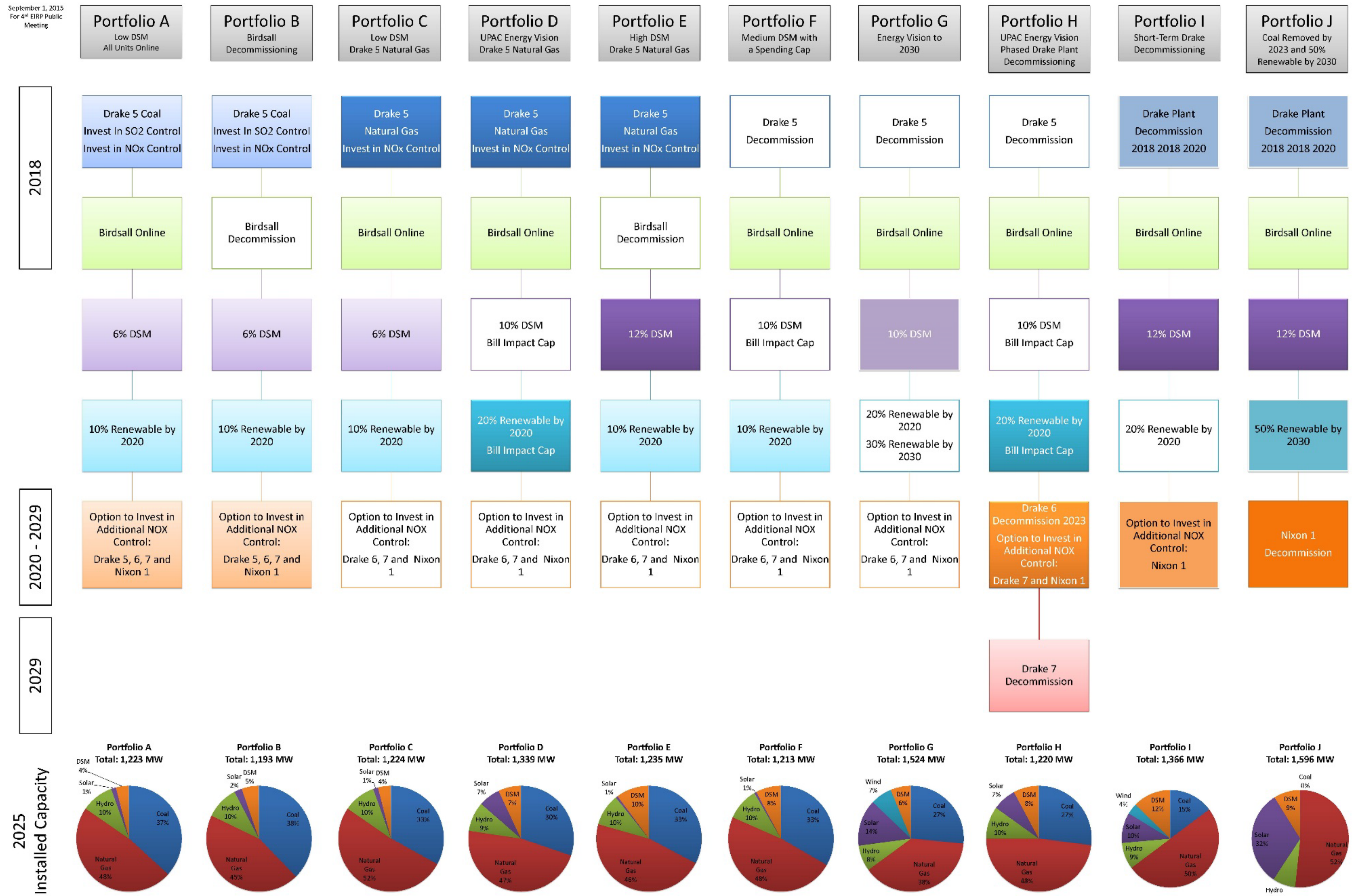
Portfolio G – Energy Vision to 2030, Drake 5 Decommissioning by 2018
This portfolio includes large renewable acquisitions leading up to 2020 and in the 2020's.

Portfolio H – UPAC Energy Vision, Phased Drake Plant Decommissioning by 2029
Similar to Portfolio D, this option has Drake 6 decommissioned in 2023 and Drake 7 in 2029. The portfolio represents many of the results of CPP scenarios.

Portfolio I – Short-Term Drake Plant Decommissioning by 2020
This portfolio includes Drake plant decommissioning by 2020 and high DSM without a spending cap. New solar, peaking natural gas, and DSM resources are added to replace Drake's capacity.

Portfolio J – All Coal Decommissioned by 2023, 50 Percent Renewable by 2030
In this case, the Drake plant would be decommissioned by 2020, Nixon 1 by 2023, and a new 240 MW natural gas combined-cycle plant would be added in 2023 with substantial renewable energy additions.

Figure 8-4: Candidate portfolios A through J decision tree and 2025 resource mix by fuel type



Portfolio expansion plans detail which new resource acquisitions are within each portfolio. Each portfolio, except I and J, has a secondary path triggered by the CPP which shows how resource acquisition would change under that regulation after 2020. Those new resources are shown in the light blue columns in Figure 8-5 and Figure 8-6.

Figure 8-5: Expansion plans for Portfolio A through Portfolio D

	Portfolio A		Portfolio B		Portfolio C		Portfolio D	
2016								
2017								
2018								
2019							Solar - 40 MW	
2020			Biogas - 1.7 MW				Solar - 40 MW	
2021		FRPP Uprate - 25 MW	CVR - 18 MW	FRPP Uprate - 25 MW CVR - 18 MW				
2022								
2023		Solar - 40 MW DR - 1.9 MW Storage - 8 MW CVR - 18 MW Biogas - 1.7 MW		Solar - 20 MW DR - 1.9 MW		Solar - 20 MW CVR - 18 MW Biogas - 1.7 MW		
2024		Solar - 10 MW DR - 1.9 MW		Solar - 10 MW DR - 1.9 MW	Biogas - 1.7 MW	Solar - 10 MW DR - 1.9 MW		
2025	Solar - 10 MW Biogas - 1.7 MW	DR - 1.9 MW	Solar - 20 MW	Solar - 10 MW	Solar - 10 MW	Solar - 10 MW	Biogas - 1.7 MW	
2026	Solar - 40 MW	Solar - 10 MW	Solar - 40 MW	Solar - 10 MW	Solar - 40 MW	Solar - 10 MW		DR - 1.9 MW Biogas - 1.7 MW
2027		Solar - 10 MW				Solar - 10 MW		DR - 1.9 MW
2028		Solar - 20 MW		Solar - 10 MW	Solar - 10 MW	Solar - 10 MW		DR - 1.9 MW
2029	Solar - 10 MW			Solar - 10 MW		Solar - 10 MW		DR - 1.9 MW CVR - 18 MW
2030		Solar - 10 MW	DR - 1.9 MW	Solar - 10 MW		Solar - 10 MW		DR - 1.9 MW
2031		Solar - 20 MW	DR - 1.9 MW	Solar - 20 MW		Solar - 20 MW		Solar - 30 MW
2032		Solar - 10 MW	Solar - 20 MW DR - 1.9 MW	Solar - 10 MW		Solar - 10 MW		Solar - 20 MW
2033		Solar - 30 MW	Solar - 10 MW DR - 1.9 MW	Solar - 20 MW		Solar - 20 MW		Solar - 20 MW DR - 1.9 MW
2034		Solar - 10 MW	Solar - 10 MW DR - 1.9 MW	Solar - 40 MW		Solar - 20 MW DR - 1.9 MW	DR - 1.9 MW CVR - 18 MW	Solar - 20 MW DR - 1.9 MW Storage - 2 MW
2035	CVR - 18 MW	Solar - 40 MW	Solar - 30 MW	Solar - 40 MW DR - 1.9 MW	CVR - 18 MW	Solar - 40 MW DR - 1.9 MW	Solar - 10 MW DR - 1.9 MW	Solar - 40 MW

CVR: Conservation Voltage Reduction DR: Demand Response (Air-conditioning load cycling)

FRPP: Front Range Power Plant

Figure 8-6: Expansion plans for Portfolio E through Portfolio J

	Portfolio E		Portfolio F		Portfolio G		Portfolio H		Portfolio I	Portfolio J
2016									DR - 1.9 MW	
2017									Solar - 10 MW DR - 1.9 MW	
2018					Solar - 30 MW				Solar - 40 MW DR - 1.9 MW	Solar - 50 MW
2019					Wind - 50 MW Solar - 40 MW		Solar - 40 MW		Solar - 40 MW DR - 1.9 MW	Solar - 80 MW
2020					Wind - 50 MW Solar - 40 MW Biogas - 1.7 MW		Solar - 40 MW		Wind - 50 MW Solar - 40 MW DR - 1.9 MW CT_DF - 72 MW FRPP Uprate - 25 MW CVR - 18 MW Biogas - 1.7 MW	Solar - 80 MW DR - 1.9 MW CVR - 18 MW Biogas - 1.7 MW
2021										Solar - 40 MW Solar - 20 MW
2022	Biogas - 1.7 MW	Biogas - 1.7 MW								Solar - 60 MW
2023		CVR - 18 MW		Solar - 10 MW DR - 1.9 MW CVR - 18 MW Biogas - 1.7 MW	Solar - 20 MW	Solar - 20 MW	Biogas - 1.7 MW			Solar - 60 MW NGCC - 240 MW
2024				DR - 1.9 MW	Solar - 40 MW	Solar - 40 MW				Solar - 50 MW
2025			Biogas - 1.7 MW	Solar - 10 MW DR - 1.9 MW	Solar - 40 MW	Solar - 40 MW	DR - 1.9 MW			Solar - 60 MW
2026				Solar - 30 MW			DR - 1.9 MW	Biogas - 1.7 MW	Solar - 10 MW	Solar - 60 MW
2027			Solar - 30 MW	Solar - 30 MW			DR - 1.9 MW CVR - 18 MW	CVR - 18 MW		Solar - 60 MW
2028			Solar - 20 MW	Solar - 30 MW			Solar - 20 MW DR - 1.9 MW	Solar - 30 MW DR - 1.9 MW		Wind - 50 MW
2029		Solar - 10 MW		Solar - 30 MW			NGCC - 240 MW	Solar - 30 MW DR - 1.9 MW		
2030		Solar - 10 MW DR - 1.9 MW	DR - 1.9 MW CVR - 18 MW	Solar - 30 MW DR - 1.9 MW	Wind - 50 MW Solar - 20 MW	Wind - 50 MW Solar - 20 MW		Solar - 30 MW DR - 1.9 MW		Wind - 50 MW Solar - 30 MW
2031		Solar - 20 MW	Solar - 30 MW DR - 1.9 MW	Solar - 30 MW				Solar - 30 MW DR - 1.9 MW		
2032		Solar - 10 MW	Solar - 20 MW DR - 1.9 MW	Solar - 20 MW DR - 1.9 MW				Solar - 20 MW DR - 1.9 MW		
2033		Solar - 10 MW	Solar - 20 MW DR - 1.9 MW	Solar - 20 MW DR - 1.9 MW		DR - 1.9 MW		Solar - 20 MW DR - 1.9 MW		DR - 1.9 MW
2034		Solar - 40 MW DR - 1.9 MW	Solar - 20 MW	Solar - 10 MW DR - 1.9 MW		DR - 1.9 MW		Solar - 10 MW DR - 1.9 MW		DR - 1.9 MW
2035	Solar - 10 MW	Solar - 40 MW DR - 1.9 MW	Solar - 30 MW	CT_DF - 36 MW		DR - 1.9 MW		DR - 1.9 MW CT_DF - 36 MW		DR - 1.9 MW

CVR: Conservation Voltage Reduction DR: Demand Response (Air-conditioning load cycling)

FRPP: Front Range Power Plant CT_DF: Dual Fuel Combustion Turbine

NGCC: Natural Gas Combined-Cycle

9.0 Evaluation of Portfolios

Each candidate portfolio was evaluated based on four metrics to get to a single preferred portfolio, with the exception of Portfolio J, which had much higher costs and was eliminated without scoring the other metrics. The evaluation methodology was developed with the CAG. Sensitivities to metric weighting was also tested based on customer input. Figure 9-1 shows a summary of the evaluation.

Figure 9-1: Portfolio evaluation summary

Metric		Unit	Definition	Weight
Cost without CPP		NPV of Revenue Requirement $Millions	Cost of the portfolio assuming the world as it primarily exists in 2015.	40%
Cost with CPP Best Estimate for Colorado Springs Utilities Pending State Plan		NPV of Revenue Requirement $Millions	Cost of the portfolio assuming the CPP begins in 2022, allowing resource adjustments after 2022.	25%
Financial Risk		95th Percentile NPV of Revenue Requirement $Millions	Cost of the portfolio at high natural gas prices, market prices, and demand based on historical volatility.	25%
Intangible Considerations	Dispatchability	Weighted Decision Matrix Score	Maximize ability to call on a resource when needed	10%
	Portfolio Diversity		Maximize smaller units, geographic spacing and different fuels	
	Customer Resource Preference		Majority of customers prefer investment in certain types of resources	
	Development Risk		Maximize ability to permit, meet schedule, secure funding, estimate resource cost, and obtain resource	
	Transmission Reliance		Minimize reliance on transmission	
	Societal Benefits		Maximize city image, minimize negative health and societal impacts	

Each scoring metric was based on a 100 point scale rounded to the nearest whole number. For the first three metrics, the least cost portfolio was given the full 100 points. For the fourth metric, the highest decision matrix score was given 100 points. Ten points was then deducted for each percent difference in metric value for the remaining portfolios. To avoid negative scores, if the total percent difference between the high and low exceeds 10 percent, ten points will be deducted for every two percent difference, three percent difference, etc.

The final portfolio scoring was designed to ensure adequate separation without forcing a high and low score. This method improves upon ranking by acknowledging similar values should be scored similarly.

9.1 Cost Analysis – With and Without Clean Power Plan

Each of 10 portfolios were simulated in ABB's Planning and Risk, a production cost model, to determine the projected fuel, operating and maintenance costs. These costs were combined with future capital cost requirements for each portfolio from the capacity expansion model, ABB's System Optimizer, and run through a financial model to produce a projected net revenue requirement for each portfolio. Annual net revenue requirements were developed for two cases: with and without the EPA CPP. Then the NPV from 2015-2034 was calculated for each revenue requirement.

The relative percent difference between each portfolio's revenue requirement is an appropriate estimation of average cost impact to our customers. The percent difference in revenue requirement is a systematic and rational approach to determine the average rate impact across all rate classes.

With CPP results are meant to quantify the regulatory risk of each portfolio. That is, if we were to select that portfolio, would we be putting ourselves in a position to end up paying higher costs later if the CPP is implemented as in the final rule released Oct. 23, 2015? In this respect, portfolios that are more flexible and proactive with CO2 reductions could have lower risk. However, even if a portfolio is selected today that isn't ideal under the CPP, it doesn't preclude utilities from taking steps later to adapt to the CPP. To account for this, only the first five years of the portfolios were locked down as a result of this EIRP and each portfolio was allowed to re-optimize past that with new resources for the CPP.

The results for both cost with and without the CPP are shown in Table 9-1. While scoring shows each portfolio's percent difference relative to the other portfolios within that metric, the table also provides values that show the incremental cost of the CPP. For example, Portfolio A shows an increased NPV of $233 million dollars, or about 3.7 percent, as a result of the CPP. On the other hand, Portfolios H, I and J show no increase as a result of the CPP because many of the building blocks for CO2 reduction were inherent in those portfolios.

Table 9-1: Portfolio cost results

Portfolio	Without Clean Power Plan				With Clean Power Plan			
	20-yr NPV $Millions	Percent Difference	EIRP Score	Rank	20-yr NPV $Millions	Percent Difference	EIRP Score	Rank
A	$6,316	1.0%	90	5	$6,549	2.0%	80	6
B	$6,330	1.2%	88	6	$6,574	2.4%	76	7
C	$6,298	0.7%	93	4	$6,492	1.1%	89	5
D	$6,264	0.1%	99	2	$6,440	0.3%	97	2
E	$6,255	0.0%	100	1	$6,419	0.0%	100	1
F	$6,271	0.3%	97	3	$6,455	0.6%	94	3
G	$6,751	7.9%	21	9	$6,848	6.7%	33	9
H	$6,486	3.7%	63	7	$6,472	0.8%	92	4
I	$6,687	6.9%	31	8	$6,687	4.2%	58	8
J	$7,589	21.3%	Not Scored		$7,589	18.2%	Not Scored	

Figure 9-2 and Figure 9-3 show the relative difference of each portfolio compared to Portfolio A. At the beginning of the EIRP, the Utilities Board established a reference case of 6 percent DSM and 10 percent renewable which is represented in Portfolio A.

There are several portfolios that show a negative difference. That does not necessarily forecast rate decreases, it just indicates which portfolios would be lower cost than Portfolio A would have been.

Only one portfolio showed enough sensitivity to the CPP to go from being a more costly portfolio than A, to a lower cost portfolio than A under the CPP—Portfolio H.

Figure 9-2: Relative difference in revenue requirement with and without CPP as a percent difference

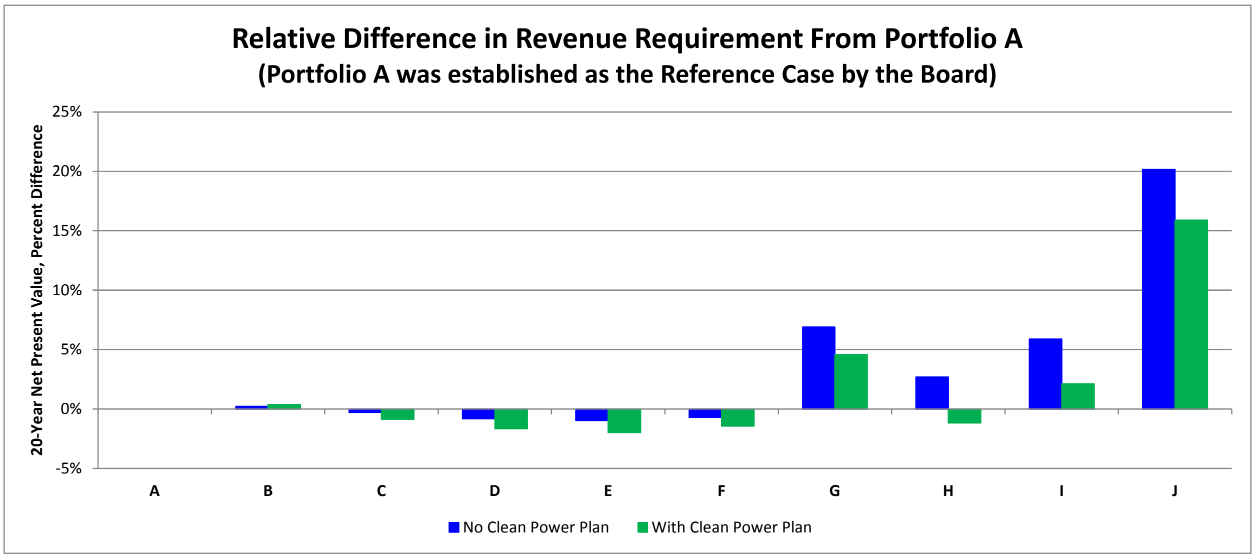
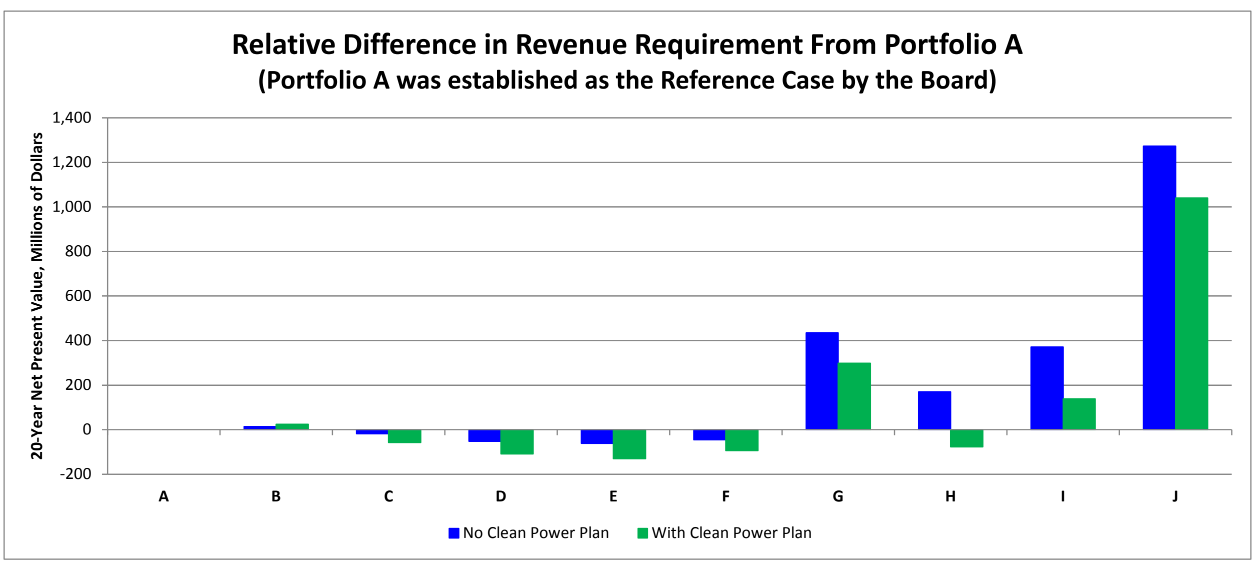


Figure 9-3: Relative difference in revenue requirement with and without CPP in millions of dollars



9.2 Financial Risk Analysis

For Portfolios A through I, financial risk was analyzed to identify which portfolios had the highest potential to cost more under likely input variations. Several inputs into IRP modeling can be volatile and difficult to forecast, especially natural gas prices. While a portfolio could have an attractive cost at the expected input values, there is some risk that the same portfolio will not look as financially attractive if those input values change. The financial risk analysis shows a range of likely costs for a portfolio, not just one cost. Portfolios that have less risk will have lower cost values for the high end of its cost spectrum relative to another portfolio (e.g. the highest 95th out of 100 runs for a portfolio represents the high end of potential costs for a portfolio). Portfolio J was not included in the financial risk analysis due to high cost at expected values and the time and computing space required to model a portfolio for financial risk.

The ABB PaR model was used to perform Monte Carlo simulation on each portfolio by varying load, gas prices, and market prices stochastically. That is, instead of running a single load or price or a high and low load/price, distributions of loads and prices are developed. The model is run multiple (100) times with different loads and prices from these distributions.

The PaR stochastic analysis results in a distribution of the NPV of the total costs of each portfolio. The expected value and standard deviation of the NPV for each portfolio are determined from the distributions. The 95th percentile of the NPV of cost (5 percent chance that cost is greater than this value) for each portfolio is identified and used to measure and rank the risk of the portfolios.

The stochastic model used in the PaR model is a two-factor mean reverting model. Variable processes assume normality or log-normality as appropriate. Prices are described as having a lognormal distribution. Load growth is modeled as a normal distribution.

Separate volatility, mean-reversion rates and correlation parameters are used for modeling each of the stochastic variables. Mean reversion represents the speed at which a disturbed variable will return to its expected (mean) value.

Volatility, mean-reversion rates and correlation parameters of load, natural gas and electricity prices are estimated by PaR using a regression analysis of five years of historic load, natural gas and electricity price data (2010-2014).

Volatilities are recalibrated to match the standard deviations of the EIRP high, medium and low forecasts for load and gas/market prices. The Electric forecast assumes an 8.45 percent error with a 99 percent confidence interval for all years of the forecast. The errors of the gas and electric market price forecast increase with each year of the forecast. The volatilities of the price forecasts were calibrated to the 2015 error (21 percent for gas and 16 percent for electric market), the average of the errors from 2016 through 2024 (34 percent for gas and 29 percent for electric market) for the years 2016 through 2024, and the average of the errors from 2025 through 2034 (46 percent for gas and 39 percent for electric market) for the years 2025 through 2034 assuming a 95 percent confidence interval on the forecast errors.

Outputs of the 100 draws of load and prices were checked to verify that the distribution of draws were consistent with the distributions described above.

Results

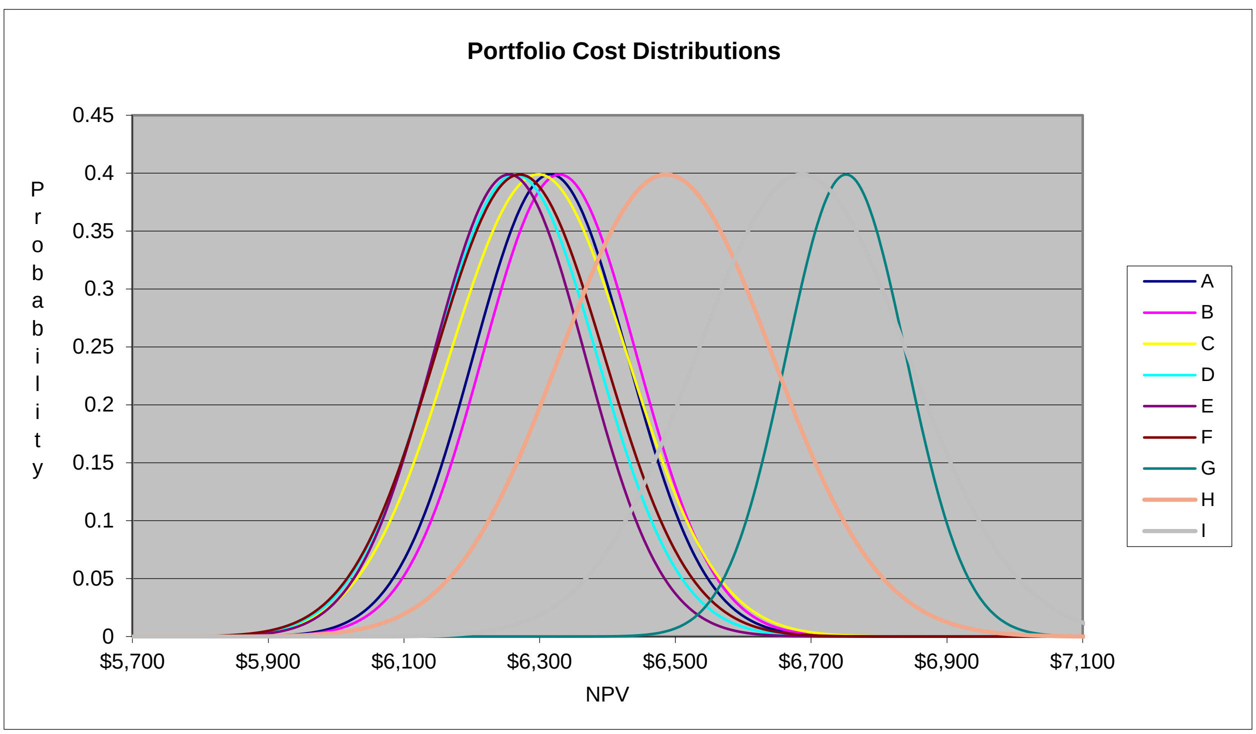
The 95th percentile of the NPV of the net revenue requirement results of that modeling are summarized in Table 9-2 below:

Table 9-2: Financial risk analysis 95th percentile of the NPV of net revenue requirement

EIRP Risk Analysis					
Portfolio	20-yr NPV $Millions	Standard Deviation	95 percentile	EIRP Score	Rank
A	$6,316	$113.79	$6,503	90	4
B	$6,330	$113.86	$6,517	88	6
C	$6,298	$131.20	$6,514	88	5
D	$6,264	$120.39	$6,462	97	2
E	$6,255	$112.37	$6,440	100	1
F	$6,271	$124.88	$6,476	94	3
G	$6,751	$88.51	$6,897	29	8
H	$6,486	$157.27	$6,745	53	7
I	$6,687	$156.47	$6,944	22	9

Figure 9-4 shows the cost distribution of each portfolio's 100 iterations. The 95th percentile value represents a value to the far right of each curve.

Figure 9-4: Portfolio cost distributions for financial risk analysis



9.3 Intangible Decision Matrix

A weighted decision matrix analysis was applied to the portfolios to evaluate factors other than cost. The analysis was performed in conjunction with the advisory group to reach informed consent. In the analysis, the portfolios were ranked relative to one another in six different categories. Each category was assigned a weight to reflect its relative importance. The categories and their relative weights are shown in Table 9-3 below.

Before the EIRP began, the Utilities Board directed staff not to monetize societal costs or benefits, but to include them in the analysis in the non-cost portion of the evaluation. That decision was revisited midway through the process, but the Board upheld their original decision.

In developing the weights of categories in the analysis, for example, Dispatchability and Portfolio Diversity were determined to be the most important categories and assigned a high weighting of nine. Societal Benefits was the second highest weighted, with scores based on CO_2, SO_2, and NO_x emissions as well as the aesthetics of the Drake Power Plant. Customer Resource Preference was ranked as the third most important category which reflects Colorado Springs Utilities' responsibility to its citizen owners. Customer Resource Preference included the customers' desire for more renewable resources, but that renewables should not impact the bill by more than one percent. Development Risk primarily reflects the risk of DSM resources due to uncertainty in DSM potential and long-term commitment to funding. Transmission Reliance considers the risk of using third-party transmission for resources that are unlikely to be developed locally.

Table 9-3: Weighted decision matrix scores and weighting

Criteria	Criteria Weight	Portfolio Scores (higher is better)								
		A	B	C	D	E	F	G	H	I
Dispatchability Maximize ability to call on a resource when needed	9	10	8	10	4	5	8	1	2	1
Portfolio Diversity Maximize smaller units, geographic spacing and different fuels	9	1	1	1	4	0	1	10	4	7
Societal Benefits Maximize city image, minimize negative health and societal impacts	8	1	1	2	2	2	2	3	8	9
Customer Resource Preference Majority of customers prefer certain types of resources	7	2	2	2	6	8	4	6	6	8
Development Risk Maximize ability to permit, meet schedule, secure funding, estimate resource cost, and obtain resource	5	8	6	8	10	4	9	6	9	2
Transmission Reliance Minimize reliance on transmission	1	10	10	10	10	10	10	1	10	6
Total Weighted Score		171	143	179	190	147	180	196	215	216
Normalized Evaluation Scores		48	16	57	70	20	58	77	99	100

9.4 Final Ranking of Portfolios

Summary level scoring is shown in Table 9-4. Each of the scores in sections 9.1 to 9.3 of this report are multiplied by the weight and summed for a total possible score from 0 to 100. Portfolio D was the highest scoring portfolio with Portfolios E and F also faring well. Each metric is described in more detail in later sections. A full evaluation matrix with scores and discrete values can be found in Appendix F.

Table 9-4: Summary portfolio scoring results, higher scores are better

Metric	Weight	Portfolio A Score	Portfolio B Score	Portfolio C Score	Portfolio D Score	Portfolio E Score	Portfolio F Score	Portfolio G Score	Portfolio H Score	Portfolio I Score
Cost without Clean Power Plan	40%	90	88	93	99	100	97	21	63	31
Cost with Clean Power Plan Best Estimate for Springs Utilities Pending State Plan	25%	80	76	89	97	100	94	33	92	58
Financial Risk Uncertainty for Demand, Natural Gas Fuel Prices, and Electric Market Commodity Prices	25%	90	88	88	97	100	94	29	53	22
Intangibles: Dispatchability; Portfolio Diversity; Societal Benefits; Customer Resource Preference; Development Risk; Transmission Reliance	10%	48	16	57	70	20	58	77	99	100
Total Weighted Score		83	78	87	95	92	92	32	71	42
Rank		5	6	4	**1**	2	3	9	7	8

Sensitivities to metric weights were also tested. Feedback during the public process indicated a desire to increase the weight of Cost with CPP and increase the weight of Intangibles. The original weighting for Cost with CPP was lower for that metric due to uncertainty in how the plan will affect Colorado Springs Utilities since a Colorado state plan has yet to be created. As a result, any modeling of the CPP has a high amount of uncertainty and should be used cautiously.

Table 9-5 shows the complete list of sensitives with the first line representing the original scoring. Note Portfolio D scored the highest in every sensitivity and Portfolios E and F are always ranked in the top 4.

Table 9-5: Sensitivity of portfolio scores to metric weights

Metric	Metric Weights*	Portfolio A Score	Portfolio B Score	Portfolio C Score	Portfolio D Score	Portfolio E Score	Portfolio F Score	Portfolio G Score	Portfolio H Score	Portfolio I Score
Total Weighted Score	40% / 25% / 25% / 10%	83	78	87	95	92	92	32	71	42
Rank		5	6	4	**1**	2	3	9	7	8
Total Weighted Score	35% / 25% / 25% / 15%	81	74	85	94	88	90	34	73	46
Rank		5	6	4	**1**	3	2	9	7	8
Total Weighted Score	25% / 25% / 25% / 25%	77	67	82	91	80	86	40	77	53
Rank		5	7	3	**1**	4	2	9	6	8
Total Weighted Score	25% / 40% / 25% / 10%	82	76	87	95	92	91	33	76	46
Rank		5	6	4	**1**	2	3	9	7	8
Total Weighted Score	0% / 65% / 25% / 10%	79	73	86	94	92	90	36	83	53
Rank		6	7	4	1	2	3	9	5	8

10.0 Recommendations and Action Plans

Based on all factors including cost (with and without the EPA's CPP), financial risk and intangibles, Portfolio D scored the highest. This portfolio calls for:

- Running Drake Unit 5 on natural gas and using it primarily as a peaking unit beginning in 2018.
- Ten percent demand reduction through DSM goal with spending capped at two percent of the customer's bill by 2020.
- Twenty percent renewable energy goal with incremental spending capped at one percent of the customer's bill. Based on today's cost estimates this would be 80 megawatts of new solar power, by 2020.

At their final public meeting, the CAG reached a consensus to support Portfolio D with additional options to mothball the Unit for up to three years starting in 2015 or 2016 (with the potential to restart it within the three years as a natural gas unit); or decommission the Unit no later than December 2017. Pros and cons for each of the three options were presented to the Utilities Board and are shown in Table 10-1.

Table 10-1: Pros and cons for three options related to the future of Drake 5

Decommission Option - Pros • Results in $2 million in savings for 10-year Net Present Value • Avoids additional $1 million investment for burner upgrades • Avoids an estimated $400,000 annually for labor and maintenance costs • Will help show attainment with air quality standards for sulfur dioxide, ozone, and visibility • Allow for staff transition from Drake 5 to scrubbers	**Decommission Option - Cons** • Risks spending more to replace capacity if it is needed • Requires waste management and cleanup costs of approximately $100,000 to $200,000 • Small risk of lost credit under CPP
Natural Gas Option - Pros • Keeps 46 MW of dispatchable capacity available as demand forecast shows capacity is needed in 10-15 years • Results in $30 million savings for 20-year Net Present Value • Provides backup capacity in case of high economic development • Provides emergency outage support in case another unit is out of service	**Natural Gas Option - Cons** • Requires additional $1 million investment for existing burner retrofit by Dec 2017 • Requires an estimated $400,000 for annual labor and maintenance costs • Model results show it generates for only 650 hours per year operation (2018-2030 average) • Presents age risks since current unit has been operating for 53 years and would reach 68 years in 2030 when less than 5 percent of coal units this old in the U.S. would be operating
Mothball Option - Pros • Delays additional $1 million investment to retrofit burners for natural gas operation • Provides time to see how demand forecast develops and better determine whether or not to invest in the capacity • Allows unit to stay mothballed for up to 3 years starting in 2015-2016 • Allows restart unit within 3 years and perhaps convert it to natural gas operation by 2018 if needed, or retire	**Mothball Option - Cons** • Costs $4.6-$6.2 million estimate to mothball and restart after three years • Could result in additional expenses to bring the unit back online if keeping the unit mothballed for more than 3 years

10.1 Approved Portfolio

At the November 2015 Utilities Board meeting, the Board approved Portfolio D with modifications to decommission all three units at the Drake Power Plant no later than Dec. 31, 2035; and to increase the DSM goal to 12 percent by 2020 while keeping the spending cap at two percent. In January 2016, the Board decided to decommission Drake Unit 5 on or before Dec. 31, 2017.

New resource acquisitions for 2015-2024 are described below. Figure 10-1 shows the full expansion plan for 2015 through 2035 assuming the CPP starts in 2022 while Figure 10-2 shows what the expansion plan would be without the CPP (first five years are identical). A comparison of the two plans will illustrate the resource changes that would be a direct result of the CPP.

Modified Portfolio D Resources 2015-2024

By 2017	Decommissioning of Drake 5
2019	Solar – 40 MW
2020	Solar – 40 MW
2023	Potential Decommissioning of Drake 6 pending new NOx requirement and CPP

Figure 10-1: Modified Portfolio D expansion plan 2015-2034 assuming CPP in 2022

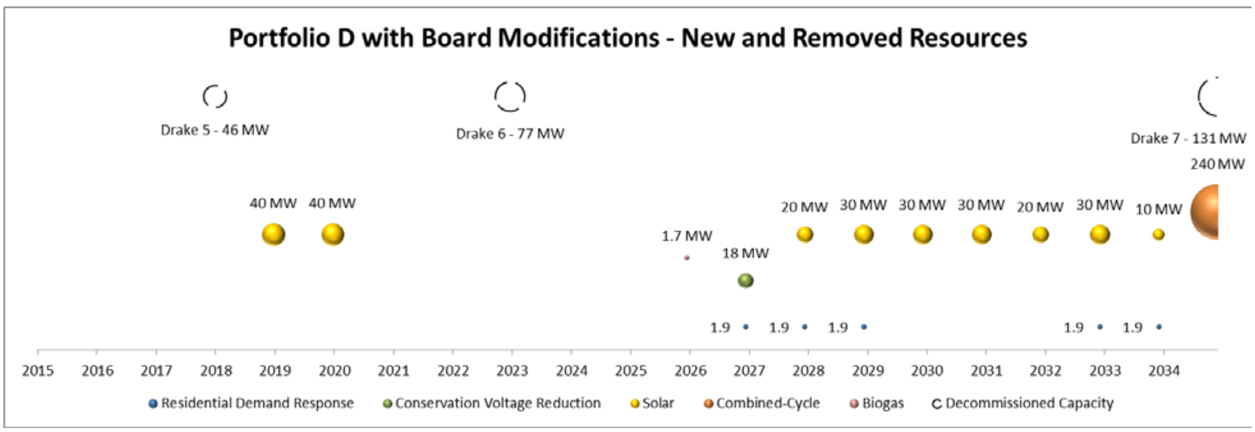
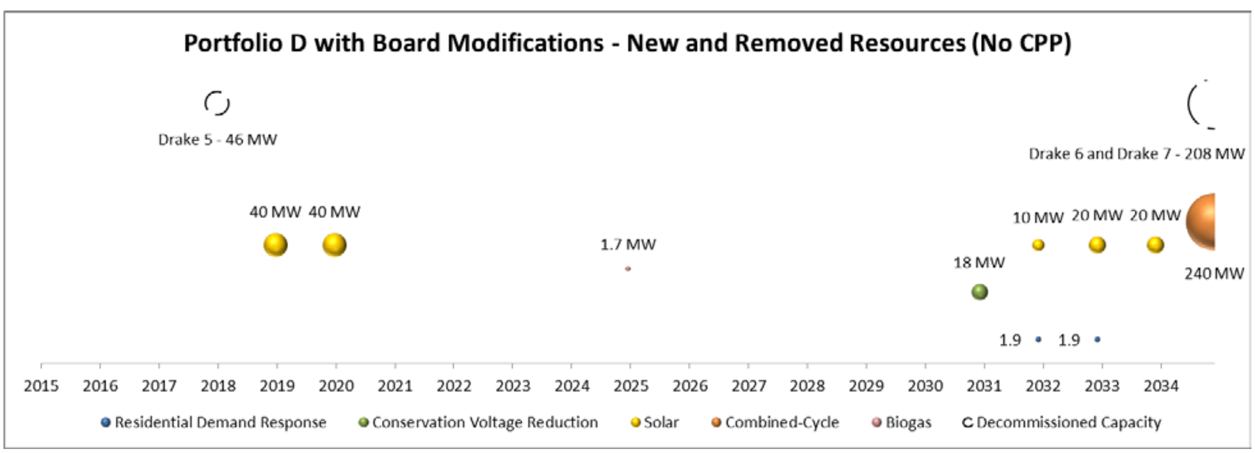


Figure 10-2: Modified Portfolio D expansion Plan 2015-2034 with no CPP



Comparing the two expansion plans, the CPP could change the resource plan by decommissioning the coal-fired Drake 6 unit earlier and adding additional solar capacity starting in 2028.

The addition of 40 MW of new solar PV in both 2019 and 2020 is based on today's cost estimates for what could be achieved within the one percent incremental spending cap and could change at the time of procurement if more or less capacity is achievable within that cap.

Solar is in the plan primarily to meet the renewable energy goals in the UPAC Energy Vision as part of the approved portfolio. With the expiration of the federal wind Production Tax Credit, solar is a cost-competitive resource that can also contribute some reliable capacity during times of peak demand. Actual acquisition of renewable resources to meet the UPAC Energy Vision, whether it is solar or wind, will depend on the bids received at the time of procurement. Resources will be selected to maximize the amount of funding available to get as much renewable energy as possible within the one percent incremental spending cap.

10.2 The Action Plan

The Action Plan identifies the steps to be taken to meet future demand and potential emerging industry and regulatory needs. Of note in the approved portfolio is the large amount of solar acquisition and the Drake unit decommissioning. As a result, much of the action plan is designed to evaluate the impact of not only utility scale solar, but the impact of increasing customer-owned generation in the Colorado Springs Utilities Service Territory. System impacts of decommissioning and more in-depth reviews of new capacity to replace Drake capacity will also be a large part of the action plan. Key steps include:

- Add planning for Drake Plant decommissioning no later than 2035 to the Utilities Board Strategic Planning Committee agenda.
- Continue to plan in a cost-effective manner that allows us to maintain a regional cost advantage for Colorado Springs Utilities.
- Decommission Drake 5 on or before December 31, 2017.
    - Stop SO2 and NOx control projects for Drake 5.
    - Develop plan for Drake 5 decommissioning.
- Develop long-term O&M spending, capital spending, and staffing strategies for Portfolio D generating units.
- Complete a solar integration study to investigate the impact of adding up to 80 MW additional solar capacity by 2020.
- Complete a solar rollout plan to determine how best to increase solar capacity, be it rooftop solar, community solar, or utility scale solar.
- Evaluate transmission requirements and timing, especially as it relates to the decommissioning of the Drake plant units.
- Consider results of the DSM Potential Study and determine if any modifications to the portfolio would be needed.
- Investigate new rate structures and options:
    - Bill rider to support the UPAC Energy Vision
    - Net energy metering alternatives
    - Grid service support charges
- Continue the examination of potential new renewable resources and efficiency upgrades at existing power plants.
- Explore opportunities for marketing surplus generation.

The Action Plan will serve as Colorado Springs Utilities' guide for resource planning in the coming years.

11.0 Addendum 1 – Developments During and After Completion of EIRP

This addendum provides a summary of the events following the EIRP analysis but before the submission of the report to Western.

During the EIRP, the Utilities Board approved the acquisition of 10 MW of solar power through power purchase agreement sited at Colorado Springs Utilities' Clear Spring Ranch site. This acquisition enabled Colorado Springs Utilities to take advantage of the expiring solar 3 times renewable energy credit multiplier for CO RES compliance. Originally scheduled to expire on June 30, 2015, the state legislature passed an extension for the multiplier allowing units that are producing electricity prior to Dec. 31, 2016 to qualify as long as the project was under contract prior to Aug. 1, 2015. Action prior to the completion of the EIRP was necessary to meet this contract deadline. Colorado Springs Utilities was able to meet the contract deadline and the project is scheduled to be online by the end of 2016. This project will be the first 10 MW of the planned solar expansion as part of the Modified Portfolio D.

In the summer of 2015, 2.5 MW of community solar garden projects were completed and several SREC acquisitions were completed to help meet the CO RES and achieve the UPAC Energy Vision.

In addition to the new resource acquisitions, natural gas prices significantly decreased and are forecasted to be lower than originally forecasted in the EIRP. Lower natural gas prices reduce the cost of providing energy from traditional resources which increases the incremental cost of renewable energy. As a result, the amount of renewable energy acquired within the one percent bill impact cap could be lower than the 80 MW of solar that was originally forecasted. Colorado Springs Utilities will always review the bill impact of each new renewable resource before acquisition using updated incremental cost forecasts.

The action plan stated Colorado Springs Utilities would decommission Drake 5 on or before Dec. 31, 2017. A decommissioning plan was developed and Drake 5 will not operate past Dec. 31, 2016 and will be in inactive reserve status until the physical separation of the unit is complete in early 2017.

Other major developments since the completion of the EIRP are the extension of the federal Investment Tax Credit (ITC) for solar, extension of the federal PTC for wind, and a stay on the EPA's CPP.

The wind PTC extension could increase the possibility of acquiring some wind in addition to solar to meet the UPAC Energy Vision. Colorado Springs Utilities will issue requests for proposals to acquire new renewable resources and consider any resource that can provide the most renewable energy within the one percent bill impact cap.

Colorado is continuing to develop a state plan for the CPP during the stay. There is a significant amount of uncertainty related to the future of the CPP. Colorado Springs Utilities will continue to monitor all developments and evaluate their impact on the approved resource plan.

Colorado Springs Utilities is also participating in discussions with the Mountain West Transmission Group (MWTG). The MWTG's goal is to explore the development of a joint transmission tariff. It is intended that, by operating under a joint transmission tariff, each participant's customers and stakeholders will benefit as a result of improved efficiency of the existing and future energy systems. The potential impact of Colorado Springs Utilities operating under a joint transmission tariff is being studied and could become part of the analysis in future EIRPs.

Appendix A – Current DSM Measures

RESIDENTIAL REBATES

Whether you're buying a new home, remodeling or just trying to reduce your monthly utility bill, we are here to help with money-saving rebates on energy efficient products. Plus we have free tools at csu.org that can help you measure and track your utility use.

Our Energy Depot Audit tool allows you to input information about your home and appliances and evaluates what measures you can take to make your home more energy efficient. And our My Usage tool tracks your electricity, natural gas and water usage. By knowing how much you are using, you can make decisions on ways to reduce your consumption and your bill.

Energy efficient appliances

When replacing your appliances, look for energy-efficient models that have earned the ENERGY STAR® label. ENERGY STAR certified appliances help consumers save money on operating costs by reducing energy use without sacrificing perfomance.

Rebate amounts:

- Electric dryer: $50
- Natural gas boiler: $250
- Natural gas furnace: $250
- Natural gas water heater: $50

Windows

Your home's windows play a large part in regulating energy use and costs. Ask for ENERGY STAR qualified high-efficiency windows with the ENERGY STAR climate zone label and verify the products qualify in Colorado.

Rebate amounts:

- Single family residence windows: $4.67 per square feet, up to $200
- Small multi-family residence (three stories or less) windows: $4.67 per square feet, up to $12,000

Air sealing and insulation

Air leaks waste a lot of energy and increase your utility costs. A well-sealed home and duct work, coupled with the right amount of insultion, can make a real difference. To qualify for the duct sealing and insulation rebates, work must be performed by a licensed Colorado contractor.

Rebate amounts:

- Duct sealing: 40 percent of job cost, up to $100
- Insulation and air sealing: 40 percent of job cost, up to $200

PRIOR TO ANY PURCHASE, VISIT CSU.ORG

for information on the rules and effective dates for individual rebates.

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Renewable energy

Renewable energy helps protect the environment, diversifies our energy supply, creates energy independence and reduces our summer peak capacity requirements.

- Photovoltaics, or solar electric panels, convert the energy of the sun into useful electricity. The rebate rate is $0.25 per AC watt. Arrays cannot exceed 120 percent of the customer's use.
- Solar thermal water heating systems collect the sun's energy in the form of thermal or heat energy to heat water for your home. Rebates available up to $3,000.
- Wind power is available for purchase in 100-kilowatt hour blocks for an additional $2.21 per block for residential customers.

In-store discounts

We have partnered with local retailers to bring you immediate discounts on ENERGY STAR certified LED light bulbs and WaterSense® showerheads. To see a full list of participating retailers, visit csu.org.

- ENERGY STAR LEDs use up to 90 percent less energy and last up to 25 times longer than an incandescent bulbs.
- You could save 13,000-plus gallons and $214 in water and energy costs per year by installing WaterSense labeled showerheads. You can also exchange your old showerheads for WaterSense models at our Conservation and Environmental Center.

Irrigation equipment

Landscape watering makes up nearly half of all residential water use in Colorado Springs. Used properly, efficient irrigation equipment can reduce landscape water use from 5 to 20 percent or more.

Customers must purchase and install qualifying irrigation equipment. Rebate amounts:

- WaterSense® certified smart irrigation controller: half of the purchase price, up to $200
- Wired rain sensor shut-off device: up to $25
- Wireless rain sensor shut-off device: up to $50

Models of the following devices must be from our list of qualifying equipment. Rebate amounts:

- Conversion of overhead to drip irrigation: up to $200
- Sprinkler heads with check valves: $5 each, minimum of 5, limit of 80
- Rotating matched precipitation spray nozzle: up to $4 each, minimum of 5, limit of 80

Your one stop for all things energy and water efficiency.

CONSERVATION & ENVIRONMENTAL CENTER

Learn how to use energy and water wisely by touring our Xeriscape Demonstration Garden, using our extensive resource library or trying out one of our hands-on displays, including solar power, LED lighting, low-flow indoor and outdoor water equipment, holiday lights and more.

Open Monday through Friday, 8 a.m. to 5 p.m.

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BUSINESS REBATES

Whether you're remodeling or simply trying to reduce your monthly utilities bill, we can help with money-saving business rebates on energy- and water-efficient products. Before starting a project, it's best to know where to start.

No matter the size of your business, we offer a FREE basic or advanced energy audit that can help your bottom line. You can also track your electricity, natural gas and water daily use at csu.org with My Usage to make informed decisions on ways to reduce your consumption and your bill.

Lighting

You can save more than 25 percent on your lighting energy costs by installing energy efficient lighting.

Rebate amounts:

- Lighting: Up to 50 percent of your project cost. Amount varies based on the energy saved as determined by pre- and post-inspections of the project.
- Occupancy sensor rebate for interior lighting: $24.70 for each light switch control point replaced with a minimum control of 150 watts, including the ballast.

Custom electric

Looking for an incentive that's tailored to your unique or industry energy demands? We will work with medium to large commercial customers to determine equipment eligibility, measurement, potential rebate amounts and verification of specialized projects. Contact us for pre-approval and a rebate estimate for your project. Once work is complete, the verified demand and energy savings will be use to determine the final rebate amount.

Windows

Windows play a large part in regulating energy use and costs. Ask for qualified high-efficiency windows that are rated by the National Fenestration Rating Council.

Rebate amounts:

- Large multi-family building (four stories or higher) windows: $1.40 per square feet, up to $12,000
- Business property windows: $1.40 per square feet, up to $17,500

WaterSense® showerheads

Reduce water use and the amount of energy used to heat the water with WaterSense showerheads.

Rebate amount:

- Install or retrofit 10 or more showerheads: $10 or 50 percent (whichever is less) on each one installed

Builder Incentive Program

ENERGY STAR® homes are verified to save at least 15 percent more energy than local code requires. This program partially offsets the cost (up to $800 per qualified home) that builders incur to qualify homes under the Energy Star Certified New Homes program.

PRIOR TO ANY PURCHASE, VISIT CSU.ORG

for information on the rules and effective dates for individual rebates.

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Renewable energy

Renewable energy helps protect the environment, diversifies our energy supply, creates energy independence and reduces our summer peak capacity requirements.

- Photovoltaics, or solar electric panels, convert the energy of the sun into useful electricity. The rebate rate is $0.25 per AC watt with a 100 kW limit.
- Solar thermal water heating systems collect the sun's energy in the form of thermal or heat energy for use in space heating and water heating. Rebates available up to $15,000.
- Wind power is available for purchase in 100-kilowatt hour blocks for an additional $2.31 per block.

Heating, ventilation and air conditioning

Upgrade these systems for year-round comfort for your employees and customers and see dramatic energy savings with improved designs and controls.

- High-efficiency air conditioner: Replace a package AC unit or split system AC equipment with high-efficiency AC equipment to receive a rebate (minimum five tons – smaller units can be combined, maximum 25 tons). The rebate amount varies based on how much the new unit exceeds International Energy Conservation Codes (IECC) 2009 minimum efficiencies.
- Evaporative cooling systems: Replace air-cooled AC with direct evaporative cooling (swamp cooling) to receive a rebate of $162.50 per ton of air conditioning (minimum five tons).
- Package terminal air conditioners (PTAC): Replace PTAC units with high-efficiency PTAC units to receive a rebate of $5.90/ton per 0.1 Energy Efficiency Rating (EER) over code for each PTAC replacement (minimum of 0.5 tons cooling capacity per unit).

Motors, belts and pulleys

Get a quick return on your investment with these cost-effective measures.

- Receive $60 for each shaded pole (minimum 25 watts) or permanent split capacitor motor (minimum 1/50th HP) when you retrofit electronically commutated motors (walk-in/reach-in cooler/freezer, HVAC fan powered VAV box, fan coil, furnace).
- Replace standard belts with synchronous belts and pulleys to receive a rebate of $9.50 for each replacement (requires changing both belt and sprockets) multiplied times the horsepower rating of each motor, with a minimum of a 5HP motor replacement.

COMMERCIAL & INDUSTRIAL ENERGY AUDITS

Visit csu.org to learn about our energy audits that can identify ways to help lower your utility costs.

A basic audit is suitable for smaller facilities and ideal for business owners who want to learn about energy-saving options and get an idea of how their use compares with similar facilities.

An advanced audit is a more comprehensive product suitable for larger or complex facilities. These take more time and provide a wider range of analysis and opportunities including a review of operations and maintenance.

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Appendix B – Complete EIRP Customer Survey Results

EIRP Residential and Business Research Summary

Presented to Customer Advisory Group (CAG)

February 4, 2015

Purpose

- To determine customer willingness to pay an additional amount to purchase renewable energy from Colorado Springs Utilities
- To determine customer opinion of how Colorado Springs Utilities should invest in electricity sources
- To support the EIRP process and Energy Vision

Survey Methodology

- 635 randomly selected residential customers were surveyed by phone in November 2014
  - +/- 3.88 confidence interval
- 270 randomly selected business customers were surveyed by phone in November and December 2014
  - +/- 5.93 confidence interval
- Survey was conducted at same time of year to better enable trending

Key Takeaways

- Increased price sensitivity overall
  - Higher income less sensitive to price
- Majority support in residential and business customer bases for the addition of renewable sources
- Majority support for a bill amount increase of up to 2%
- The relative importance of investment in natural gas and coal increased from 2013

Customer Prioritization of New Electricity Sources

- When considering new electricity sources, low price increased significantly and was selected as the first priority by over half of residential and business customers.
- Adequate supply was chosen as the second priority and low environmental emissions was the third priority, consistent with 2013 survey results.

Customer Importance of "Investments"

- How important should each of the following be to Colorado Springs Utilities?
  - Investment in programs and products that help customers use less electricity
  - Investment in renewable energy sources such as wind, solar or hydro power
  - Investment in electric energy produced by coal
  - Investment in electric energy produced by natural gas
  - Keeping electricity rates as low as possible regardless of the energy source

Customer Importance of "Investments"

Residential

- Price was the greatest priority, followed closely by…
- Demand side management and renewable sources which measured about the same.
- Investments in natural gas and coal received lower priority.

Business

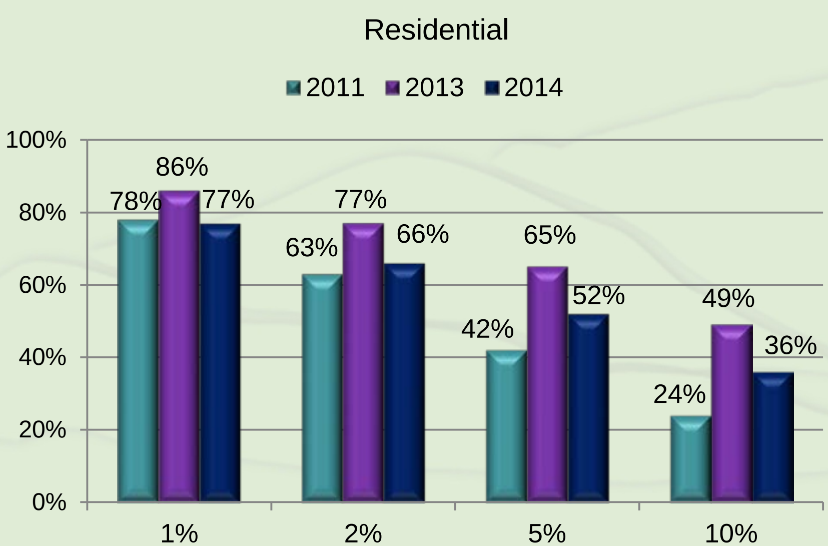
- Price was the greatest priority.
- Demand side management was favored over investments in renewable sources, natural gas, and coal.
- The importance of investments in renewables and natural gas were relatively the same, with coal the lowest priority.

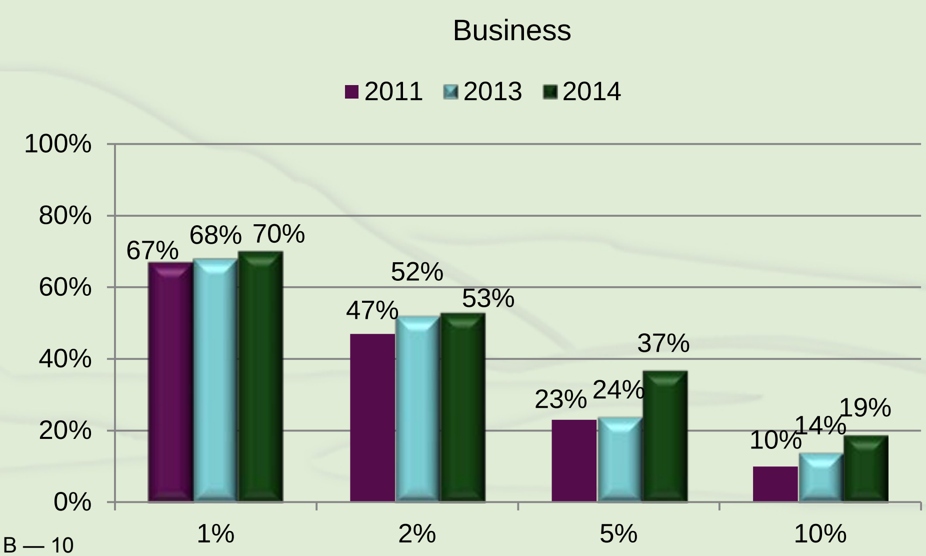
Residential Customer Importance of "Investments" by Income

- Customers reporting an income <$45,000 per year rated price, renewable sources, and demand side management most favorably.
- Customers reporting an income >$45,000 per year rated renewable sources, demand side management, and price most favorably.
- Customers with higher income are less price-sensitive.

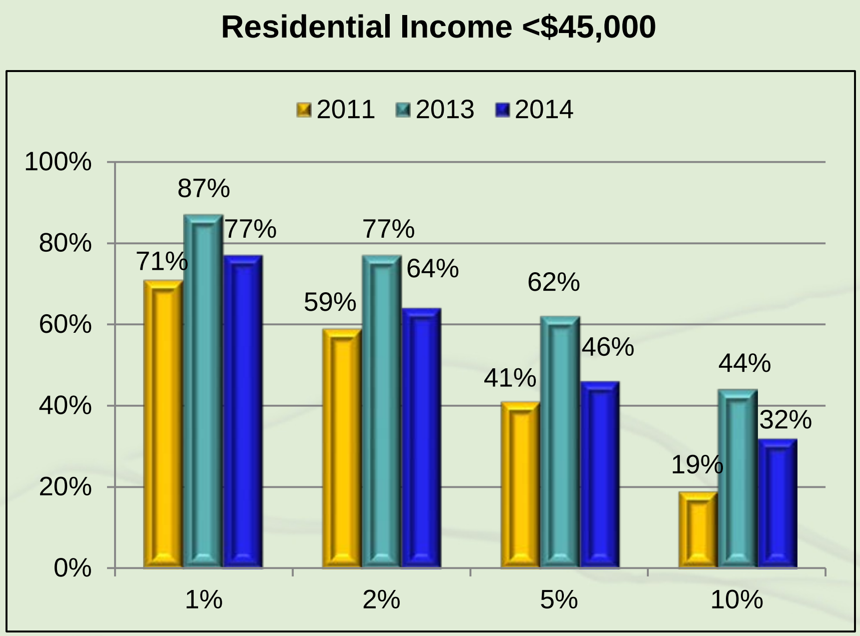
Customer Willingness to Pay for Renewables

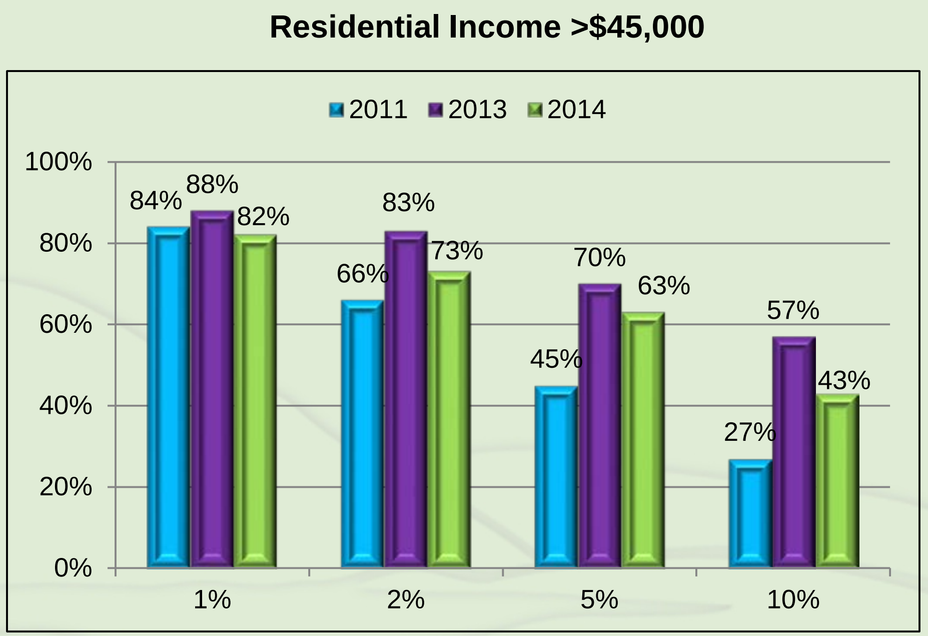
The majority of both residential and business customers indicated willingness to pay more per month for electricity to cover any increased cost to provide renewable energy.





Income Influences Residential Customer Willingness to Pay for Renewables





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Supply Portfolio Customer Opinion Trending

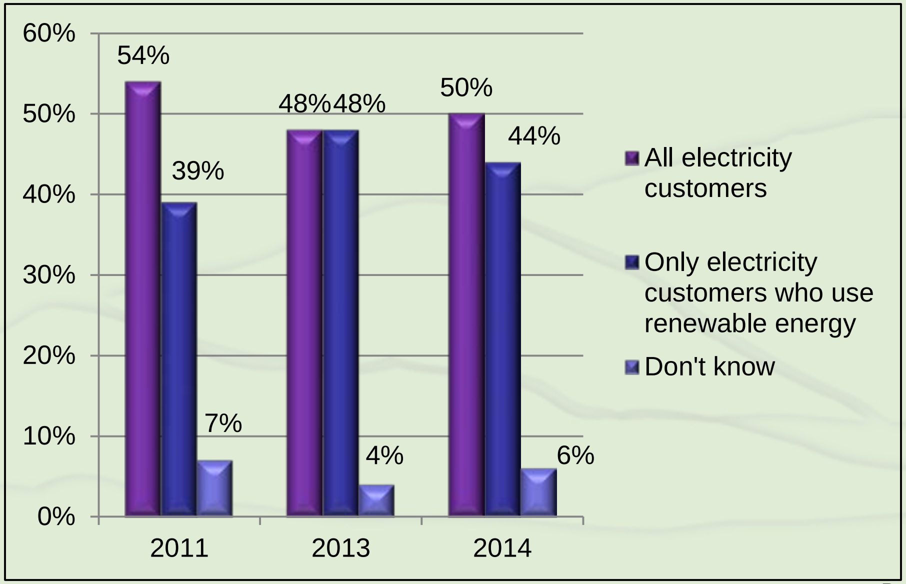
The majority of customers think Colorado Springs Utilities should include renewable resources in our portfolio even if they could cost more than other options.

	2011	2013	2014	Change (2013 to 2014)
Residential	62%	77%	65%	▼12%
Business	65%	77%	65%	▼12%

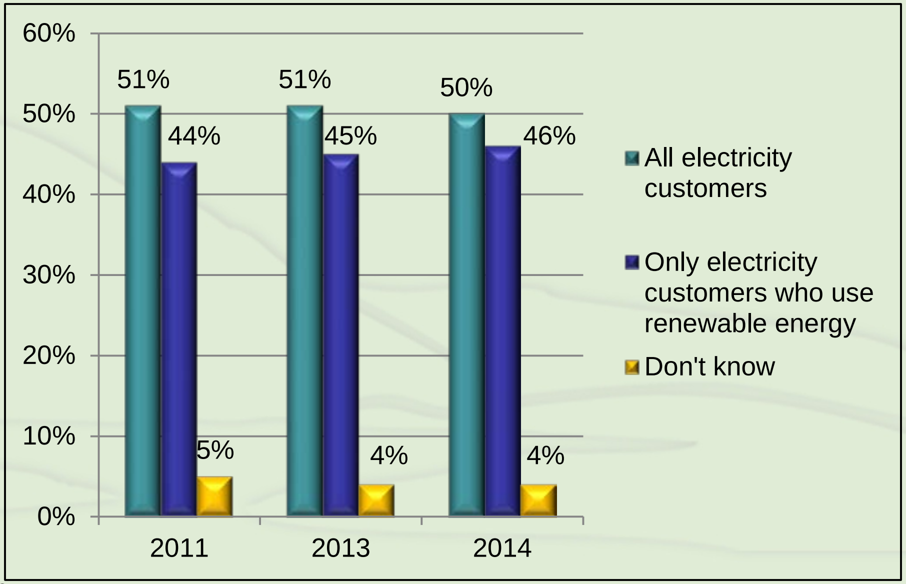
Who Should Pay For Renewable Energy?

While residential opinions changed slightly, business opinion remained stable.

Residential

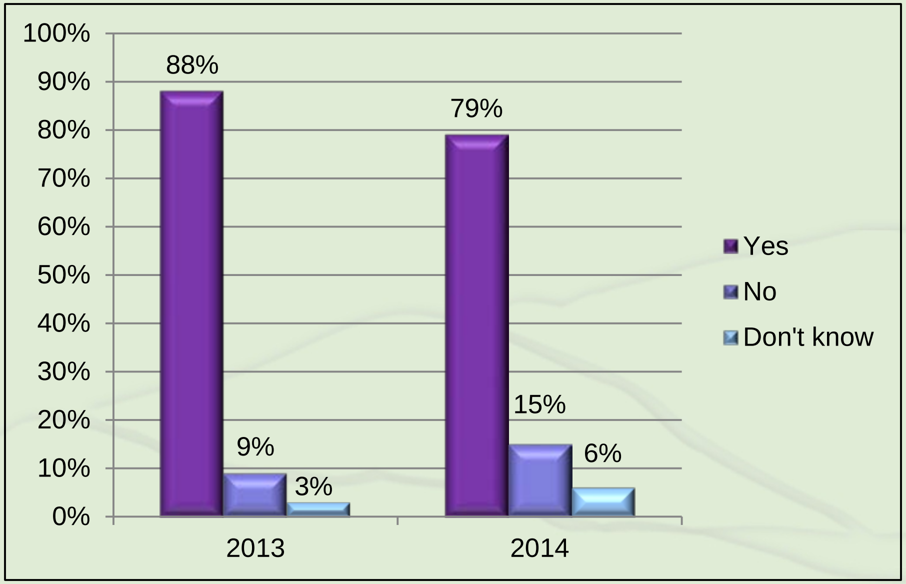


Business

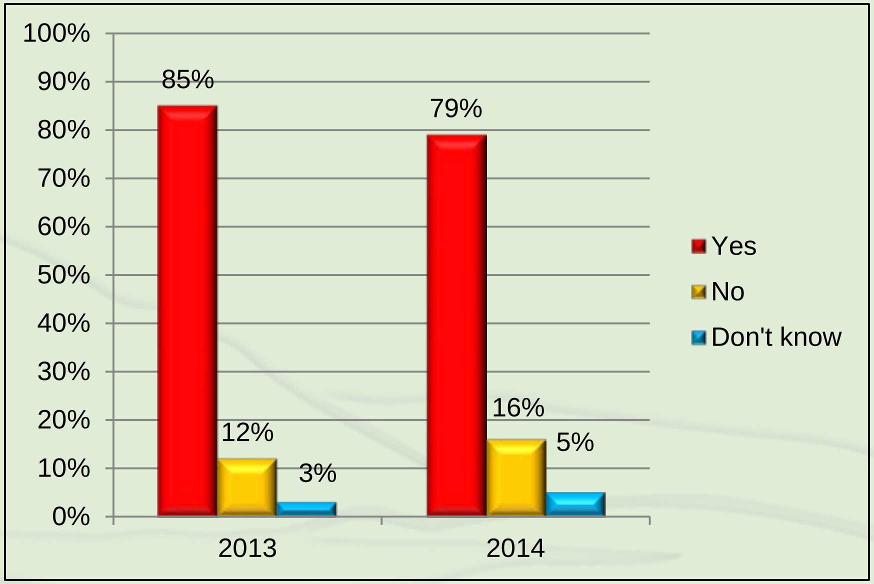


"Do you think Colorado Springs Utilities should offer renewable energy programs to customers who would like increased renewables where they would subscribe each month to support the increased use of renewables?"

Residential



Business



Question not asked on 2011 survey; in 2014 the question wording changed from "option" to "subscription."

Possible Questions/Topics for the Spring Survey

- Is carbon reduction a necessity?
- Generation versus purchase
- Renewable price stability versus fluctuation in fossil fuels because of market variation
- How likely do you think it is renewable sources could actually cost less at some time in the future?

Possible Questions/Topics for the Spring Survey

- Are you aware that by changing nothing about our existing generation mix, we will meet all federal and state requirements?
- If we were to increase the amount of renewable source in our portfolio, what do you think it will do to cost?
- If you had to express your opinion as to whether Colorado Springs Utilities should close the downtown Drake plant, what would it be?

Possible Questions/Topics for the Spring Survey

- Did you notice any changes to your electric bill amount due to the Drake Plant fire in 2014? If yes, what did you notice?
- Are you aware of the term "carbon footprint?" If yes, do you have the desire to reduce yours?
- Do you believe you could reduce your electricity usage in your home? If yes, what might you do to make that happen?

Spring 2015 Survey
Residential & Business Customers

Colorado Springs Utilities
It's how we're all connected

Prepared for EIRP

May 2015

Purpose

Colorado Springs Utilities
It's how we're all connected

- To address specific questions raised by CAG and EIRP team through planning sessions
- To determine customer opinion
- To support EIRP planning process

Survey Methodology

- 350 randomly selected residential customers were surveyed by phone in March 2015
- +/- 5.23 confidence interval

  141 business customers surveyed electronically who were subscribers to electronic newsletter.

  +/-8.20 confidence interval

You will note the percents on some of the questions may not total to 100%. This is because many questions allowed more than one response or did not require a response to proceed.

What would Renewables do to Price?

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Question:

If we were to increase the amount of renewable sources (wind, solar or hydro) in our energy supply portfolio, what do you think it would do to the price you pay for electricity? Would it decrease the price, increase the price, or would it have no impact on the price? *(Choices were rotated)*

Residential Results

- Decrease 29.7%
- No Impact 11.1%
- Increase 49.4%
- Don't know/Refused *(Not read)* 9.7%

Business Results

- Decrease 31.0%
- No Impact 16.0%
- Increase 55.0%

Wind farms?

Question:
Are you aware of any wind farms near Colorado Springs?

Residential Results

• Yes	36.3%
• No	61.4%
• Don't know *(Not read)*	2.3%
• Refused *(Not read)*	0.0%

Business Results

• Yes	46.0%
• No	43.0%
• Don't know *(Not read)*	11.0%
• Refused *(Not read)*	0.0%

Can you subscribe to wind power?

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Question:
Are you aware of an option, provided by Colorado Springs Utilities, for a residential customer to subscribe to the use of wind produced energy?

Residential Results		Business Results	
• Yes	18.3%	• Yes	39.0%
• No	81.1%	• No	50.0%
• Don't know *(Not read)*	0.6%	• Don't know *(Not read)*	12.0%

(In 2013 survey: "To your knowledge, does CSU presently offer a renewable energy program?
(28.3% said "yes")

Should CSU include renewable energy?

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Question:
Electric rates are subject to change given such things as fluctuations in costs to generate electricity. In addition to those changes to electric rates, do you think Colorado Springs Utilities should include renewable energy sources such as wind, solar and hydro even if they could cost more than other supply options?

Residential Results		**Business Results**	
• Yes	63.1%	• Yes	62.0%
• No	30.9%	• No	24.0%
• Don't know *(Not read)*	6.0%	• Don't know *(Not read)*	15.0%

(The response to the similar question in 2014 RES study was 65.4% "yes". The information regarding "in addition" cost did not significantly change response)

Should CSU increase renewable investment?

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Question:
CSU currently gets about 10% of its energy mix from renewable sources (mostly hydro and small amounts of wind and solar). Therefore, CSU already meets the Colorado Renewable Energy Standard requirements for municipal utilities through the year 2023 with no new investments in renewable energy. Do you think CSU should increase from 10% to 20% renewable sources by 2020 if doing so could cause increases in electric rates in the future?

Residential Results

- Yes 51.4%
- No 41.4%
- Don't know *(Not read)* 7.1%

Business Results

- Yes 51.0%
- No 49.0%
- Don't know *(Not read)* 15.0%

(The response to the same question in 2013 RES study was 54.7% "yes". Many business customers provided a yes or not and said don't know.)

Which renewable should CSU prioritize?

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Question:
Which renewable should Colorado Springs Utilities prioritize in our planning efforts?

	Residential	Business
• Solar	46.0%	49.0%
• Wind	33.0%	31.0%

- Percent represents those who listed each as First Priority
- Hydro was clearly considered a 3rd Priority

Why should CSU prioritize a particular renewable?

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When residential customers explained the rationale for the priority expressed, common responses followed:

• All of the sun/ A lot of sun days/ 300 days of sun	38.8%
• We have lots of windy places (out east)/ Windy Days	21.4%
• Less expensive/ Cost effective/ Cheaper	16.8%
• Better option/ Reliable	16.8%
• Abundant/ Plenty of it	12.8%
• Environmentally safe	9.8%
• Hydro/ Water/ Rivers	6.1%
• Expensive	2.8%
• Already use it, increase it	2.4%
• Dangerous to animals/ Windmills	1.8%

Why should CSU prioritize a particilar renewable?

- When business customers explained the rationale for the priority expressed, common responses followed:

- Costs for installed solar continue to decline
- Resources are available on sustainable basis

Would you choose to use "Time of Use" rates if it were an option?

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Question:
Time of use rates are based on the time of day in which you use electricity. Similar to peak pricing used for air travel, cell phone, hotel stays, etc., time of use electric rates mean that you pay lower rates during periods of low demand (i.e. during the night) and higher rates during periods of maximum demand (i.e. during the dinner hour). On a 1 to 10 scale, where 1 means you're "extremely unlikely" and 10 means you're "extremely likely"; if you could choose "time of use rates" for your home, how likely would you be to do so?

Residential Results

- Very likely to choose "Time of Use" rates-top box 34.6%
- Very unlikely to choose "Time of Use" rates-bottom 26.8%

Business Results

- Very likely to choose "Time of Use" rates-top box 30.0%
- Very unlikely to choose "Time of Use" rates-bottom 17.0%

How likely are you to purchase an electric vehicle in the next 10 years?

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Question:
Electric vehicles are becoming increasingly available. How likely will you be to purchase an electric vehicle in the next ten years? Please use a scale from 1 to 10 where 1 means you're "extremely unlikely" and 10 means you're "extremely likely".

Residential Results

- Very likely to purchase an electric vehicle-top box 14.5%
- Very unlikely to purchase an electric vehicle-bottom 62.3%

Business Results

- Very likely to purchase an electric vehicle-top box 18.0%
- Very unlikely to purchase an electric vehicle-bottom 45.0%

How likely are you to install solar electric panels in the next 10 years?

Question:
Solar electric panels convert the renewable energy of the sun into useful electricity that is pollution-free and avoids burning fossil fuels. Every customer has the opportunity to install solar electric panels on their home or business. By installing solar electric panels, your electric bill could be reduced. Using the same scale, where 1 means you're "extremely unlikely" and 10 means you're "extremely likely", how likely will you be to install solar electric panels on your home or business in the next 10 years?

Residential Results

- Very likely to install solar electric panels-top box 24.9%
- Very unlikely to install solar electric panels-bottom 39.1%

Business Results

- Very likely to install solar electric panels –top box 21.0%
- Very unlikely to install solar electric panels -bottom 25.0%

How likely are you to sign up for wind power in the next year?

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Question:
Wind power is available for purchase in 100-kilowatt hour blocks for $2.14 per block for residential customers. Purchasing one block of wind power for 12 months is equivalent to saving:

- 1 ton of carbon dioxide a year, or
- the emissions of driving 1,200 miles a year in an SUV

- Residential
- Very likely to sign up for wind power this year-top box 18.0%
- Very unlikely to sign up for wind power this year -bottom 42.1%

- Business
- Very likely to sign up for wind power this year-top box 18%
- Very unlikely to sign up for windpower this year-bottom 31%

What programs do customers support?

The programs/products most likely to be selected by the customer in order of most to least likely:

- Time of Use rates – (no timeframe referenced)
- Solar electric panels in next ten years
- Purchase of wind in next year
- Purchase of an electric vehicle in next ten years

Which is more environmentally sustainable?

Question:

Which of the following do you believe would be most environmentally sustainable for Colorado Springs? *(Statements were rotated)*

Residential Results

- Using renewable sources such as wind or solar to produce electricity 69.1%
- Using coal & natural gas to produce electricity 27.1%
- Don't know *(Not read)* 3.4%
- Refused *(Not read)* 0.3%

Business Results

- Using renewable sources such as wind or solar to produce electricity 65.0%
- Using coal & natural gas to produce electricity 23.0%
- Don't know *(Not read)* 13.0%

What does the future of the Drake Power Plant look like?

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Question:
There has been much community discussion about the possible decommissioning of the Drake Power Plant downtown. Do you support its closure or maintaining the Drake Power Plant as is? *(Statements were rotated)*

Residential Results

- Closure 18.0%
- Maintain as is 58.9%
- Don't know *(Not read)* 20.6%
- Refused *(Not read)* 2.6 %

Business Results

- Closure 22.0%
- Maintain as is 44.0%
- Don't know *(Not read)* 35.0%

If the Drake Power Plant were closed, how will it affect…?

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Of the following conditions that could improve if the Drake Power Plant were closed(Residential customer opinion):

- Air quality of Colorado Springs was expected to be most favorably impacted(30% top box)
- The vitality of downtown was expected to be the 2nd most favorably impacted with 18% top box, but many did not know(17% did not know)
- 44% of residential customers felt the electric rate would worsen(bottom box)-only 12% felt it would improve
- 36% of residential customers felt the jobless rate in Colorado Springs would worsen(bottom box)-only 10% felt it would improve

If the Drake Power Plant were closed, how will it affect…?

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Of the following conditions that could improve if the Drake Power Plant were closed(Business customer opinion):

- Air quality of Colorado Springs was expected to be most favorably impacted(41% top box)
- The vitality of downtown was expected to be the 2nd most favorably impacted(28% top box)
- 44% of business customers felt the electric rate would worsen(bottom box)-only 7% felt it would improve
- 29% of business customers felt the jobless rate in Colorado Springs would worsen(bottom box)-only 7% felt it would improve

If the Drake Power Plant were closed, how would CSU replace the electricity lost?

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Question:
If the Drake Power plant were closed, which would be most likely to happen in order to replace the electricity production lost by the closure?

Residential Results

- Power would be purchased(top box, 10 pt) 46%
- A new power plant would be built(top box, 10 pt) 36%
- With both cases, 6% did not know

Business Results

- Power would be purchased(top box, 10 pt) 41%
- A new power plant would be built(top box, 10 pt) 25%
- With both cases, 20-30% did not know

Are you reducing electricity use?

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Question:
Do you believe you are currently doing everything possible to reduce the use of electricity in your home or business?

Residential Results

• Yes	67.4%
• No	31.1%
• Don't know *(Not Read)*	1.4%

Business Results

• Yes	60.0%
• No	34.0%
• Don't know *(Not Read)*	7.0%

How are you reducing electricity use?

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Question:
What measures are you taking to ensure you are doing all that you can do to reduce your electric usage?

• Turn the lights off	51.3%
• Turn off items not using/ Use less	30.5%
• Using LED Light bulbs/ Energy saving bulbs/ CFL	25.8%
• Heating/ Cooling set temps/ Times	19.1%
• Use less heat	13.1%
• Energy saving appliances	12.7%
• Unplug electric cords	9.7%
• Energy efficient windows	8.1%
• Don't let the water run	6.8%
• Insulation	5.9%
• Wash with full loads of clothes	3.4%

What sources are there to learn about reducing electric usage?

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Question:
Where would you go to learn what else you could do to reduce the use of electricity in your home?

• Internet/ Online	30.9%
• CSU.org/ CSU Website	22.0%
• Colorado Springs Utilities/ CSU	12.3%
• Google	6.6%
• Flyers/ pamphlet	4.9%
• Other methods	23.3%

Questions?

- Are there additional questions you would like us to ask our customers?

Appendix C – Public Feedback Dot Charts

STATION ONE – LOAD AND FUEL PRICES

How much energy will we use now and in 30 years and what will it cost to have the fuel to provide it?

The driving factor in energy planning is how much energy is used – or the demand that's placed on a system. As population and the economy grows, will the electric demand also grow or will the increasing efficiency of technology and changes in customer behavior work to keep demand flat or declining? The scenarios in this group reflect a variety of conditions, from relatively flat growth and fuel prices, to high load growth and high fuel prices.

LOAD GROWTH:

FUEL PRICES:

Questions:

What do you think Springs Utilities should plan for?

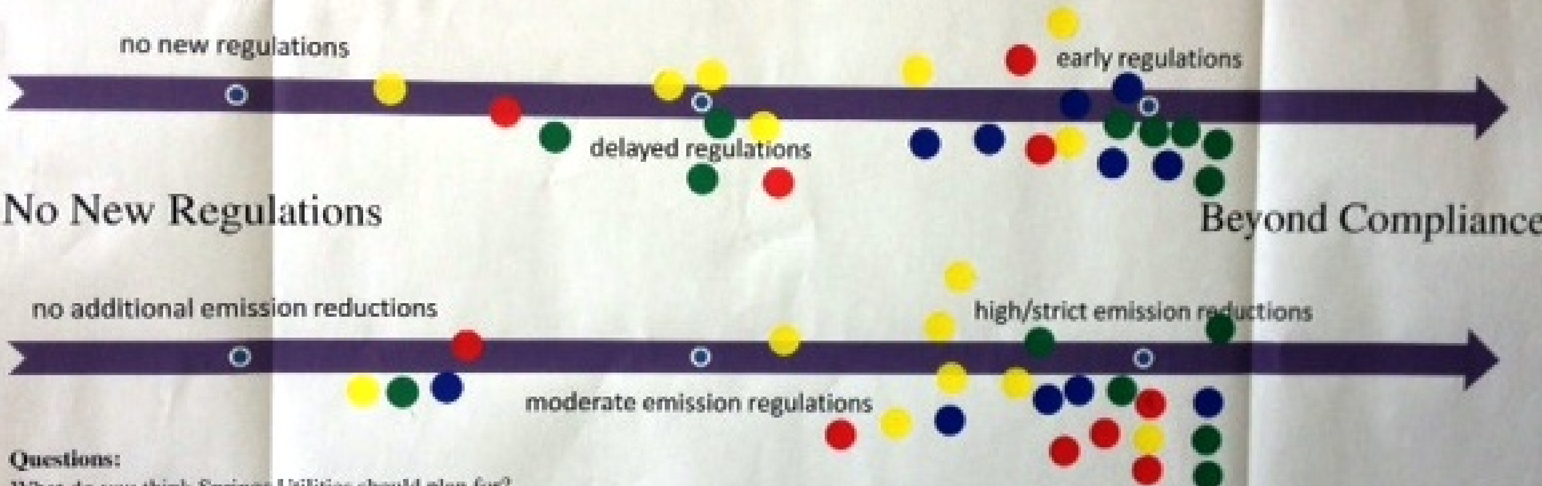
Why did you pick that point?

What are we missing?

STATION TWO – ENVIRONMENTAL REGULATIONS

What impact will environmental regulations have on our decision-making?

Environmental regulations drive many operational and capital decisions. The Environmental Protection Agency (EPA) has proposed the Clean Power Plan to reduce carbon dioxide emissions from power plants, and could also require future reductions of oxides of nitrogen. Will these regulations be implemented on the schedules proposed, or will they be delayed? What level of reduction will be required in final rules and plans?



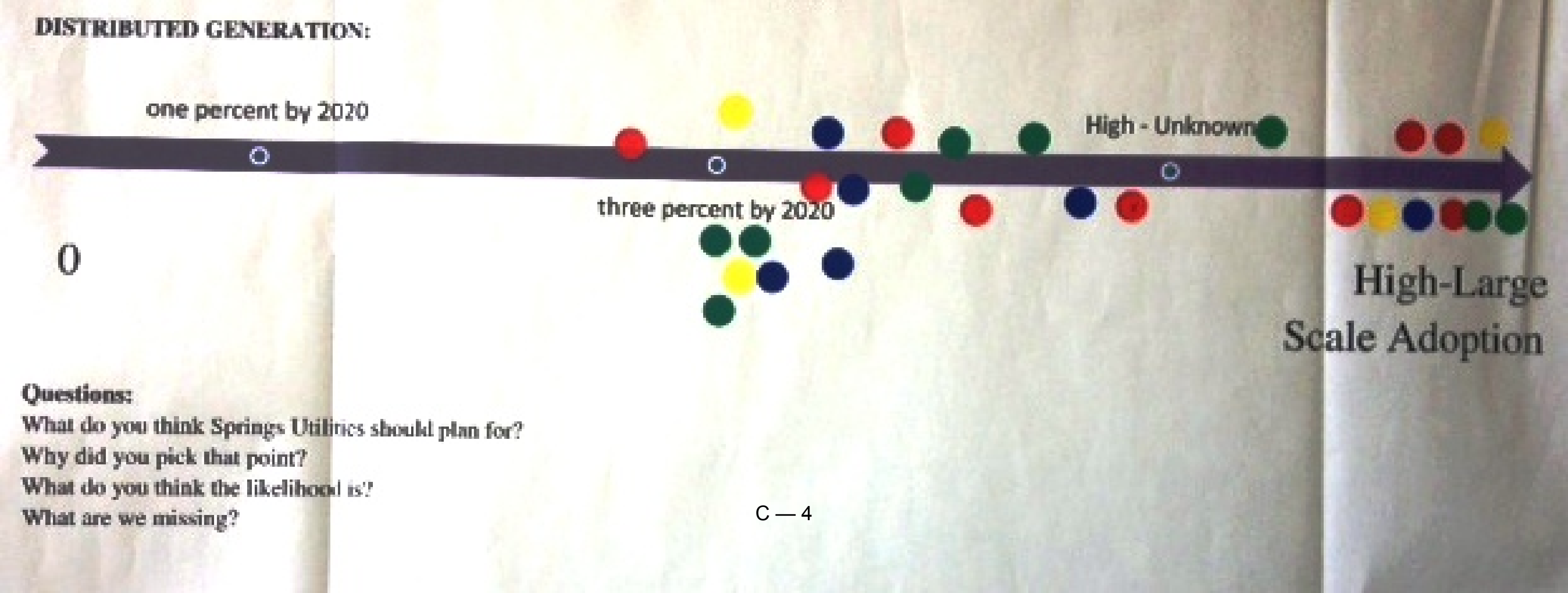
Questions:

What do you think Springs Utilities should plan for?

Why did you pick that point?

What do you think the likelihood is?

What are we missing?


DISTRIBUTED GENERATION:
one percent by 2020
High - Unknown
three percent by 2020
0
High-Large
Scale Adoption
Questions:
What do you think Springs Utilities should plan for?
Why did you pick that point?
What do you think the likelihood is?
What are we missing?

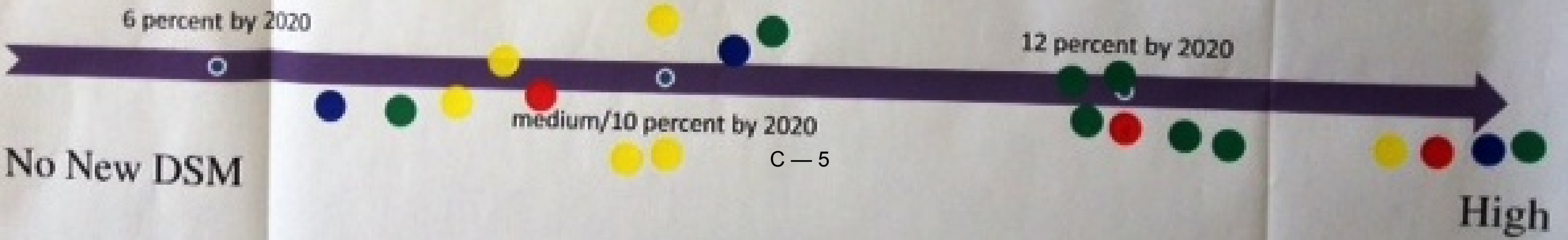
STATION THREE-RENEWABLE ENERGY/DSM/DISTRIBUTED GENERATION

Can we do more or less renewable and DSM and what is the trade-off?
As a utility how do we prepare and respond to increases in distributed generation?

Colorado Springs Utilities uses renewable and traditional energy fuels in its overall portfolio. In 2011, Colorado Springs Utilities created an Energy Vision to have 20 percent of its portfolio be renewable energy by 2020. In addition, we committed to provide opportunities for customers to reduce energy usage by 10 percent through demand-side management (energy efficiency) programs by 2020. Those goals are voluntary, but Springs Utilities must adhere to Renewable Energy Portfolio Standards as mandated by the State of Colorado, which states that we must have 10 percent of our portfolio come from renewable resources by 2020, with incremental milestones. What do our customers prefer? Distributed generation or decentralized generation comes from smaller, more flexible units not connected to a main system and is commonly from renewable energy sources.

RENEWABLE ENERGY:

DEMAND SIDE MANAGEMENT:



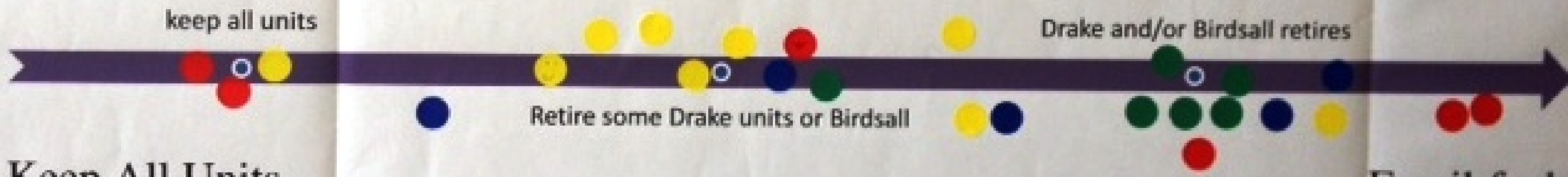
STATION FOUR-FOSSIL-FUELED POWER PLANT DECOMMISSIONING

Do we remain business as usual, or do we retire individual units or retire entire power plants?

Drake Power Plant has been supplying energy to Colorado Springs residents since 1925. Today it contains three units that are primarily fueled by coal. It provide one-third of our overall energy. In 2013, a task force was formed to review alternatives to retiring the plant and how to replace its generation. In 2013, a Drake S was completed by HDR Engineering to provide an understanding of the range of options and trade-offs. Future scenarios offer a glimpse of closing Drake entirel by units.

Birdsall Power Plant was built in 1953 and primarily uses natural gas and diesel. It's mainly used when demand is peaking. Scenarios will consider the future of facility as well.

FOSSIL-FUELED POWER PLANTS:



Keep All Units

Fossil-fuele
Power Plants Gon

Questions:

What do you think Springs Utilities should plan for?

Why did you pick that point?

What do you think the likelihood is?

What are we missing?

Appendix D – Complete Scenario Matrix

EIRP Scenarios Final - July 29, 2015

#	Scenario	10 Yr Net Present Value $ million	20 Yr Net Present Value $ million	10 Yr NPV Diff from Ref	20 Yr NPV Diff from Ref	D5 Decom Date	D6 Decom Date	D7 Decom Date	Portfolio	Load Forecast	DSM Percent of kWh Sales by 2020	RPS Renewables Percent by 2020	DG Percent of Retail Sales per Year	CO2 Reduction Compared to 2005 Baseline	NOx Control Required Year	Gas and Electric Market Price	Coal Price
1	Reference Case - All Drake Units	3,487	6,316	0	0	-	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
2	High Load Growth	3,691	6,734	204	419	-	-	-	G	High	6%	10%	1%	None	2023	Medium	Medium
3	Low Load Growth	3,311	5,972	(176)	(344)	-	2017	-	E	Low	6%	10%	1%	None	2023	Medium	Medium
4	Flat Load Growth - Trend Based	3,404	6,005	(83)	(311)	2018	-	-	E	Flat	6%	10%	1%	None	2023	Medium	Medium
5	Declining Load - Trend Based	3,308	5,598	(179)	(718)	2023	2023	-	E	Declining	6%	10%	1%	None	2023	Medium	Medium
6	Clean Power Plan I – P2 1% per year	3,619	6,694	132	378	2018	2020	-	H	Medium	6%	10%	1%	43% by 2030, 54% by 2050	2023	Medium	Medium
7	Clean Power Plan II – P2 80% by 2050*	3,629	6,720	141	404	2018	2020	-	H	Medium	6%	10%	1%	45% by 2030, 84% by 2050	2023	Medium	Medium
8	Glideslope I – P2 1% per year	3,524	6,487	37	171	2018	2023	-	H	Medium	6%	10%	1%	34% by 2030, 47% by 2050	2023	Medium	Medium
9	Glideslope II– P2 80% by 2050**	3,524	6,484	37	168	2018	2023	-	H	Medium	6%	10%	1%	34% by 2030, 80% by 2050	2023	Medium	Medium
10	No NOx Requirement in 2023	3,403	6,129	(85)	(187)	-	-	-	A	Medium	6%	10%	1%	None	None	Medium	Medium
11	Delayed NOx Requirement - All Drake Units	3,400	6,256	(87)	(59)	-	-	-	A	Medium	6%	10%	1%	None	2026-2028	Medium	Medium
12	Medium DSM	3,456	6,304	(31)	(12)	2018	-	-	F	Medium	10%	10%	1%	None	2023	Medium	Medium
13	Medium DSM with Bill Impact Cap 2%	3,446	6,268	(41)	(48)	2018	-	-	F	Medium	10% Capped	10%	1%	None	2023	Medium	Medium
14	High DSM	3,445	6,269	(42)	(47)	2018	-	-	E	Medium	12%	10%	3%	None	2023	Medium	Medium
15	Clean Power Plan DSM	3,465	6,427	(23)	111	2018	-	-	E	Medium	1.5% per year	10%	1%	None	2023	Medium	Medium
16	No New DSM	3,535	6,399	48	83	-	-	-	A	Medium	No New	10%	1%	None	2023	Medium	Medium
17	Energy Vision	3,687	6,547	200	231	2018	-	-	G	Medium	10%	20%	1%	None	2023	Medium	Medium
18	Energy Vision - Solar at CSR with 3x Multiplier Built	3,667	6,526	179	210	2018	-	-	G	Medium	10%	20%	1%	None	2023	Medium	Medium
19	Energy Vision Case - Wind PTC Available Through 2030	3,685	6,545	197	229	2018	-	-	G	Medium	10%	20%	1%	None	2023	Medium	Medium
20	UPAC Energy Vision	3,510	6,290	23	(26)	2018	-	-	H	Medium	10% Capped	20% Capped	1%	None	2023	Medium	Medium
21	High Energy Vision (IOU Levels)	3,862	6,816	375	500	2018	2023	-	I	Medium	12%	30%	3%	None	2023	Medium	Medium
22	PPACG Sustainability Plan	3,804	6,822	316	506	2018	2018	2023	I	Flat	10%	50% by 2030	1%	None	2023	Medium	Medium
23	No Minimum Renewable Requirement	3,456	6,297	(31)	(19)	2018	-	-	E	Medium	10%	No RPS	1%	None	2023	Medium	Medium
24	High DG Without Incentives	3,461	6,229	(26)	(87)	2023	-	-	F	Medium	6%	10%	High	None	2023	Medium	Medium

EIRP Scenarios Final - July 29, 2015

#	Scenario	10 Yr Net Present Value $ million	20 Yr Net Present Value $ million	10 Yr NPV Diff from Ref	20 Yr NPV Diff from Ref	D5 Decom Date	D6 Decom Date	D7 Decom Date	Portfolio	Load Forecast	DSM Percent of kWh Sales by 2020	RPS Renewables Percent by 2020	DG Percent of Retail Sales per Year	CO2 Reduction Compared to 2005 Baseline	NOx Control Required Year	Gas and Electric Market Price	Coal Price
25	High Commodity Prices - Reference Expansion Plan	3,681	6,780	194	464	-	-	-	A	Medium	6%	10%	1%	None	2023	High	High
26	Low Commodity Prices - Reference Expansion Plan	3,310	5,875	(178)	(440)	-	-	-	A	Medium	6%	10%	1%	None	2023	Low	Low
27	No Coal Availability After 2034 and High Coal Prices	3,556	6,670	69	354	2018	2034	2034	F	Medium	6%	10%	1%	None	2023	Medium	None After 2034
28	Birdsall Decommissioning - 2018	3,485	6,330	(2)	14	-	-	-	B	Medium	6%	10%	1%	None	2023	Medium	Medium
29	Drake 5 Decommissioning - 2018	3,474	6,324	(13)	8	2018	-	-	F	Medium	6%	10%	1%	None	2023	Medium	Medium
30	Drake 5 Firm Gas - 2018	3,515	6,389	28	73	-	-	-	C	Medium	6%	10%	1%	None	2023	Medium	Medium
31	Drake 5 DSI for HCl Only - 2018	3,490	6,334	3	18	-	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
32	Drake 6 and 7 Decommissioning - 2018	3,711	6,663	223	347	-	2018	2018	I	Medium	6%	10%	1%	None	2023	Medium	Medium
33	Nixon 1 Decommissioning - 2018	3,709	6,694	222	378	-	-	-	G	Medium	6%	10%	1%	None	2023	Medium	Medium
34	Drake 5 Decommissioning - 2020	3,481	6,325	(6)	9	2020	-	-	F	Medium	6%	10%	1%	None	2023	Medium	Medium
35	Drake 6 Decommissioning - 2020	3,489	6,360	2	44	-	2020	-	F	Medium	6%	10%	1%	None	2023	Medium	Medium
36	Drake 7 Decommissioning - 2020	3,555	6,473	68	158	-	-	2020	G	Medium	6%	10%	1%	None	2023	Medium	Medium
37	Drake 5 & 6 Decommissioning - 2020	3,538	6,422	51	106	2020	2020	-	I	Medium	6%	10%	1%	None	2023	Medium	Medium
38	Drake Plant Decommissioning - 2020	3,703	6,635	216	319	2020	2020	2020	I	Medium	6%	10%	1%	None	2023	Medium	Medium
39	Drake 5 Decommissioning - 2023	3,476	6,331	(11)	16	2023	-	-	F	Medium	6%	10%	1%	None	2023	Medium	Medium
40	Drake 6 Decommissioning - 2023	3,487	6,357	(0)	41	-	2023	-	F	Medium	6%	10%	1%	None	2023	Medium	Medium
41	Drake 7 Decommissioning - 2023	3,547	6,459	60	143	-	-	2023	D	Medium	6%	10%	1%	None	2023	Medium	Medium
42	Drake 5 & 6 Decommissioning - 2023	3,522	6,404	34	88	2023	2023	-	D	Medium	6%	10%	1%	None	2023	Medium	Medium
43	Drake Plant Decommissioning - 2023	3,561	6,556	74	240	2023	2023	2023	I	Medium	6%	10%	1%	None	2023	Medium	Medium
44	Drake 5 Decommissioning - 2029	3,487	6,349	0	33	2029	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
45	Drake 6 Decommissioning - 2029	3,488	6,379	0	63	-	2029	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
46	Drake 7 Decommissioning - 2029	3,489	6,455	1	139	-	-	2029	D	Medium	6%	10%	1%	None	2023	Medium	Medium
47	Drake 5 & 6 Decommissioning - 2029	3,487	6,430	0	115	2029	2029	-	D	Medium	6%	10%	1%	None	2023	Medium	Medium
48	Drake Plant Decommissioning - 2029	3,488	6,560	1	244	2029	2029	2029	A	Medium	6%	10%	1%	None	2023	Medium	Medium
49	Drake 5 Decommissioning - 2039	3,487	6,321	0	5	2039	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
50	Drake 6 Decommissioning - 2039	3,487	6,321	0	5	-	2039	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
51	Drake 7 Decommissioning - 2039	3,487	6,331	0	15	-	-	2039	A	Medium	6%	10%	1%	None	2023	Medium	Medium
52	Drake 5 & 6 Decommissioning - 2039	3,487	6,323	0	7	2039	2039	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
53	Drake Plant Decommissioning - 2039	3,487	6,317	0	1	2039	2039	2039	A	Medium	6%	10%	1%	None	2023	Medium	Medium
54	Drake 5, 6, and 7 Decommissioning in 2020, 2023, 2029	3,527	6,525	40	210	2020	2023	2029	H	Medium	6%	10%	1%	None	2023	Medium	Medium
55	Clean Power Plan II with High Gas Prices	3,849	7,350	362	1,034	2020	2020	2023	I	Medium	6%	10%	1%	45% by 2030, 84% by 2050	2023	High	High
56	Clean Power Plan II with Forced DSM and Renewable Building Blocks	3,723	6,794	236	478	2018	2018	2023	I	Medium	1.5% per year	20%	1%	45% by 2030, 84% by 2050	2023	Medium	Medium
57	Energy Vision - High Commodity Prices	3,853	6,944	366	628	2018	-	-	G	Medium	10%	20%	1%	None	2023	High	High
58	Energy Vision - Low Commodity Prices	3,533	6,171	46	(145)	2018	-	-	G	Medium	10%	20%	1%	None	2023	Low	Low
59	No Minimum Renewable Requirement - High Commodity	3,652	6,782	165	466	2018	-	-	E	Medium	10%	No RPS	1%	None	2023	High	High
60	No Minimum Renewable Requirement - Low Commodity	3,276	5,840	(212)	(476)	2018	-	-	E	Medium	10%	No RPS	1%	None	2023	Low	Low

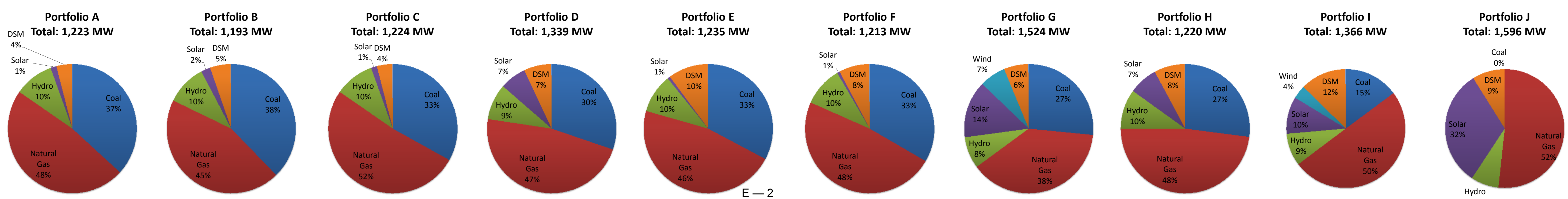
EIRP Scenarios Final - July 29, 2015

#	Scenario	10 Yr Net Present Value $ million	20 Yr Net Present Value $ million	10 Yr NPV Diff from Ref	20 Yr NPV Diff from Ref	D5 Decom Date	D6 Decom Date	D7 Decom Date	Portfolio	Load Forecast	DSM Percent of kWh Sales by 2020	RPS Renewables Percent by 2020	DG Percent of Retail Sales per Year	CO2 Reduction Compared to 2005 Baseline	NOx Control Required Year	Gas and Electric Market Price	Coal Price
61	High Water Cost - For Illustrative Purposes Only (not a prediction of future water rates)	3,506	6,352	19	36	-	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
~~62~~	~~Low Hydro Output Drought~~ Reference hydro conditions are low, contract extended so very low risk of losing this capacity									~~Medium~~	~~6%~~	~~10%~~	~~1%~~	~~None~~	~~2023~~	~~Medium~~	~~Medium~~
~~63~~	~~Drake 5 Decommissioning - 2018~~ Scenario 12 shows the it is economic to decommission D5 in 2018 with 10% DSM - no need to run additional scenario with flat load									~~Flat~~	~~10%~~	~~10%~~	~~1%~~	~~None~~	~~2023~~	~~Medium~~	~~Medium~~
64	Birdsall Decommissioning - 2018 Flat Load and Medium DSM	3,426	6,049	(61)	(267)	2018	2023	-	F	Flat	10%	10%	1%	None	2023	Medium	Medium
65	DSM as a Potential Resource	3,457	6,295	(30)	(21)	2023	-	-	F	Medium	6% + Select	10%	1%	None	2023	Medium	Medium
66	UPAC Energy Vision with Glideslope I (Medium Load)	3,511	6,421	24	105	2018	2020	-	H	Medium	10% Capped	20% Capped	1%	34% by 2030, 47% by 2050	2023	Medium	Medium
67	Energy Vision to 2030	3,772	6,753	285	437	2018	-	-	G	Medium	10%	30% by 2030	1%	None	2023	Medium	Medium
68	Clean Power Plan II – P2 80% by 2050* with High 12% DSM	3,514	6,535	26	219	2018	2018	-	I	Medium	12%	10%	3%	45% by 2030, 84% by 2050	2023	Medium	Medium
69	Energy Statement	3,431	5,681	(56)	(635)	2018	2018	2023	I	Declining	No New	10%	High	45% by 2030, 84% by 2050	2023	Medium	Medium
70	Energy Statement with DSM, RPS and High Fuel Prices	3,615	6,399	127	83	2018	2018	2018	I	Declining	1.5% per year	20%	High	45% by 2030, 84% by 2050	2023	High after 2027	None After 2034
71	Drake 5 Distribution Natural Gas Instead of SCR - 2023	3,475	6,301	(12)	(15)	-	-	-	A	Medium	6%	10%	1%	None	2023	Medium	Medium
72	Drake 5 Firm Distribution Natural Gas - 2018	3,474	6,298	(13)	(18)	-	-	-	C	Medium	6%	10%	1%	None	2023	Medium	Medium
73	High Commodity Prices - New Expansion Plan	3,687	6,853	200	537	-	-	-	A	Medium	6%	10%	1%	None	2023	High	High
74	Low Commodity Prices - New Expansion Plan	3,282	5,839	(205)	(477)	2018	-	-	F	Medium	6%	10%	1%	None	2023	Low	Low
75	Energy Vision - Solar at CSR with 3x Multiplier Built and Wind PTC Available Through 2030	3,652	6,499	165	183	2018	-	-	G	Medium	10%	20%	1%	None	2023	Medium	Medium
76	Drake 5, 6, and 7 Decommissioning in 2018, 2023, 2029	3,522	6,514	35	198	2018	2023	2029	H	Medium	6%	10%	1%	None	2023	Medium	Medium
77	Drake 5, 6, and 7 Decommissioning in 2018, 2023, 2029 UPAC Energy Vision with Glideslope I	3,506	6,514	18	198	2018	2023	2029	H	Medium	10% Capped	20% Capped	1%	34% by 2030, 47% by 2050	2023	Medium	Medium
78	Drake 5, 6, and 7 Decommissioning in 2018, 2023, 2029 Clean Power Plan II	3,598	6,722	111	407	2018	2023	2029	H	Medium	6%	10%	1%	45% by 2030, 84% by 2050	2023	Medium	Medium
79	Drake 5, 6, and 7 Decommissioning in 2018, 2023, 2029 Glideslope I	3,523	6,596	36	280	2018	2023	2029	H	Medium	6%	10%	1%	34% by 2030, 47% by 2050	2023	Medium	Medium
80	Clean Power Plan II – No NOx Requirement in 2023	3,577	6,562	90	246	2018	2023	-	H	Medium	6%	10%	1%	45% by 2030, 84% by 2050	None	Medium	Medium
81	Glideslope I – No NOx Requirement in 2023	3,427	6,329	(60)	13	2018	2027	-	H	Medium	6%	10%	1%	45% by 2030, 84% by 2050	None	Medium	Medium
82	Drake Plant Decommissioning - 2018	3,722	6,647	235	331	2018	2018	2018	I	Medium	6%	10%	1%	None	2023	Medium	Medium
83	UPAC Energy Vision - Drake 5 Distribution Gas 2018 (allow shutdown as well)	3,517	6,269	30	(47)	-	-	-	D	Medium	10% Capped	20% Capped	1%	None	2023	Medium	Medium
84	High DSM - Drake 5 Distribution Gas 2018 (allow shutdown as well)	3,438	6,256	(50)	(60)	-	-	-	E	Medium	12%	10%	3%	None	2023	Medium	Medium
85	High Energy Vision with CPPII and 20% RPS	3,597	6,290	110	(26)	2018	2018	2020	I	Flat	12%	20%	HIgh	45% by 2030, 84% by 2050	2023	Medium	Medium

Appendix E – Portfolio Options Large-Scale

	Portfolio A Low DSM All Units Online	Portfolio B Birdsall Decommissioning	Portfolio C Low DSM Drake 5 Natural Gas	Portfolio D UPAC Energy Vision Drake 5 Natural Gas	Portfolio E High DSM Drake 5 Natural Gas	Portfolio F Medium DSM with a Spending Cap	Portfolio G Energy Vision to 2030	Portfolio H UPAC Energy Vision Phased Drake Plant Decommissioning	Portfolio I Short-Term Drake Decommissioning	Portfolio J Coal Removed by 2023 and 50% Renewable by 2030
2018	Drake 5 Coal Invest In SO2 Control Invest in NOx Control	Drake 5 Coal Invest In SO2 Control Invest in NOx Control	Drake 5 Natural Gas Invest in NOx Control	Drake 5 Natural Gas Invest in NOx Control	Drake 5 Natural Gas Invest in NOx Control	Drake 5 Decommission	Drake 5 Decommission	Drake 5 Decommission	Drake Plant Decommission 2018 2018 2020	Drake Plant Decommission 2018 2018 2020
	Birdsall Online	Birdsall Decommission	Birdsall Online	Birdsall Online	Birdsall Decommission	Birdsall Online	Birdsall Online	Birdsall Online	Birdsall Online	Birdsall Online
	6% DSM	6% DSM	6% DSM	10% DSM Bill Impact Cap	12% DSM	10% DSM Bill Impact Cap	10% DSM	10% DSM Bill Impact Cap	12% DSM	12% DSM
	10% Renewable by 2020	10% Renewable by 2020	10% Renewable by 2020	20% Renewable by 2020 Bill Impact Cap	10% Renewable by 2020	10% Renewable by 2020	20% Renewable by 2020 30% Renewable by 2030	20% Renewable by 2020 Bill Impact Cap	20% Renewable by 2020	50% Renewable by 2030
2020 - 2029	Option to Invest in Additional NOX Control: Drake 5, 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 5, 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 6, 7 and Nixon 1	Option to Invest in Additional NOX Control: Drake 6, 7 and Nixon 1	Drake 6 Decommission 2023 Option to Invest in Additional NOX Control: Drake 7 and Nixon 1	Option to Invest in Additional NOX Control: Nixon 1	Nixon 1 Decommission
2029								Drake 7 Decommission		

2025 Installed Capacity



Appendix F – Complete Evaluation Matrix

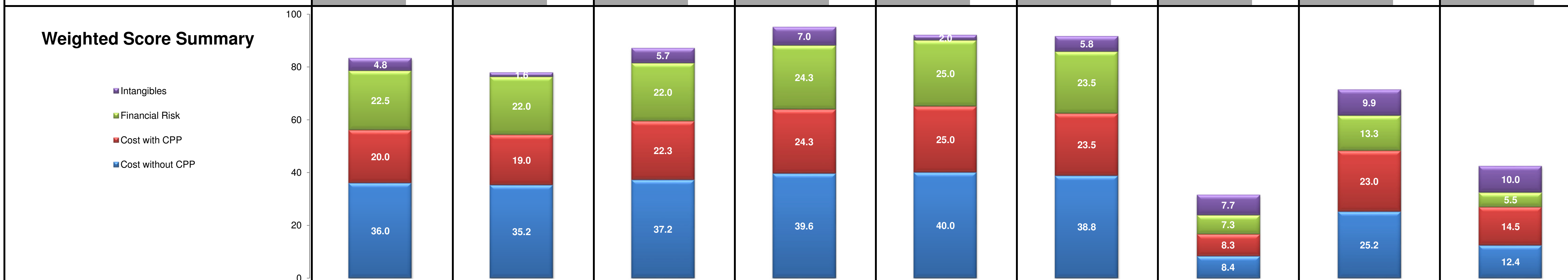
2015 Electric Integrated Resource Plan Portfolio Evaluation Matrix

Portfolios are scored with a total of 100 points available per metric then weighted for a total maximum portfolio score of 100-- the higher the score the better the portfolio

Metric	Measure	Weight	Portfolio A 6% DSM 10% Renewable Drake 5 Coal			Portfolio B 6% DSM 10% Renewable Drake 5 Coal Birdsall Decommissioning			Portfolio C 6% DSM 10% Renewable Drake 5 Natural Gas		
			Value	Score	Wtd Score	Value	Score	Wtd Score	Value	Score	Wtd Score
Cost without Clean Power Plan	NPV of Revenue Requirement $Millions	40%	$6,316	90	36.0	$6,330	88	35.2	$6,298	93	37.2
Cost with Clean Power Plan Best Estimate for Springs Utilities Pending State Plan	NPV of Revenue Requirement $Millions	25%	$6,549	80	20.0	$6,574	76	19.0	$6,492	89	22.3
Financial Risk Uncertainty for Demand, Natural Gas Fuel Prices, and Electric Market Commodity Prices	95th Percentile NPV of Revenue Requirement $Millions	25%	$6,503	90	22.5	$6,517	88	22.0	$6,514	88	22.0
Intangibles: Dispatchability; Portfolio Diversity; Societal Benefits; Customer Resource Preference; Development Risk; Transmission Reliance	Weighted Decision Matrix Score	10%	171	48	4.8	143	16	1.6	179	57	5.7
Total Weighted Score					83			78			87

Metric	Measure	Weight	Portfolio D 10% DSM Capped 20% Renewable Capped Drake 5 Natural Gas			Portfolio E 12% DSM 10% Renewable Drake 5 Natural Gas Birdsall Decommissioning			Portfolio F 10% DSM Capped 10% Renewable Drake 5 Decommissioning		
			Value	Score	Wtd Score	Value	Score	Wtd Score	Value	Score	Wtd Score
Cost without Clean Power Plan	NPV of Revenue Requirement $Millions	40%	$6,264	99	39.6	$6,255	100	40.0	$6,271	97	38.8
Cost with Clean Power Plan Best Estimate for Springs Utilities Pending State Plan	NPV of Revenue Requirement $Millions	25%	$6,440	97	24.3	$6,419	100	25.0	$6,455	94	23.5
Financial Risk Uncertainty for Demand, Natural Gas Fuel Prices, and Electric Market Commodity Prices	95th Percentile NPV of Revenue Requirement $Millions	25%	$6,462	97	24.3	$6,440	100	25.0	$6,476	94	23.5
Intangibles: Dispatchability; Portfolio Diversity; Societal Benefits; Customer Resource Preference; Development Risk; Transmission Reliance	Weighted Decision Matrix Score	10%	190	70	7.0	147	20	2.0	180	58	5.8
Total Weighted Score					95			92			92

Metric	Measure	Weight	Portfolio G 10% DSM 20% Renewable Drake 5 Decommissioning			Portfolio H 10% DSM Capped 20% Renewable Capped Phased Drake Plant Decommissioning			Portfolio I 12% DSM 20% Renewable Short Term Drake Decommissioning by 2020		
			Value	Score	Wtd Score	Value	Score	Wtd Score	Value	Score	Wtd Score
Cost without Clean Power Plan	NPV of Revenue Requirement $Millions	40%	$6,751	21	8.4	$6,486	63	25.2	$6,687	31	12.4
Cost with Clean Power Plan Best Estimate for Springs Utilities Pending State Plan	NPV of Revenue Requirement $Millions	25%	$6,848	33	8.3	$6,472	92	23.0	$6,687	58	14.5
Financial Risk Uncertainty for Demand, Natural Gas Fuel Prices, and Electric Market Commodity Prices	95th Percentile NPV of Revenue Requirement $Millions	25%	$6,897	29	7.3	$6,745	53	13.3	$6,944	22	5.5
Intangibles: Dispatchability; Portfolio Diversity; Societal Benefits; Customer Resource Preference; Development Risk; Transmission Reliance	Weighted Decision Matrix Score	10%	196	77	7.7	215	99	9.9	216	100	10.0
Total Weighted Score					32			71			42



Notes

Portfolio A:
- Low dispatchability risk
- Requires investment in new coal emissions reductions with significant operating costs on Drake 5
- No new generation for nine years
- Minimizes investment in customer conservation
- Minimizes investment in renewable energy
- Does not align with customer preferences
- CPP retires D5 and D6, adds 25 MW natural gas and 100 MW solar

Portfolio B:
- Low dispatchability risk
- Requires investment in new coal emissions reductions with significant operating costs on Drake 5
- Requires investment in voltage reduction project to replace Birdsall capacity
- No new significant generation for at least seven years
- Minimizes investment in customer conservation
- Minimizes investment in renewable energy
- Does not align with customer preferences
- CPP retires D5, adds 25 MW natural gas and 80 MW solar

Portfolio C:
- Low dispatchability risk
- Requires investment in new gas burners on Drake 5
- Investment in small biogas project within nine years
- Drake 5 available for generation if needed
-Minimizes investment in customer conservation
-Minimizes investment in renewable energy
-Does not align with customer preferences
-CPP retires D6, adds 80 MW solar and voltage reduction project

Portfolio D:
- Second least cost portfolio, within 0.1-0.3% of Portfolio E
- Requires investment in new gas burners on Drake 5
- Aligns with customer preference for increased conservation and renewables
- Includes bill impact cap of 1% for renewable and 2% for DSM ensuring cost control
- Moderate dispatchability risk
- Drake 5 available for generation if needed
- CPP retires D6, moves up voltage reduction project and adds customer demand response programs
- Flexible, diverse portfolio that reduces risk related to demand increases
- Very similar first 5 years as Portfolio H allowing a transition later
- Low development risk

Portfolio E:
- Least cost portfolio monetarily
- Requires investment in new gas burners on Drake 5
- Relies on very high level of customer conservation to replace Birdsall capacity
- No new generation for at least 15 years
- CPP retires D6, adds 20 MW solar and moves up voltage reduction project
- Does not align with customer preference for renewables
- Lacks diversity by comparison
- Moderate development and dispatchability risk related to high DSM
- Would need new resources after 2023 to optimize cost for CPP
- Minimizes investment in renewable energy

Portfolio F:
- Third least cost portfolio, within 0.3-0.6% of Portfolio E
- Drake 5 decommissioned
- No new generation for at least eight years
- Aligns with customer preference for conservation
- Some dispatchability risk
- Lower diversity related to unit decommission and low renewable additions
- CPP retires D6, adds 170 MW solar and voltage regulation project
- Minimizes investment in renewable energy

Portfolio G:
- High diversity
- High dispatchable capacity risk related to high intermittent generation
- No resources additions needed to meet CPP
- Highest cost of all portfolios
- Moderate development risk related to medium DSM

Portfolio H:
- One of the least cost options with the CPP
- Moderate dispatchability risk
- Aligns with customer preference for adding DSM and renewable
- Includes bill impact cap of 1% for renewable and 2% for DSM ensuring cost control
- High societal benefits for city image and emissions
- Low development risk

Portfolio I:
- High dispatchability risk, decreases availability of power on demand
- High societal benefits, diversity, and customer resource preference
- Relies on high level of customer conservation
- Requires investment in 97 MW new natural gas capacity
- Adds 130 MW solar and 50 MW wind by 2020

Note: Portfolio J was not scored due to much higher cost

Appendix G – Approval Process

Colorado Springs Utilities
It's how we're all connected

Regulatory Approval

The Chief Executive Officer of Colorado Springs Utilities is authorized to execute this Electric Integrated Resource Plan on behalf of Colorado Springs Utilities pursuant to Colorado Springs City Charter Article VI; Chapter 12 of the City Code of the City of Colorado Springs; and Colorado Springs Utilities Board Policies.

This 2016 Electric Integrated Resource Plan is approved.

Jerry Forte, P.E.

Chief Executive Officer

Department of Energy
Western Area Power Administration
Rocky Mountain Customer Service Region
P.O. Box 3700
Loveland, CO 80539-3003

DEC 0 2 2016

Mr. John Romero
General Manager, Energy Acquisition Engineering and Planning
Colorado Springs Utilities
P.O. Box 1103, Mailstop 1328
Colorado Springs, CO 80947-1328

Dear Mr. Romero:

Thank you for submitting the Colorado Springs Utilities (CSU) Integrated Resource Plan (IRP) to the Western Area Power Administration (WAPA). The IRP has been reviewed and approved. Section 905.13 of the Energy Planning and Management Program (EPAMP) requires that customers submit updated IRPs every five (5) years after WAPA's approval of their initial IRP. Given that CSU has submitted this updated IRP prior to the February 26, 2017, IRP due date, CSU's IRP will be effective until February 26, 2022. Data from WAPA's customers will be consolidated and included in an annual report provided to Congress and others summarizing customers' accomplishments in fulfilling the requirements of the Energy Policy Act of 1992.

Section 905.23 of EPAMP as amended effective July 21, 2008, facilitates public review of customers' IRPs by requiring that a customer's IRP be posted on its publicly available website or on WAPA's website consistent with the Freedom of Information Act (FOIA) exemptions. Upon receipt of a request from CSU, WAPA will determine, consistent with FOIA exemptions, whether specific information contained in CSU's IRP is exempt from public access.

WAPA's Energy Services Web site (https://www.wapa.gov/EnergyServices/IRP/Pages/irp.aspx) provides information on integrated resource planning and minimum investment reporting requirements. If you have questions, please telephone Annette Meredith at (970) 461-7610.

Sincerely,

David Neumayer
Power Marketing Manager

cc:
Mr. Ed Arguello, P.E., CSU

Appendix H – Abbreviations and Acronyms

AGP	advanced gas path
BFB	bubbling fluidized bed boiler
Btu	British thermal unit
CAG	Customer Advisory Group
CCPG	Colorado Coordinated Planning Group
CCS	carbon capture and sequestration
CEMS	Continuous Emissions Monitoring System
CO PUC	Public Utilities Commission for the State of Colorado
CO RES	Colorado Renewable Energy Standard
CO2	carbon dioxide
CPP	Clean Power Plan
CSG	community solar garden
CSR	Clear Spring Ranch
CT	combustion turbine
CVR	conservation voltage reduction
DR	demand response
DSM	Demand-side management
ECA	electric cost adjustment
EGU	electric generating units
EIRP	Electric Integrated Resource Plan
EPA	Environmental Protection Agency
GCA	gas cost adjustment
hydro	hydroelectric
ITC	Investment Tax Credit
LAP	Western's Loveland Area Projects
LDC	local distribution company
MW	megawatt

MWh	megawatt-hours
MWTG	Mountain West Transmission Group
NAAQS	National Ambient Air Quality Standard
NOx	oxides of nitrogen
NPV	net-present value
O&M	operations and maintenance
PaR	ABB's Planning and Risk software
PTC	Production Tax Credit
PV	photovoltaic solar
RECs	Renewable Energy Certificates
scf	standard cubic foot
SCR	Selective Catalytic Reduction
SHDF	Solid Handling Disposal Facility
SIP	State Implementation Plan
SLCA/IP	Western’s Salt Lake City Integrated Area Projects
SMR	small modular nuclear reactor
SO2	sulfur dioxide
SREC	Solar Renewable Energy Credit
SWEEP	Southwest Energy Efficiency Project
ULNB	ultra-low NOx burners
UPAC	Utilities Policy Advisory Committee
USAFA	United States Air Force Academy
WECC	Western Electric Coordinating Council
Western	Western Area Power Administration

Appendix I – Glossary of Terms

ABB Planning and Risk	A production cost model that simulates hourly commitment and dispatch of a resource portfolio to estimate the cost and reliability of operating that portfolio.
ABB System Optimizer	An expansion plan model that considers the long-term electric requirements to produce a least-cost resource plan, or portfolio, for a given scenario.
Baseload Resource	Typically a higher construction, lower operating cost resource that is online a majority of the year serving the base portion of demand that is always needed, e.g. coal and combined-cycle plants.
Contingency Reserves	Capacity kept in reserve, at least half online, used to respond to generating unit outages as needed.
Distributed Generation	Small resources, usually solar, dispersed throughout the distribution system at or near the load. In contrast, traditional resources are typically large, centralized, and located farther from the load relying on transmission and distribution lines to deliver the energy.
Investment Tax Credit	A federal tax credit provided to qualifying renewable energy producers, predominantly solar, provided as a percent of installation cost.
Load Factor	A measurement of system utilization, it is the ratio of average and peak demand.
Monte Carlo Simulation	A method that models a range of possible inputs for uncertain variables and their probability of occurring, like forecasted natural prices, which produces a range of results with the probability of each result.
Peaking Resource	Typically a low construction, high operating cost resource built to be used during only the highest times of demand, e.g. combustion turbines.
Planning Reserve Margin	The amount of generation capacity in excess of the expected demand to ensure Colorado Springs Utilities has the resource adequacy to achieve an industry standard level of loss of load probability (1 day in 10 years) over the long-term considering possible unit outages and unexpected increases in demand.
Portfolio	A combination of supply and demand side electric resources including generators, purchase power contracts and energy efficiency.
Production Tax Credit	A federal tax credit provided to qualifying renewable energy producers, predominantly wind, for each kilowatt-hour of renewable energy generated.

Regulating Reserves	Online capacity used to regulate minute by minute frequency changes.
Scenario	A set of possible future conditions that results in a new electric resource plan.
Smart Grid	A collection of technologies using remote control and automation designed to help consumers and utilities more effectively and efficiently use the electric system.
Stochastic Risk Analysis	Using a Monte Carlo Simulation, the stochastic risk analysis provides a range of results based on multiple iterations that change the input assumptions stochastically, or randomly, within probability distributions based on historical volatility for chosen variables. The results provide insight into the realistic potential range of costs for a portfolio given uncertainties in future conditions.
Weighted Decision Analysis	A method of scoring the more qualitative aspects of each portfolio using various criteria weighted by importance.