2020 GAS INTEGRATED RESOURCE PLAN

Colorado Springs Utilities®

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Executive Summary

Introduction

Colorado Springs Utilities' ("Springs Utilities") 2020 Gas Integrated Resource Plan ("GIRP", "IRP") is a long-term strategic plan for providing cost effective, resilient, and reliable energy resources to meet the energy needs of Springs Utilities' customers from 2020 to 2050.

Springs Utilities developed the GIRP using a three phased approach to gas resource planning that ensures customers are provided with long-term safe, reliable, and cost-effective natural gas service. During each phase of the GIRP study, (shown in Figure GS1) Springs Utilities discussed various aspects of the plan with different stakeholders through a structured public process. The views, ideas and recommendations from stakeholders were incorporated in the plan for each deliverable. At the end of the process, Springs Utilities made a recommendation to the Utilities Board which was subsequently approved.

Figure GS1: GIRP Process

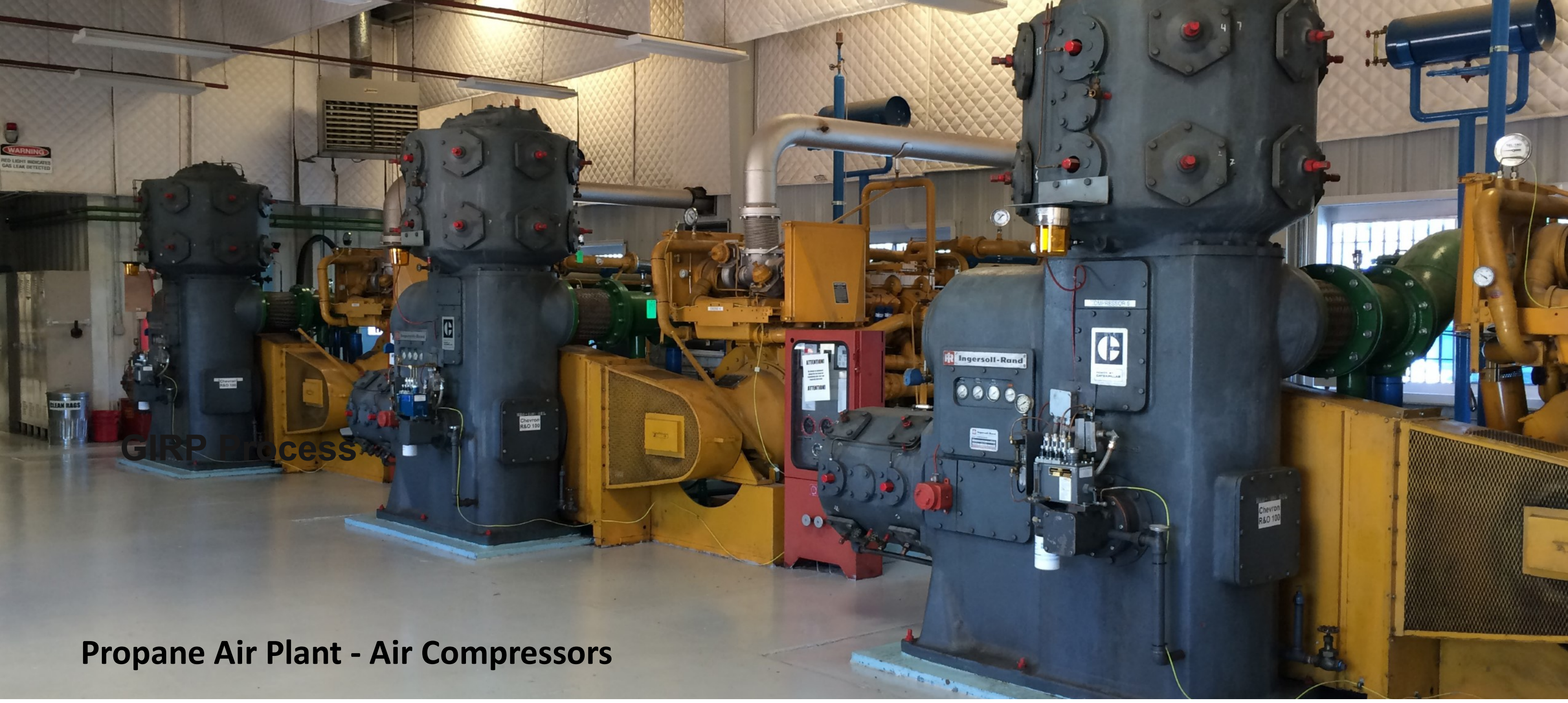
Our Mission	Our Vision	Energy Vision	Pillars of Energy Vision	IRP Goals
Provide safe, reliable, competitively priced electric, natural gas, water, and wastewater services to the citizens and customers of Colorado Springs Utilities	Colorado Springs Utilities is a treasured community partner, well known for providing responsible and dependable services that are vital to the future of our region	Provide resilient, reliable, and cost-effective energy that is environmentally sustainable, reduces our carbon footprint, and uses proven state-of-the-art technologies to enhance our quality of life for generations to come	**Economic -** Cost-effective and equitable initiative that drives a strong economy **Environment -** Sustainable solutions that complement our natural resources **Resiliency -** Reliably withstand and recover from disturbances in a dynamic environment **Innovation -** Proactively and responsibly evolve in a transforming landscape	**Resilient and reliable-** Industry leading reliability and resiliency while avoiding potential stranded assets and supporting economic growth of the region **Cost-effective energy-** Maintain competitive and affordable rates advancing energy efficiency and demand response **Environmentally sustainable-** Grow renewable portfolio and establish timelines for the decommissioning of non-renewable assets **Reduces our carbon footprint -** Meet all environmental regulations with specific metrics that include reducing our carbon footprint and reducing reliance on fossil fuels **Uses proven state-of the-art technologies -** Proactively and responsibly integrate new technologies

Figure GS2: GIRP Guidance

GIRP Guidance

Springs Utilities followed its mission and vision statements, and developed an Energy Vision, pillars, and IRP goals with input from the Utilities Policy Advisory Committee (UPAC) and the public as shown in Figure GS2. The IRP goals were used as a foundation to dictate the planning approach, including development and analysis of inputs, sensitivities, and resource portfolios.

The GIRP process considered various portfolios and recommended a portfolio of existing and new resources that provides a balanced and responsible plan to meet the GIRP objectives; safe, reliable, and cost-effective natural gas service. Based on identified potential resources, detailed studies were performed to choose alternatives best aligned with Springs Utilities' goals while meeting the gas demand forecast.



Propane Air Plant - Air Compressors

GIRP Process

The GIRP process was broken down into three distinct phases that are discussed below. During each phase, Springs Utilities sought public input through surveys, public meetings, and workshops. At the end of each phase, Utilities Board approval was essential to move on to the subsequent phase.

Phase One - GIRP Development

During this phase, the activities of the IRP were broken down into the following three activities: the development of goals (Figure GS2) to provide a foundation for the GIRP, identification of analyses and sensitivities to be performed, and selection of necessary inputs and assumptions for analyses.

Phase One Deliverables

Phase one deliverables included finalizing the reference case assumptions and sensitivities, load forecasts, demand side management potential, and commodity price forecasts. The gas load forecast for the long term horizon was developed considering both customer baseline growth and weather sensitive gas demand. Forecasted customer growth and potential changes in gas usage were modeled by Springs Utilities Planning and Finance Department. Additionally, future peak load for weather sensitivities was established for a one-in-twenty five year cold weather occurrence. Long term load was established through regression based modeling considering growth, usage and weather sensitivities.

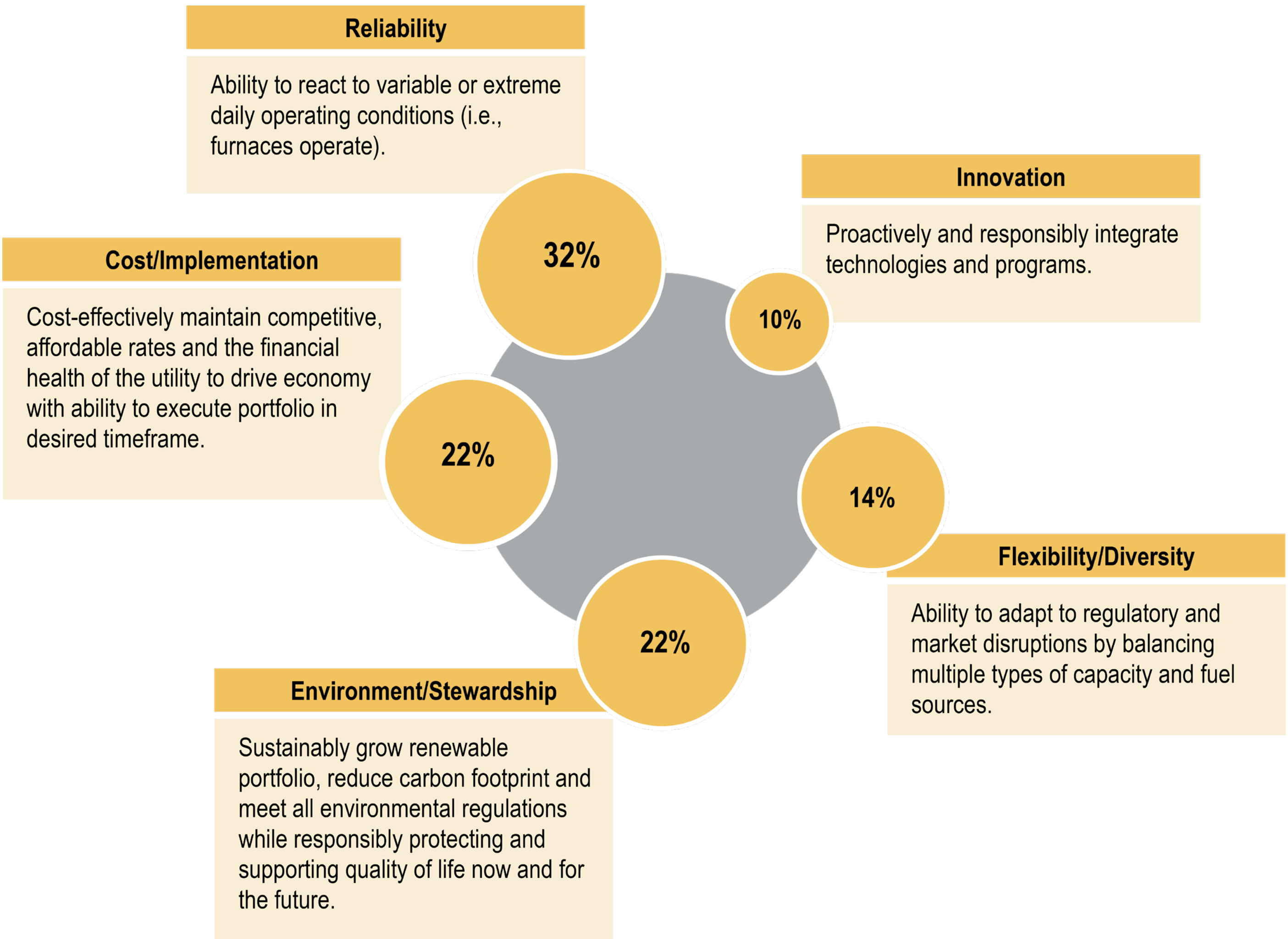
Due largely to local population growth, the customer demand for natural gas in the Springs Utilities coverage area will exceed current pipeline and Springs Utilities propane air capacity starting in the 2032-2033 heating season.

A demand side management potential study was completed by The Cadmus Group. The study included analysis of smart thermostats, water heater direct load control, and critical peak pricing for residential customers and smart thermostats for commercial customers.

Gas commodity pricing for the first five years was established using short term forward pricing. The longer term horizon was establish utilizing the ABB 2019 Spring reference case commodity forecast.

Phase two was comprised of the following three activities: modeling and analysis of each portfolio identified in phase one based upon IRP goals and five weighted attributes: Reliability, Cost/Implementation, Environment/Stewardship, Flexibility/Diversity and Innovation. IRP goals, attributes, and weights were vetted through the public process, UPAC, and the Utilities Board and are shown in Figure GS2 and GS3.

Figure GS3: GIRP Attribute Weighting



Phase Two Deliverables

The 2020 GIRP evaluated resource options needed to meet annual, peak day and peak hour customer demands forecasted thru 2050. Six portfolios were developed in the GIRP with variations of new pipeline capacity, propane air facilities, liquefied natural gas, and demand-side management (DSM) programs. DSM programs were assumed to be developed with a pilot beginning in 2022 with widespread implementation in 2025. Most of the DSM programs are based on a 20-year implementation. All portfolios include expanding the existing propane air plant, since it is the least-cost option to provide additional supply resources. The propane air plant capacity also increases incrementally as customer load increases allowing sufficient blending capacity at the North Gate Station.

After determining various portfolios, pathways were developed to narrow the scope and focus the decision-making process to near-term activities. The six portfolios and four pathways are shown in Table 1 below. Pathways serve to summarize and group together the portfolios based on common characteristics. The GIRP analysis evaluated portfolios and pathways to determine important factors over the next 10 years, while keeping flexibility for long term changes in subsequent GIRPs. Each portfolio falls into a specific pathway, based on New Pipeline Capacity, New Peak Shaving Capacity, or new DSM programs. Overall, four pathways (including the reference case) were identified in the GIRP study, and the six portfolios were assigned to one of the pathways.

Table 1: GIRP Pathways and Portfolios

Pathway	Reference	A - New Pipeline Capacity	B - New Peak Shaving Capacity	C - DSM + New Peak Shaving Capacity		
Portfolio	1	2	3	4	5	6
2022						
2025		Energy Efficiency	Energy Efficiency	Demand Response	Energy Efficiency	DR + EE
2030						
2032	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion
2034	New Propane Air	Expand/New Pipeline Capacity	New LNG Plant		New Propane Air	
2035						
2040	Expand Propane Air		Expand LNG Plant	New Propane Air		New Propane Air
2043					Expand Propane Air	
2050	Expand/New Pipeline Capacity			Expand/New Pipeline Capacity		

Phase Three – GIRP Course of Action

Phase Three of the GIRP process included the development of a course of action based on the analysis and results collected in the first two phases of the GIRP. The main activities of Phase Three included developing the weighted attribute scores of the portfolios from Phase Two. Based upon the weighted score of the portfolios and in discussions with various stakeholders, the top three portfolios were identified. A selection of the preferred portfolio was done in discussions with stakeholders and approved by Utilities Board.

Phase Three Deliverables

The six portfolios were evaluated based on the attribute weighting established earlier in the GIRP process. A normalized score was determined for each portfolio. Table 2 shows the attribute scores for each portfolio. The grey cells in the table indicate the portfolio with the highest score for each attribute. Each portfolio was evaluated using net present value and revenue requirement methodology on a 30-year horizon. The 30-year revenue requirement for each portfolio is included below in Table 3. After the initial portfolio evaluation, portfolios 1, 4, and 6 were identified for further refinement.

Table 2: Portfolio Attribute Scoring

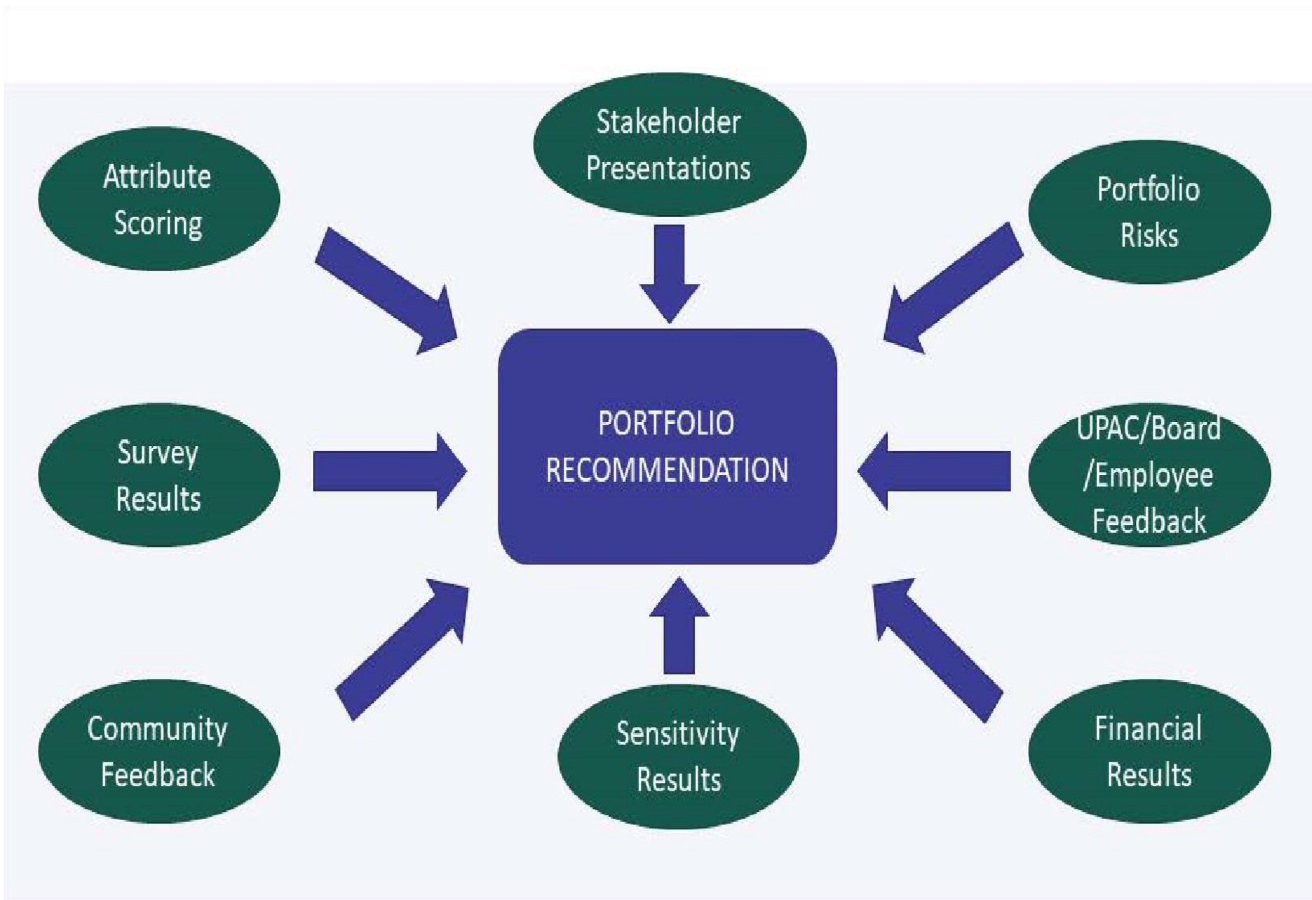
Portfolio	Pathway	New Resources	Attribute Ranking	Normalized Score	Reliability	Cost/ Implementation	Environmental Stewardship	Flexibility/Diversity	Innovation
6	C	Demand Response, Energy Efficiency, PAP Expansion, New PAP	1	100	83.5	100	100	86.8	72.7
4	C	Demand Response, PAP Expansion, New PAP, New Pipeline Capacity	2	96.6	85	83.5	95.5	100	70.1
1	Ref	PAP Expansion, New PAP, New Pipeline Capacity	3	96.2	86.5	86	95.5	98.6	46.5
5	C	Energy Efficiency, PAP Expansion, New PAP	4	93.8	86.2	85.8	100	79.1	46.5
3	B	Energy Efficiency, PAP Expansion, New LNG Plant	5	92.8	100	48.6	100	85.9	100
2	A	Energy Efficiency, PAP Expansion, New Pipeline Capacity	6	77.7	99.5	36.4	100	34.2	46.5

Table 3: Portfolio Financial Ranking

Portfolio	Pathway	30-year Enterprise Revenue Requirement ($B)	Average Annual Revenue Requirement ($B)	30-year Gas Revenue ($B)
1	Ref	$35.72	$1.191	$5.74
2	A	$35.78	$1.193	$5.79
3	B	$35.74	$1.191	$5.76
4	C	$35.71	$1.190	$5.73
5	C	$35.72	$1.19	$5.73
6	C	$35.71	$1.19	$5.73

The public process was a critical component needed to incorporate the voice of the Springs Utilities customers into a portfolio recommendation. The various information that was considered and the stakeholder groups referenced in the development of the portfolio recommendation are highlighted in Figure GS4.

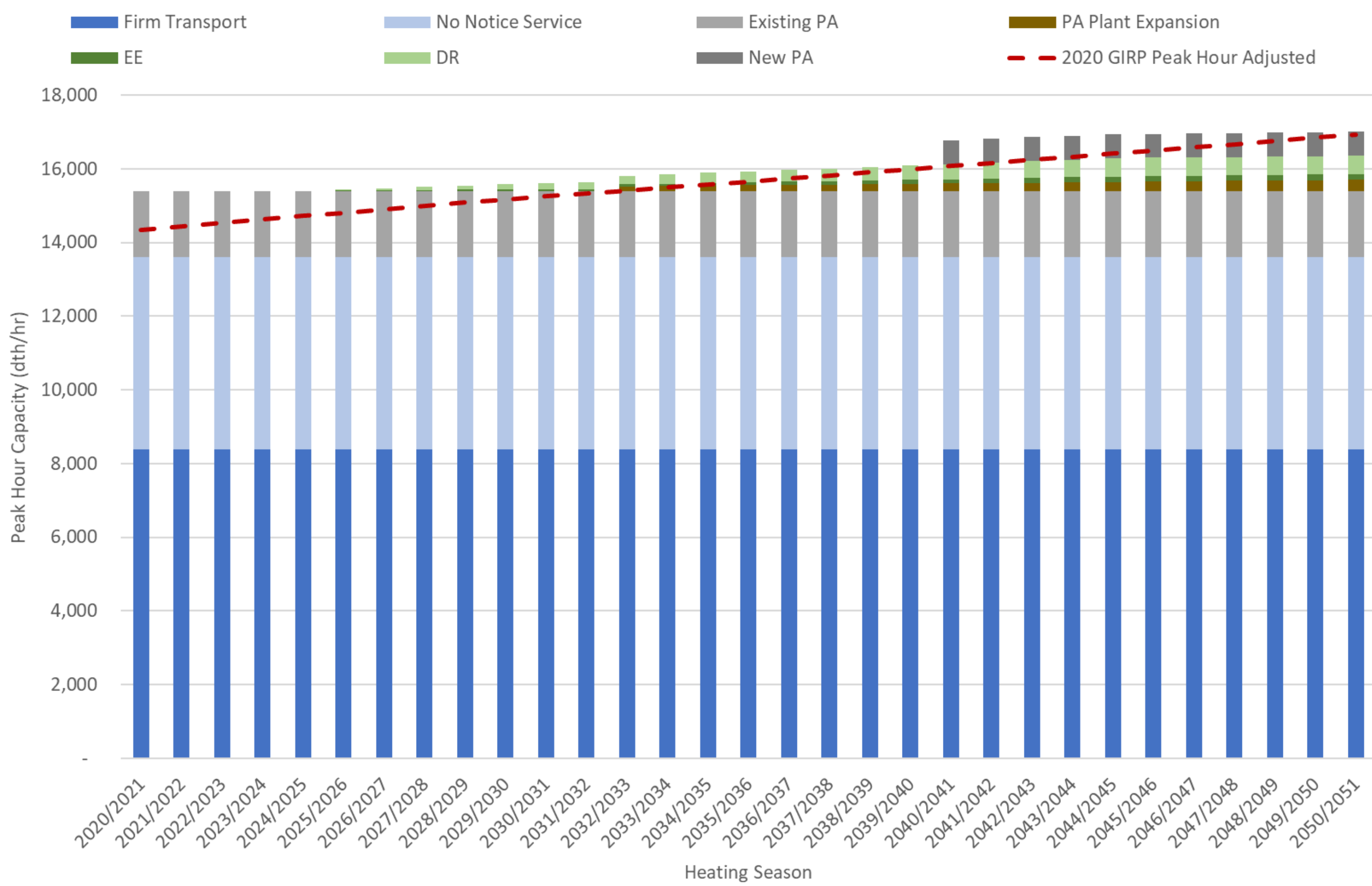
Figure GS4: Portfolio Recommendation Process



Approved Portfolio

After careful consideration of all results, Springs Utilities recommended Portfolio 6 as a path of action to the Utilities Board, which was subsequently approved on June 26, 2020. Portfolio 6 provides an aggressive expansion in demand-side programs. The portfolio includes 500 dth/hr demand response and 150 dth/hr energy efficiency programs, a 300dth/hr expansion of the existing PAP facility in the early 2030s and the addition of a new 650 dth/hr PAP facility by 2040. These resources will be added to the existing base peak load of 15,398 dth/hr.The inclusion of DR and EE programs in this portfolio aligns with Colorado state goals to reduce GHG emissions and defers the construction of a new PAP facility as compared to Portfolio 1. Figure GS5 shows the forecasted peak-hour demand against the natural gas supply for portfolio 6.

Figure GS5: Portfolio 6 2020-2050 Natural Gas Supply



Implementation of Portfolio 6

Actions to be developed further for implementation within this GIRP cycle based on GIRP Portfolio 6 include:

1. Planning to expand capacity of the existing Propane Air Plant to provide an additional 300 Dth/hr of supply capacity as early as year 2032.

2. Feasibility analysis and planning for construction of an additional Propane Air Plant to provide 650 Dth/hour (15,000 Dth/day) of capacity at a new location near the Drennan Gate Station as early as year 2034.

3. Initiation of new Demand-side Management programs to create sustainable reductions in natural gas demand.

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Acknowledgements

Colorado Springs Utilities would like to thank the following team for their collaborative contributions to the Integrated Electric Resources Plan and the Integrated Gas Resource plan. Their technical expertise and professional insight were invaluable in developing and implementing the complex computational approaches used in the EIRP & GIRP.

City Legal Team
Corporate Communication Team
Electric Operations Team
Energy Planning Team
Energy Services Division Team
Environmental Services Team
Finance Services Team
Fuels and Purchase Power Team
Gas Operations Team
Government Affairs Team
Project Management Team
Public Affairs Team

Colorado Springs Utilities would also like to thank members of the EIRP & GIRP Utilities Policy Advisory Committee (UPAC) for their time and dedication to our community. The members spent a great deal of time over the course one and half years learning the details of our Electric and Gas systems and the future challenges our community will experience. They engaged in thoughtful discussion and provided valuable insight and input into the planning process. The UPAC members are:

Chair - Rex Adams
Vice Chair - Scott Harvey
Rich Kramer
Larry Barrett
Balu Bhayani
Gary Burghart
James Colvin
Hilary Dussing

1.0 COMPANY OVERVIEW

1.1 INTRODUCTION

The City of Colorado Springs, Colorado is a home rule municipal corporation with a 2020 population of approximately 486,000, located in the south-central Front Range of Colorado. The economy of the City, and the surrounding area, is based substantially on employment attributable to service industries, retail business, construction industries, education, military installations, the high technology industry, and tourism.

Colorado Springs Utilities ("Springs Utilities") was created by the home rule charter of the City ("Charter") and consists of a water system ("Water System"), an electric light and power system ("Electric System"), a gas system ("Gas System"), a wastewater system ("Wastewater System"), a streetlight system ("Streetlight System"), and other systems designed in accordance with the Charter. The collective combination of Springs Utilities subsidiary systems ("System") is wholly owned by the City and constitutes as an enterprise under certain Colorado Constitution and Charter provisions. Springs Utilities operates primarily through several organizational units responsible for planning, financing, constructing, operating, and customer service associated with the delivery of electric, gas, water, wastewater, and streetlight services.

The service areas for the System includes the City of Colorado Springs, Manitou Springs, and many of the suburban residential areas surrounding the City. The military installations of Fort Carson Army Base ("Fort Carson"), Peterson Air Force Base ("Peterson") and the United States Air Force Academy ("Academy") receive water, electric service, gas supply, and gas distribution services from the System. In addition, Peterson receives wastewater treatment service from the System.

1.2 NATURAL GAS SERVICE

Springs Utilities operates a local distribution system supplying natural gas to approximately 209,000 customers (year end 2019) within a service area of approximately 500 square miles. A map of the Gas System's service area is included in Figure 1-1 below. A total of approximately 25.14 billion standard cubic feet ("bscf" or "bcf") (14.73 pound per square inch absolute or "psia") of natural gas were delivered to customers in 2019 via 2,611 miles of natural gas mains and 169,582 service lines. The Gas System's customer base continues to grow at approximately the same rate as population growth in the greater Colorado Springs area, and the current customer growth rate is forecasted to be 2.0 percent for 2020. Natural gas continues to be the preferred fuel for residential and commercial customers to meet their space heating and water heating requirements. Approximately seven percent of residences and businesses within the Gas System's service area are not natural gas customers. Table 1-1 includes customer and system statistics for 2019. Note 2019 was a relatively mild weather year and not indicative of extreme weather events.

Table 1-1: 2019 Service Area Statistics

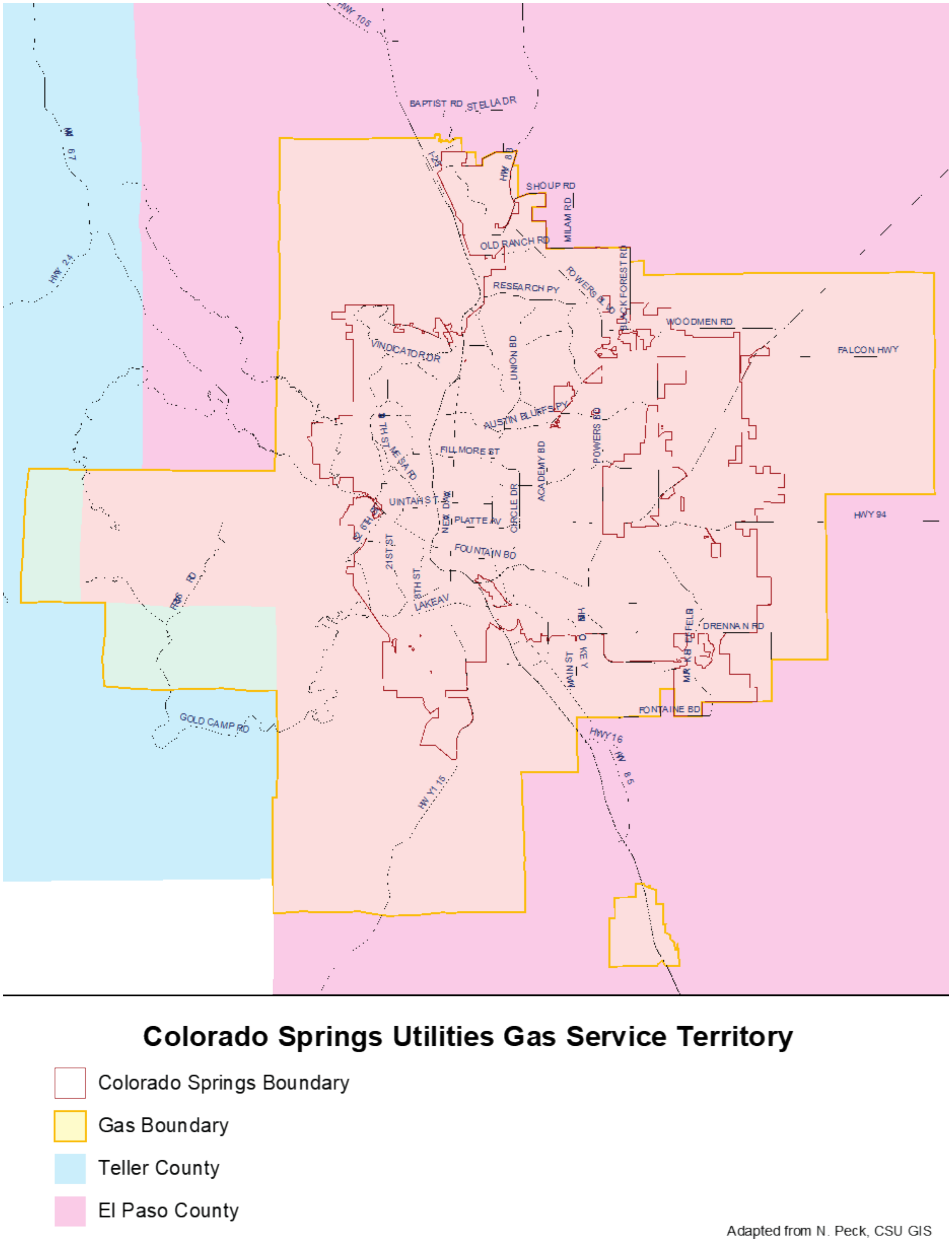
Number of Customers	209,000
Miles of Gas Distribution Lines	2,611 miles
Peak-Day Demand	203,995 mcf @ 14.73 psia
Peak-Hour Demand	11,376 mcf @ 14.73 psia
Annual Demand	25.14 bcf @ 14.73 psia

Springs Utilities purchases natural gas under contracts with a diverse set of gas suppliers including nationwide marketing companies as well as national and regional production companies. Colorado Interstate Gas Company ("CIG"), an interstate gas pipeline owned by Kinder Morgan Corporation ("KM"), transports purchased natural gas from suppliers to the Gas System's distribution facilities. Transportation of natural gas via CIG is subject to various firm, and "no notice" transportation agreements. The Gas System supplements purchased natural gas with a peak-shaving propane-air plant along with contracts for storage services. One of which is the Young Storage Field, with Springs Utilities holding 5 percent of its reservoir and delivery capacity.

The City of Colorado Springs is located within the Front Range natural gas supply region and has access to an abundance of supply in the region. Most of the natural gas produced in the Front Range region is exported since the regional supply far exceeds regional demand. Denver Julesburg ("DJ") is one of the most rapidly growing production basins in the Rockies. An additional benefit to the colocation of natural gas production to the Gas System is a historically lower cost of natural gas relative to most of the United States.

The Gas Integrated Resource Plan ("GIRP") has identified the need for a modest amount of additional peak shaving capacity in the 2030 timeframe. Over the long-term, normal City growth may require additional delivery assets to meet customer requirements. Several options are available for expansion of the existing delivery portfolio, and the most cost-effective solutions are regularly evaluated. Springs Utilities currently has long-term gas supply contracts and has never encountered a problem obtaining sufficient supplies in the past 40 years, nor are any problems anticipated for the future.

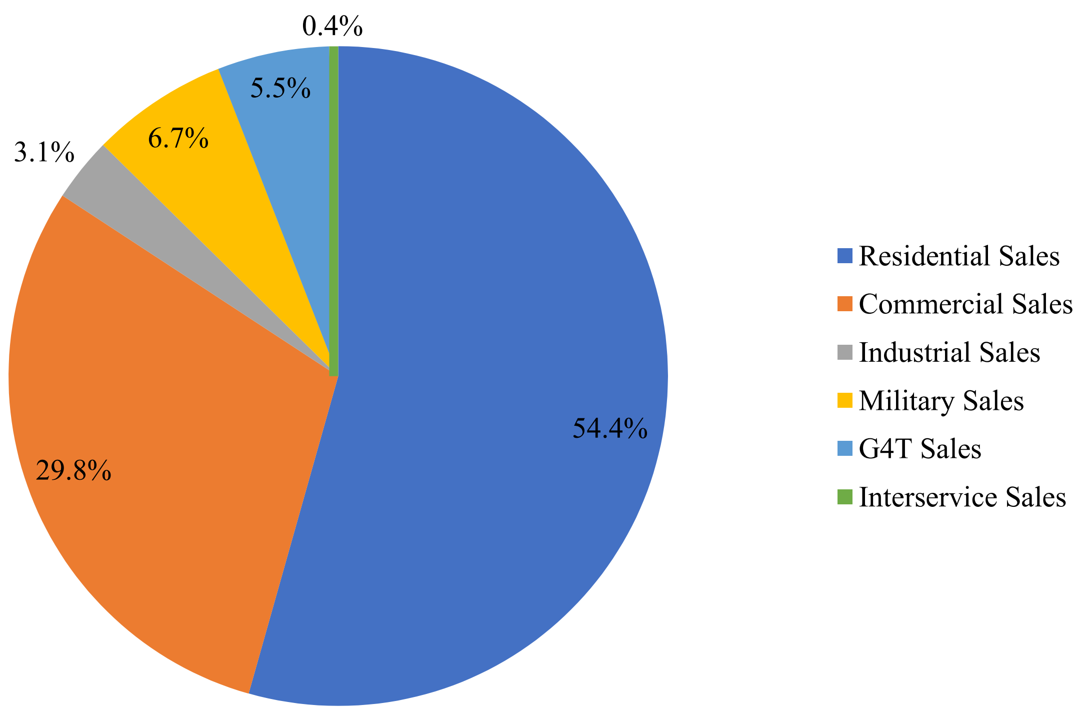
Figure 1-1: Springs Utilities Gas Service Territory



1.2.1 Natural Gas Customers

Springs Utilities provides natural gas service to multiple customer classes: residential, commercial, industrial, and contract (military and utility-owned generation). In addition, Springs Utilities provides transportation service to large customers who purchase their own natural gas supply for their facilities. The customers that procure their natural gas are referred to by their rate class of G4T. Figure 1-2 illustrates the breakdown of natural gas usage by rate class for 2019. Annually, over half of the natural gas consumed in the Colorado Springs area is for residential use. In 2019, the ten largest customers, ranked by sales volume in thousand standard cubic feet ("Mscf"), represented 3,440,808 Mscf or 12.1 percent of total sales (excluding interdepartmental and miscellaneous sales). The top ten customers accounted for $15,886,791 or 8.4 percent of total revenues during that period (excluding interdepartmental and miscellaneous sales).

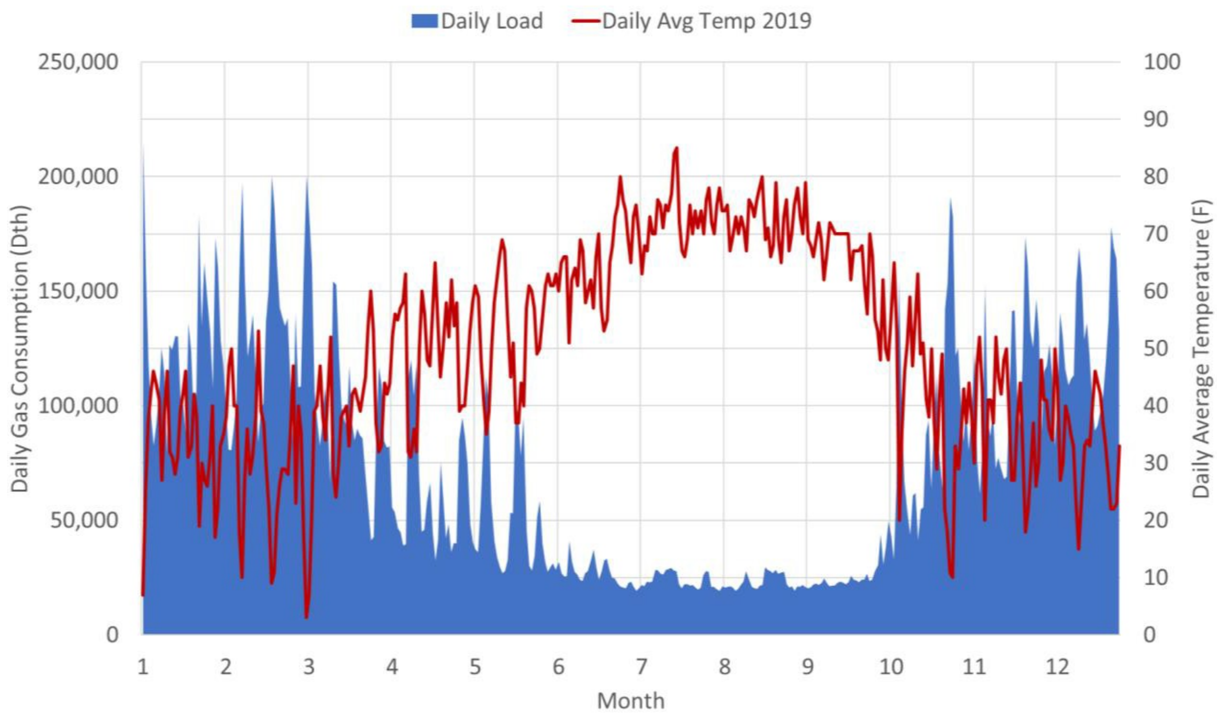
Figure 1-2: 2019 Actual Natural Gas Throughput by Rate Class



1.2.2 Natural Gas Consumption Patterns

Natural gas demand is seasonal, driven by temperature-sensitive space heating loads, particularly for residential and commercial customers. Industrial demand, which typically is not weather sensitive, has minimal seasonal variations in demand. Figure 1-3 includes the total system daily natural gas consumption (load) along with the daily average temperature for 2019. There is a clear inverse relationship between temperature and natural gas consumption, with higher natural gas consumption correlating with colder temperatures.

Figure 1-3: 2019 Daily Natural Gas Usage versus Temperature



1.2.3 Current Natural Gas Rates

Table 1-2 includes the current natural gas rates as they relate to residential and commercial services provided by the Gas System. Springs Utilities levies a Gas Cost Adjustment ("GCA") to cover the cost of procuring natural gas from its suppliers. The GCA considers the forecasted cost of natural gas and is subject to revision as often as monthly, depending on market volatility.

Table 1-2: Current Gas Rates

Gas Rates (Effective February 1, 2021)		
Residential Service - Bills are the sum of:		
Access and Facilities Charges	Per Day	$0.3930
Access and Facilities Charges	Per 100 cubic feet	$0.1681
Gas Cost Adjustment (GCA)	Per 100 cubic feet	$0.1812
Gas Capacity Charge (GCC)	Per 100 cubic feet	$0.0778
Commercial Service - Bills are the sum of:		
Access and Facilities Charges	Per Day	$0.7860
Access and Facilities Charges	Per 100 cubic feet	$0.1650
Gas Cost Adjustment (GCA)	Per 100 cubic feet	$0.1812
Gas Capacity Charge (GCC)	Per 100 cubic feet	$0.0737

1.3 STUDY GOALS AND OBJECTIVES

Springs Utilities effort to manage the development of the current GIRP began in November 2017 with the Gas Peak Management Project. The GIRP effort thoroughly vetted the processes and plans for each functional area, such as Demand Forecasting, Distribution Planning, Supply Side Resources, and Demand-Side Management. The purpose of the GIRP is to ensure customers are provided with long-term safe, reliable, and cost-effective natural gas service. The GIRP evaluates, identifies, and plans for the acquisition or capital investment of existing and future resources to meet peak-day and peak-hour supply and delivery requirements over a 30-year planning horizon. Based on potential resources identified, detailed studies were performed to choose alternatives best aligned with Springs Utilities goals while meeting the demand forecast.

The finalized GIRP will be reviewed annually, considering the triggers below, to ensure immediate actions are identified as determined by the GIRP objectives:

- 5 percent increase in forecasted demand
- New or altered regulatory requirements
- Unplanned changes in availability of distribution or upstream gas assets
- Major regional or operational issues

The comprehensive annual review will continue to ensure that Springs Utilities customers are provided with a safe, reliable, and cost-effective supply of natural gas for years to come.

2.0 PLANNING ENVIRONMENT

2.1 NATURAL GAS SYSTEM OVERVIEW

The U.S. natural gas system is complex and dynamic. New supplies are found in areas with little infrastructure and excess infrastructure exists in other areas where production is in decline. Meanwhile, demographic, and regulatory changes shape trends in natural gas consumption. This chapter looks at the business and physical infrastructure that gets natural gas from production at the wellhead to the consumer, discusses the system used by Springs Utilities, and describes Springs Utilities customer demographics.

The gas industry's physical infrastructure is generally segmented into three areas: production and processing, transmission, and distribution. It is rare for any business in the natural gas industry to be involved in all aspects of the natural gas physical infrastructure. Although there are many kinds of business organizations operating in the natural gas industry, the industry business structure is likewise generally segmented into exploration/production/processing, transmission, and distribution. Springs Utilities operates in the distribution segment. The U.S. Department of Transportation (DOT) Code of Federal Regulations (CFR), federal environmental regulations, and other industry codes adopted by local jurisdictions regulate all industry segments, primarily for safety.

2.1.1 Natural Gas Exploration, Production and Processing

At the beginning of the natural gas system are companies involved in the exploration and production of raw natural gas. Exploration companies find the gas beneath the earth's surface in various types of formations. Production companies remove the gas from the ground.

From the wellhead, the gas is gathered in small diameter pipelines that carry it to processing plants. The processing plants separate the raw natural gas from liquids such as ethane, propane, butane, and higher hydrocarbons, and from other contaminates such as water, carbon dioxide (CO_2) and sulfur compounds. The propane and other higher hydrocarbons are separated into individual components and sent to their respective liquid markets. What remains is "dry" natural gas – pipeline quality methane and ethane suitable for commercial and residential use.

The core business model of exploration and production companies is to develop gas supplies, and to process that gas to pipeline quality specifications for sale to marketers, local distribution companies, and industrial end-users.

Exploration, production, and gas marketing companies are predominantly investor-owned and operate on a free-market basis, with wholesale natural gas prices not regulated. The operations of these companies, however, must meet regulatory requirements for safety and environmental protection which are set by state oil and gas organizations, along with Federal environmental regulations and local jurisdictional requirements.

2.1.2 Natural Gas Transmission

From the processing plant, the dry natural gas is compressed and enters large diameter interstate and intrastate pipelines that are owned and operated by transmission – or pipeline – companies. In the transmission pipelines, the gas combines with other similar natural gas streams and is transported under high pressure to and from storage fields and to distribution gate stations. As the gas moves through this transmission system, its pressure falls, so the gas must be periodically recompressed at various "compressor stations" along the way. The compressor stations are also used to help balance daily supply and demand issues by increasing the pressure beyond what is required and packing extra gas into the system for later use in a technique known as line pack.

Underground storage facilities, consisting of natural or man-made formations into which natural gas can be injected and withdrawn, are often located at strategic points along the pipeline where this inventory of gas acts as a buffer in the transmission system, and helps balance supply and demand requirements.

Transmission businesses typically own and operate interstate/intrastate pipelines, compressor stations, storage fields, and in some cases peak shaving facilities – low-inventory, high-output facilities that provide supplemental gas at times of short duration peaks in demand.

The core business model of gas transmission companies is to receive gas volumes into their pipeline system for delivery to other pipelines, marketers, and end-use industrial customers. Transmission companies operate as a "common carrier," making their pipelines available to any supplier, marketer, or other authorized organization.

Interstate pipeline rates and operating practices are regulated by the Federal Energy Regulatory Commission (FERC), and by law operate under open access requirements. Rate structures and rates-of-return on investment are regulated by FERC in public rate cases.

Transmission companies are typically owned and operated by investor-owned companies. Interstate pipeline companies may own and operate marketing organizations (referred to as marketing affiliates) but must operate the marketing affiliate separate and distinct from the pipeline business and cannot share market and supply information that is not publicly available.

2.1.3 Natural Gas Distribution

The transmission system ultimately delivers the gas to local distribution companies (LDC), who in turn deliver the gas to homes, businesses, and other natural gas consumers within a defined service territory.

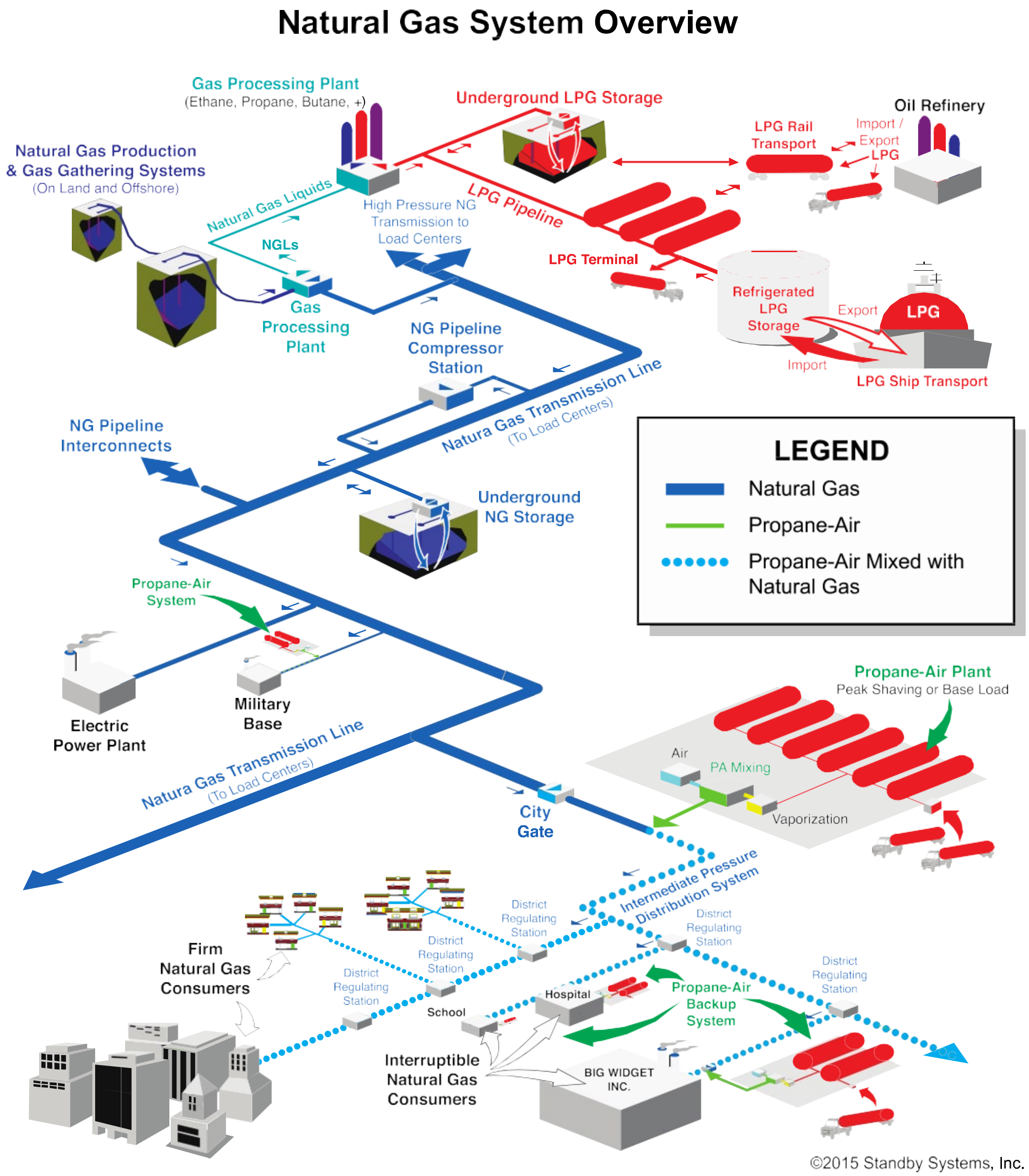
When the gas reaches a load center, the local distribution company takes custody of the gas that they have purchased. The delivery point is known as a city gate, and the piping after the city gate is referred to as distribution piping. At this point, the gas is reduced in pressure, and its flow and energy content measured. The gas is then distributed via smaller diameter pipeline systems to the end-use customers.

Peak shaving facilities help local distribution companies manage periods of high demand. Two common types of peak shaving are liquefied natural gas (LNG) and propane-air (propane mixed with air). In both cases, the gas is stored in liquid form. When needed to meet extra demand levels, the liquid is vaporized back into a gas and is injected into the distribution system to supplement the gas supply. Before injection, the propane undergoes the additional step of being mixed with air.

Springs Utilities is a local distribution company (LDC). The storage fields and peak shaving plants provide operating flexibility for meeting dynamic and extreme load demands, as well as for optimizing the cost benefit of infrastructure investments. Except for peak shaving facilities, the various gas systems of the LDC operate on a continuous basis to meet customer needs, and all systems are designed and operated to meet widely varying load demands driven by weather conditions, industrial needs, and consumer needs.

LDCs own and operate the distribution pipelines – and in some cases intrastate transmission pipelines, storage facilities and peak shaving facilities. The core business model of a local distribution company is to provide safe, reliable, and cost-effective natural gas service to their customer base. LDCs operate in certificated service territories usually determined by state government regulatory agencies. They are owned and operated by investor-owned companies, municipalities, or utility districts created under state, county or other governmental charters. Investor-owned and government-chartered LDC’s serving geographic areas generally operate under franchise agreements with governmental entities (states, cities, towns, municipalities). Rates and service levels are regulated by public utility commissions (PUC), chartered commissions, city councils, or other regulatory bodies.

Figure 2-1: Natural Gas System Overview



Typical natural gas infrastructure. The top of the figure shows natural gas production and processing, where undesired compounds are removed from the gas, and where the gas is purified to acceptable and usable grade. From there, the gas enters the transmission pipeline. The lower portion of this figure shows the roles performed by the local distribution company, as it delivers gas to customers such as residential and industrial consumers.

2.1.4 Springs Utilities Gas System

As a local distribution company, Springs Utilities acquires natural gas through various suppliers and has multiple contracts with Colorado Interstate Gas (CIG), a transmission pipeline company, to transport those supplies to five city gate stations for the Springs Utilities service territory. Springs Utilities also contracts service from an underground natural gas storage reservoir to help balance supply with gas demand. Additionally, the utility owns a propane-air system, which is used to supplement gas supply during extreme peak use periods.

One aspect of the gas industry that is unique to the Front Range of the Rocky Mountain region is gas quality management. Elevation impacts the safety performance of gas appliances, and this is especially true for the continuous operation of older appliances still in use. As a result, the heating content of the gas supplied to homes and businesses on Springs Utilities distribution system has to be managed by injecting air into the gas stream to facilitate proper combustion in all end use appliances. Colorado Interstate Gas (CIG) provides that service to Springs Utilities by operating air injection (air-blending) facilities on their interstate pipeline system.

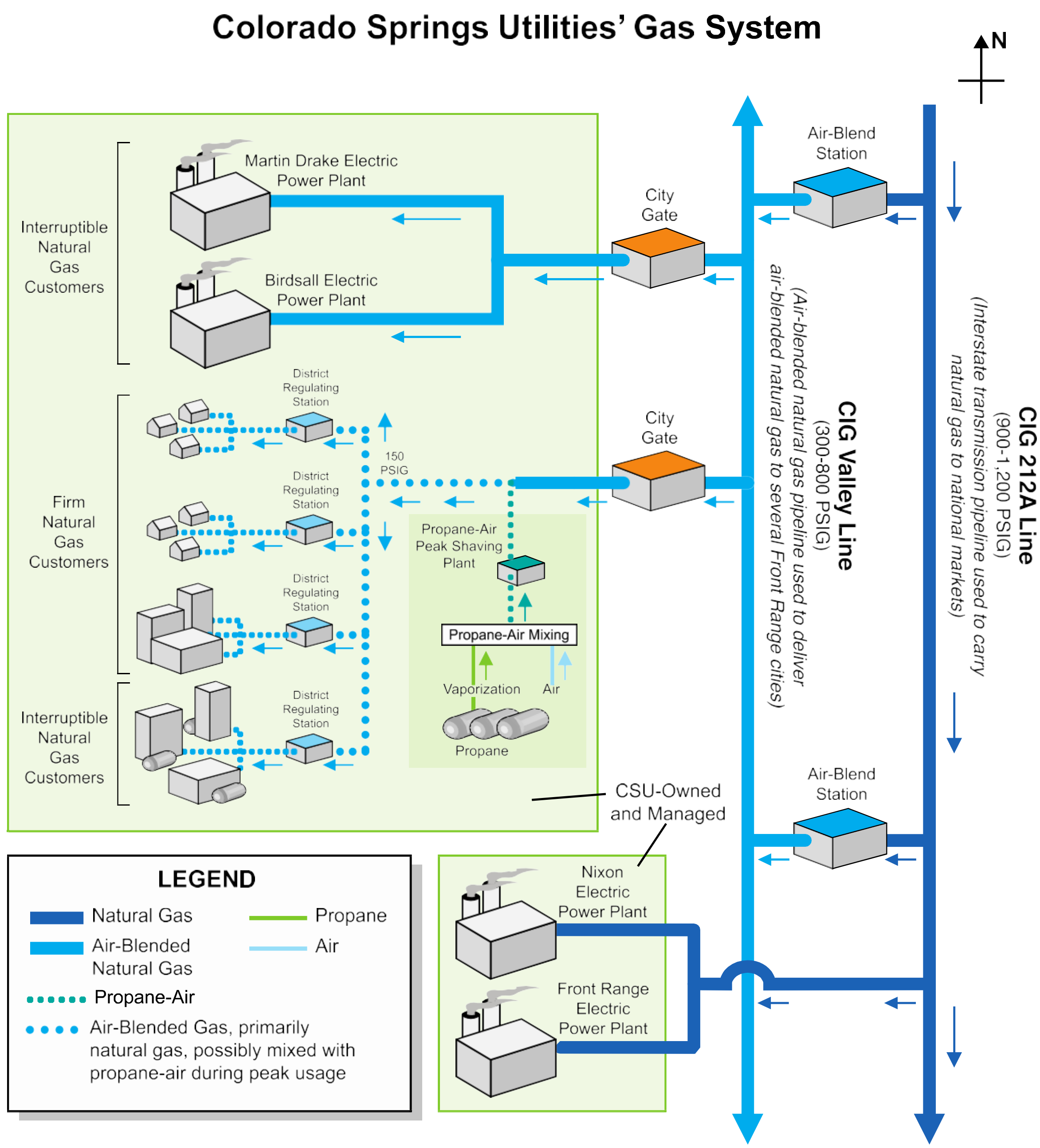
The air-blended gas flows in a separate pipeline that generally runs parallel to the non-air injected interstate transmission line and serves multiple high elevation communities including Colorado Springs. CIG is responsible for this air-blended pipeline as well as for the operation of the required air injection stations.

Air blending is not inexpensive and therefore should not be applied more than what is needed to ensure safety and minimal environmental impact. Regional utilities have conducted and continue to conduct scientific research into the need for, and appropriate levels of, air blending. Springs Utilities will continue to monitor this issue as time goes by to ensure safe and cost-effective solutions.

Colorado Springs' five city gate stations serve as delivery points for the air-blended gas to enter Springs Utilities gas distribution system at a pressure of 145 pounds per square in gauge ("psig") (system maximum allowable operating pressure (MAOP) is 150 psig). Distribution lines move the gas from the gate stations, located on the eastern side of the service territory along Marksheffel Rd, to the western borders of the city. Along the way, the pressure is further reduced at district regulating stations that maintain "street" gas pressure in various areas in its certificated service territory.

Finally, for managing peak natural gas demands, Springs Utilities uses its propane-air peak shaving plant. Propane-air plants store propane in tanks at ambient temperature. During periods of high demand for natural gas, the propane is removed from the tanks, vaporized to a gaseous state and blended with air to produce a propane-air mixture that is compatible with the flowing natural gas. Adding propane-air at times of high demand is a common way that utilities manage natural gas demand. The propane-air plant in Colorado Springs is located adjacent the North city gate station.

Figure 2-2: Springs Utilities Gas System

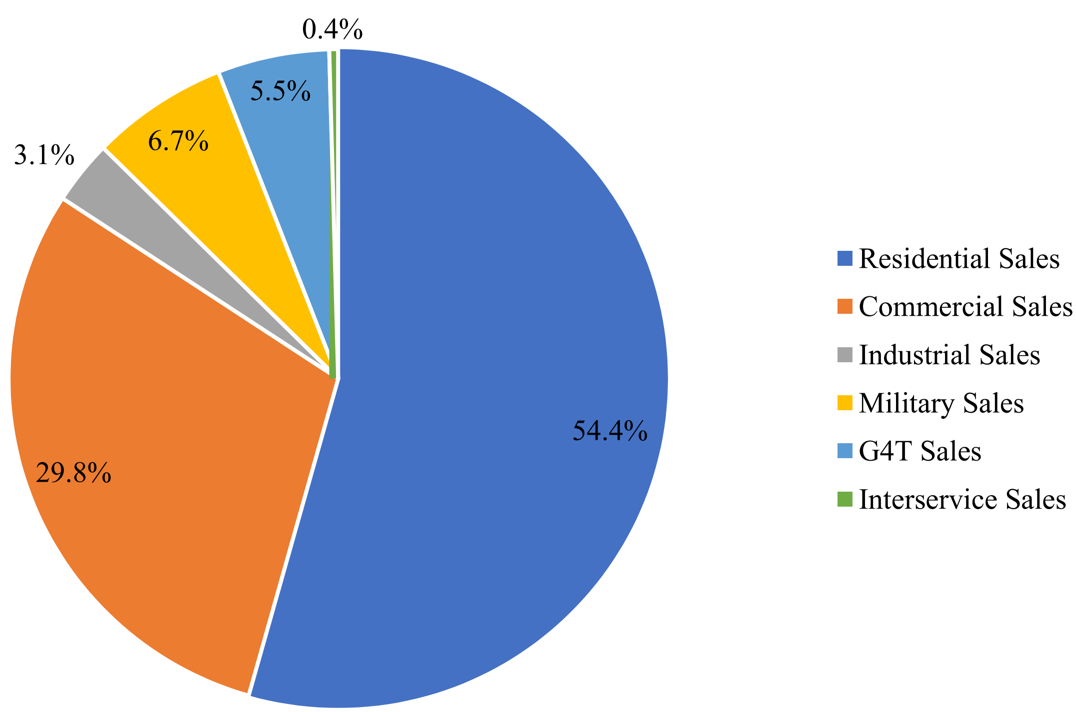


Another look at Springs Utilities distribution system. The CIG Valley Line delivers air-blended gas, which serves the unique need of high elevation areas. For peak shaving, or managing extreme load demand, Springs Utilities supplements the gas supply using a propane-air plant. Additionally. Springs Utilities has several interruptible customers, such as power plants, institutional and industrial customers.

2.1.5 Springs Utilities Customers

Springs Utilities supplies natural gas to over 209,000 customers (year end 2019), delivering 25.14 billion standard cubic feet (at 14.73 psia) in 2019. The service includes residential, commercial, industrial, contract, military and electricity generation rate classifications. Additionally, Springs Utilities provides G4T transport service to eligible customers who have contracted for an alternative source of gas supply and have contracted with Springs Utilities to transport such alternative gas through Springs Utilities gas distribution system for the customer's account. Figure 2-3 includes the 2019 natural gas throughput by customer segment. Residential customers represented over 50 percent of natural gas usage on Springs Utilities system.

Figure 2-3: 2019 Natural Gas Throughput by Rate Class



Natural gas demand is seasonal, particularly for residential customers, and is driven by temperature-sensitive heating loads. Industrial demand, which is typically not weather-sensitive, has minimal seasonality. Over half of the natural gas is consumed by residential customers, nearly a third by commercial, and the remaining fifth by military, transport, industrial and interdepartmental (electricity generation). Due to cold winters and the relatively large portion of residential customers, gas demand is significantly higher in winter months.

Springs Utilities also supplies gas to four electric generating plants. Two of the plants Nixon (gas turbines) and Front Range – are located 20 miles south of Colorado Springs and have independent, not-air-blended natural gas transportation under Colorado Interstate Gas mainline transportation contracts. The plants are served directly from the CIG pipeline and are not considered a part of Springs Utilities distribution system.

The other two plants, Birdsall and Martin Drake, are located within Colorado Springs city limits and receive air-blended natural gas services just like any other commercial or residential gas customer on the gas distribution system. The supply to the Birdsall and Martin Drake plants is interruptible, meaning that gas supply to the plants can be curtailed during periods of high usage on the distribution system.

Transmission and distribution pipelines are limited as to how much gas can flow at any one time. Furthermore, utilities or other pipeline users, are only contracted for a specific amount of guaranteed capacity (firm delivery). Interruptible customers are one way for distribution companies, including Springs Utilities, to manage the finite capacity on the pipelines. In addition to the electric power plants, other large commercial and industrial customers also operate under interruptible supply contracts, which offer a lower cost of service in return for switching from gas to an alternative fuel supply during peak demand periods.

For most customers, Springs Utilities is obligated to deliver whatever volume is needed by the customer under firm delivery requirements. In other words, Springs Utilities is required to ensure that gas is always available to these customers. Limitations due to pipeline restrictions are not acceptable and must be balanced with supply resources such as no notice service (storage), peak shaving facilities or contract for additional capacity on the pipeline if capacity is available. Providing reliable natural gas supply to customers is a core business objective of Springs Utilities.

2.2 NATURAL GAS SUPPLY

2.2.1 Supply Basins

2.2.1.1 Rockies Supply

The Rockies supply region encompasses about eight separate supply basins. The major supply basins include the Green River, Wind River, Powder River, Uinta, Piceance, and the Denver-Julesburg (“DJ”) all of which deliver gas directly into CIG. Supply basins in the Front Range cover large geographical areas and contain huge potential and known natural gas reserves. Advanced directional drilling technology has lowered drilling costs, and enhanced recovery methods have elevated the Front Range as one of the primary gas producing regions in the U.S far into the future.

Colorado Springs benefits from close proximity to multiple production basins in the Front Range supply region. Most Front Range natural gas production sites are in Colorado, Utah and Wyoming.

However, less than 20% of the gas produced in the Front Range is consumed by communities in the Front Range. The remaining supplies are exported via interstate gas pipelines outside the region in all directions. Historically, as new natural gas production grows, the abundance of supply in the Front Range exceeds pipeline capacity, constraining supply deliveries to higher priced markets outside the Front Range region. This creates a supply surplus and pushes down local prices. Over time, this cycle has greatly benefited local Front Range communities. However, eventually the depressed local prices make it economically feasible to build additional pipeline transport capacity to move the gas out of the Front Range. The last major pipeline addition in the region transports gas from the DJ Basin to the Cheyenne Hub is called the Cheyenne Connector. indicated below, a majority of gas produced in the Front Range region is delivered to markets outside of the Front Range.

- **Total Front Range Region Natural Gas Production on December 31, 2019:** 7.36 Bcf/day
- **Total Natural Gas Exports from Front Range Region:** 4.59 Bcf/day
- **Implied Production to Local Front Range Markets:** 2.77 Bcf/day

In winter, the local Front Range Markets use approximately 3.0 Bcf/day and as it stands today, there is sufficient pipeline export capacity in all directions so local wholesale natural gas prices are only marginally lower than the national average.

2.2.1.2 Mid-Continent Supplies

The Mid-Continent region includes all of Oklahoma and portions of Texas, Kansas, Nebraska, Arkansas, Missouri and Iowa and the rapidly expanding Permian Basin in New Mexico. The most important gas producing basins are the Anadarko and the Arkoma. The Kansas Hugoton field, in the Anadarko basin near the Colorado Kansas border, is the largest gas field in the United States. Gas produced from the Hugoton Basin can be accessed from the CIG southern system and back hauled into the Front Range.

2.2.2 Transportation

When transporting natural gas via interstate pipelines, customers may choose among a variety of services. One service offered is firm transportation where an agreement is executed between the pipeline and a customer for a certain duration providing service between primary receipt and delivery points. Customers with firm transportation service generally receive priority for their contracted quantity and are among the last customers to be curtailed in the event of pipeline restrictions or constraints. Because Springs Utilities customers expect natural gas to be available during peak demand periods, Springs Utilities generally procures firm transportation for its natural gas supplies. Springs Utilities currently has firm transportation capacity on CIG for transporting natural gas from suppliers to the gas system. The existing contract with CIG is through 2021 and is assumed to be renewed for the duration of the analysis. CIG is currently fully subscribed, and no additional firm capacity is available on the pipeline. Additional firm capacity would have to be temporarily leased from another subscriber with excess capacity or a capacity expansion project would have to be completed.

An alternative to firm transportation is interruptible transportation. Interruptible transportation is generally offered to customers on an as-available basis and can be interrupted on a short notice for a specified number of days or hours during times of peak demand or system emergencies. Customers with interruptible service generally pay lower transportation prices as compared to firm transportation customers. Due to the lack of guaranteed availability during peak demand periods, Springs Utilities does not consider interruptible transportation an option towards meeting firm supply obligations.

2.2.3 Renewable Natural Gas

Renewable natural gas ("RNG") is pipeline-quality gas that is fully interchangeable with conventional natural gas. RNG is essentially biogas (formed from the decomposition of organic matter) that has been processed to meet natural gas purity standards. RNG can be sourced via various methods including capture from landfills, livestock operations, wastewater treatment, and other industrial processes. Additionally, research is being conducted in biochemical processes such as anaerobic digestion and thermochemical processes such as gasification. When conventional natural gas is replaced with RNG, there typically is a net decrease in greenhouse gas ("GHG") emissions. Depending on the feedstock, RNG generally has a lower carbon footprint than conventional natural gas, after accounting for emissions from fuel production, transport, and use. RNG can have an even lower footprint if a project can consider directly reducing methane emissions from organic waste used to produce the RNG. In recent years, regulatory requirements, customer interest, and environmental concerns have increased interest in RNG as a fuel option. Economics of RNG are heavily dependent on the feedstock and should be evaluated on a case-by-case basis.

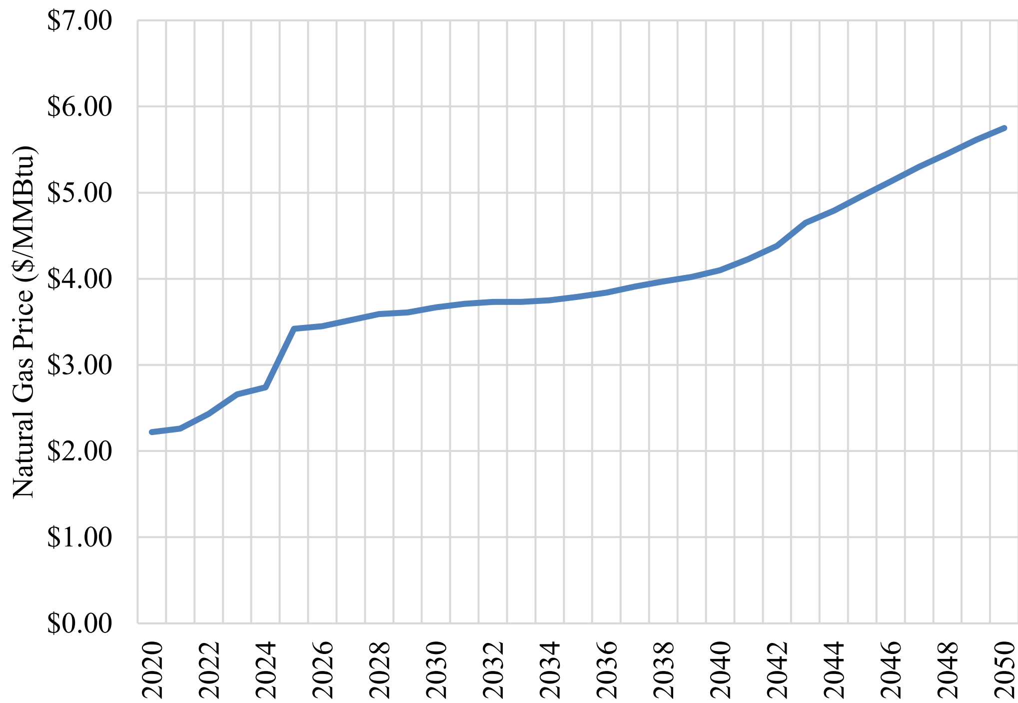
2.2.4 Current and Future Market Conditions

Springs Utilities currently receives its natural gas supply via CIG. Pipeline disruptions are rare, but in the event flows are interrupted, Springs Utilities could have issues receiving natural gas. Additionally, the surplus of natural gas produced in the Rocky Mountain Basin provides ample access to natural gas produced relatively near Springs Utilities system. If production substantially decreases in the Rocky Mountain Basin, natural gas will to be sourced from external regions, thus increasing reliance on long-distance transportation via pipeline. Continued economic growth in the Front Range region could additionally place additional constraints on pipeline transportation availability.

2.2.5 Gas Price Forecast

The forecast of natural gas prices used in the GIRP are consistent with the forecast used in the Electric Integrated Resource Plan. The forecast was sourced from ABB and provided through 2043. After 2043, the 5-year average growth rate was applied to project prices through 2050. The baseline natural gas forecast is included below in Figure 2-4.

Figure 2-4: Natural Gas Forecast



2.3 ENVIRONMENTAL POLICY

2.3.1 Current Legislation

The legislative and regulatory environment has changed significantly since the 2015 GIRP, and the Colorado Legislature has recently passed several bills aimed at reducing Colorado's statewide greenhouse gas ("GHG") emissions. State bills that may potentially impact Springs Utilities gas business include:

House Bill 19-1261: Climate Action Plan to Reduce Pollution: Establishes statewide GHG pollution reduction goals relative to 2005 emission levels. The reduction goals are a 26 percent reduction by 2025, 50 percent reduction by 2030, and 90 percent reduction by 2050.

Senate Bill 19-096: Collect Long-term Climate Change Data: Requires the Air Quality Control Commission ("AQCC") to collect and report on GHG pollution, forecast future emissions, and adopt a statewide GHG reporting rule by June 1, 2020. The bill additionally states the AQCC shall begin producing rules to address emissions by July 1, 2020.

Senate Bill 19-181: Protect Public Welfare Oil and Gas Operations: Prioritizes the protection of public safety, health, welfare, and the environment in the regulation of the oil and gas industry by modifying the oil and gas statues and by clarifying, reinforcing, or establishing various aspects of local governments' regulatory authority over the surface impacts of oil and gas development.

House Bill 19-1231: New Appliance and Water Efficiency Standards: Updates and adopts energy efficiency and water efficiency standards for certain appliances and plumbing fixtures

House Bill 19-1260: Building Energy Code: Requires cities or counties to adopt one of the three most recent energy conservation codes when they update building codes.

Senate Bill 20-124: Public School Construction Guidelines: Requires schools seeking funds from the state capital assistance fund to consult with the local electric utility on energy efficiency, beneficial electrification, and renewable distributed generation opportunities.

Of the measures passed in recent years, HB19-1261 is the most expansive as it sets GHG emission reduction goals into state law and empowers the Colorado Air Quality Control Commission to adopt the necessary rules needed to achieve legislative targets. Since the goals outlined in HB19-1261 require GHG emission reductions from virtually every sector of the economy, the Polis Administration has developed a "Colorado Greenhouse Gas Pollution Reduction Roadmap." The roadmap identifies goals, methods, and targets to achieve the 2025, 2030, and 2050 GHG emission reduction goals, and will be used as a basis for additional forthcoming legislative and regulatory changes. The GHG Roadmap recommends the following actions:

- Expand energy efficiency investments from natural gas utilities to support building shell improvements
- Set carbon reduction goals, leak reduction targets, and renewable natural gas requirements for natural gas utilities

- Require existing large commercial buildings to track energy use and make progress toward energy and pollution performance standards
- Support adoption of advanced building codes
- Require regulated electric utilities to create programs that support customer adoption of electric heat pumps and other forms of beneficial electrification

The exact impacts on Springs Utilities natural gas business are developing, but anticipated impacts include:

- In Springs Utilities chosen portfolio in the Electric Integrated Resource Plan, coal-fired generation will be retired in the near-term and partially replaced with natural-gas fired generation, likely increasing gas demand during peak weather conditions
- Conversely, there could be reduced retail gas load growth due to beneficial electrification, building shell energy efficiency requirements, and appliance efficiency improvements
- Potential stranding and reduced use of gas distribution assets due to reduced natural gas demand via impacts of beneficial electrification
- Higher cost of Colorado-sourced natural gas due to increased oil and gas well setbacks and GHG emission controls
- Potential rate increases on the KM/CIG system due to loss of natural gas demand, resulting in higher unit costs for the Gas System
- Regulatory costs imposed on hydrocarbon emissions from gas distribution operations

2.3.2 Legislative Initiatives

2.3.2.1 Renewable Natural Gas

Legislation has been proposed in the Colorado State Legislature to mandate a RNG standard for large natural gas utilities. Colorado SB 20-150 proposed specific targets for RNG adoption for large natural gas utilities. The proposed targets included 5% RNG by 2025, 10% RNG by 2030, and 15% by 2035. The proposal made participation optional for municipal gas utilities and therefore Springs Utilities would participate on a voluntary basis. As part of the GIRP, Springs Utilities evaluated the impacts of incorporating RNG into its supply. RNG could offer a way to directly reduce emissions from gas consumptions and will continue to be evaluated in future GIRPs. Should customer interest in RNG grow, Springs Utilities can further explore RNG supply options.

2.3.3 Greenhouse Gases

2.3.3.1 Compressed Natural Gas

Compressed Natural Gas (“CNG”) is natural gas that has been compressed to less than one percent of its volume at standard atmospheric pressure. CNG has been increasingly used as an alternative fuel for vehicles and is estimated to have lifecycle emissions 15 percent lower than gasoline vehicles. CNG systems additionally produce no evaporative emissions and produce fewer particulate emissions than gasoline or diesel fuel. Heavy-duty vehicles have increasingly started to use CNG as their primary fuel. Vehicle fueling infrastructure has expanded in recent years but remains rare compared to gasoline and diesel fueling stations. Springs Utilities will continue to evaluate the potential for CNG applications on its system and the potential for expanding use in heavy-duty vehicles. Expanding the use of CNG in traditional vehicles would be a way Springs Utilities can help customers meet emissions target reductions, while meeting fueling requirements.

2.3.3.2 Energy Efficiency

Multiple laws have been passed in Colorado encouraging and mandating the adoption of energy efficiency measures as part of GHG emission reduction efforts. Specifically, HB 19-1231, HB 19-1260, and SB 20-124 all mandate improvements in energy efficiency to new appliances, building codes, and public-school construction. The demand-side analysis performed in the GIRP is consistent with the goals of these laws and provides potential avenues by which Springs Utilities can help customers meet these regulatory requirements. Additionally, improvements in efficiency are mutually beneficial to customers and Springs Utilities because of reduced natural gas bills and the deferral of additional natural gas supply resources. Springs Utilities can take an active role in promoting energy efficient products and building practices to customers. These measures can also help Springs Utilities and its customers reduce their carbon footprint via more efficient use of energy.

3.0 DEMAND FORECAST

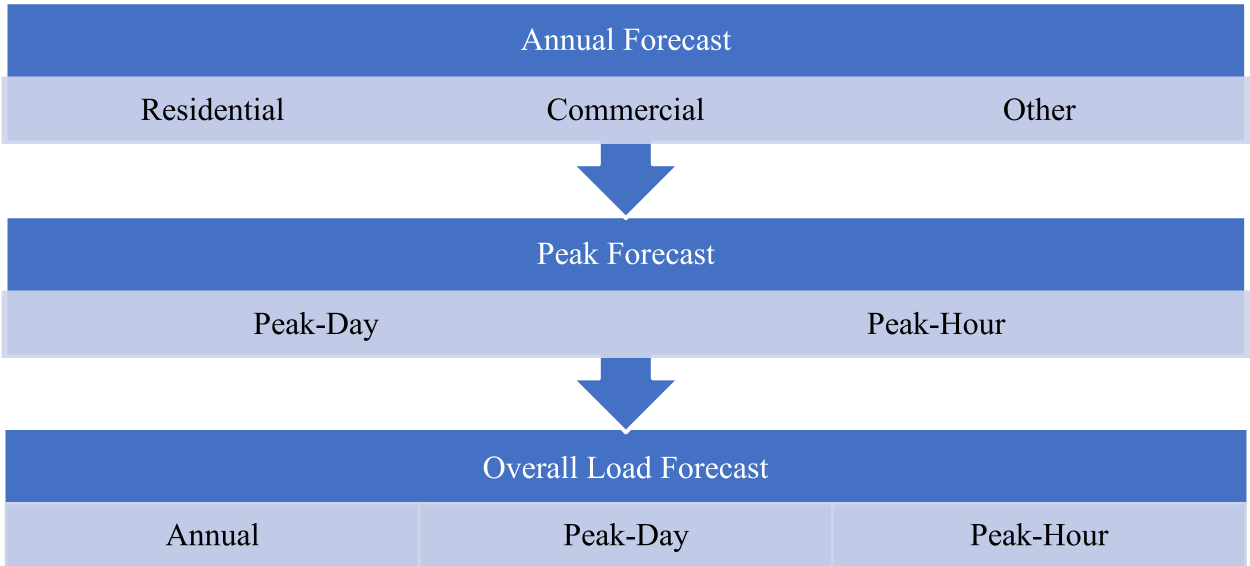
Customers of Springs Utilities rely on natural gas for both residential use and to run their businesses. To ensure that customers receive safe, reliable, and cost-effective natural gas service, Springs Utilities must make timely resource investments to accommodate customer needs. Part of that process involves forecasting anticipated future natural gas demand. The following sections outline methods, assumptions, and results of the process used to produce the long-term demand forecast used in the GIRP. A partnership between the Office of Economic Development ("OED") and Springs Utilities staff resulted in multiple scenarios for forecasted customer growth and natural gas demand. Overall, the base forecast includes a net increase in the number of customers and an increase in the total natural gas demand.

3.1 FORECAST APPROACH

The demand forecast consisted of two major steps, each responsible for developing specific aspects of the overall demand forecast. The first step produces an annual demand forecast, which estimates the growth in total natural gas sales and throughput. The annual forecast provides estimates for volume, revenue, and customer forecasts, which serve as the foundation for the Annual Operating Plan, resource planning, and daily operations. The annual forecast accounts for large scale trends, such as a growing customer base and changes in use-per-customer. These large-scale trends are reflected in the annual sales and load forecast which are based on fifteen-year weather averages. The annual forecast is primarily impacted by large scale factors such as economic outlook, population growth, and changes in appliance efficiencies.

The second step of the forecast determines the peak-day and peak-hour forecasts, which are used to ensure adequate supply of natural gas during peak demand conditions. To ensure system reliability, Springs Utilities plans for a one-in-twenty-five-year cold weather event when developing peak-day and peak-hour demand forecasts. Historical consumption data and multiple linear regression analysis are used to forecast the peak-day and peak-hour demand, which identifies the maximum expected demand on the system during an extreme weather event, when space heating demand is the predominant use on the Gas System. Note certain customers arrange a separate supply of natural gas and contract only for distribution services (rate class G4T). Since Springs Utilities is not responsible for procuring natural gas supply for G4T customers, the G4T usage forecast is only used for CIG transportation and distribution planning. Figure 3-1 contains a general overview of the load forecasting process.

Figure 3-1: Demand Forecast Process



The annual, peak-day, and peak-hour forecasts were then used to evaluate the ability of current resources to meet growing customer demands. The forecast for natural gas usage by all customers is used to evaluate the Gas System's supply, demand, and distribution requirements. The following sections discuss the methods and results of the load forecasting process conducted during the 2020 GIRP.

3.2 PLANNING STANDARDS

In natural gas demand forecasting, average daily temperature along with Heating Degree Days ("HDD") are used as common metrics. HDDs account for heating that is expecting, using 65 degrees Fahrenheit ("°F") as a reference point for when heating begins. It is important to note that HDD do not account for the impacts of wind chill and are based solely on the average daily temperature. Springs Utilities plans for a one-in-twenty-five-year cold weather event when assessing the adequacy of Gas System resources.

The Gas System consumption record occurred on February 1, 2011. On that day, Springs Utilities daily demand set a system record of over 266,925 Dth. Prolonged cold weather and strong winds were the primary factors behind the record system demand. The average temperature was -7°F, corresponding to 72 HDD, and when accounting for the wind, the wind chill was -27°F. Regardless of the frigid weather on February 1, 2011, the conditions were not indicative of a one-in-twenty-five-year weather event.

The lowest daily average temperature occurred on December 21, 1990, with a daily average temperature of -16°F and was considered a one-in-sixty-year occurrence. Analysis of weather data dating back to 1946 indicates a one-in-twenty-five-year occurrence would be an average daily temperature of -13°F.

Therefore, peak-day and peak-hour forecasts were based on a -13°F average daily temperature. Table 3-1 includes the weather conditions used in the peak-day and peak-hour load forecasting process.

Table 3-1: Gas System Peak Planning Criteria

Time Period	Metric Used	Temperature (°F)	Heating Degree Day	Wind Speed (mph)
Daily	24 Hour Average	-13.0	78.0	12.0
Hourly	Minimum Temperature	-20.0	N/A	8.0

3.3 HISTORICAL WEATHER AND DEMAND

Springs Utilities recognizes that natural gas demand is a function of customer baseline usage plus weather-sensitive usage. The goal of the forecast is to predict both the base load and weather-sensitive demand to forecast total natural gas consumption for any given day or hour. Generally, as the outside air temperature decreases, natural gas demand increases due to space heating requirements. In addition to the temperature-sensitive heating demand, industrial customer usage, residential water heaters, gas stoves, gas ovens, and clothes dryers are additional drivers of natural gas demand. These use categories are not impacted by the outside air temperature and represent the baseline level of natural gas demand on the system. Due to the baseline load, natural gas demand remains relatively constant until space heating requires additional natural gas. The estimated baseline load for 2018 was 17,800 dekatherms ("Dth") per day. The correlation between natural gas consumption and temperature is shown in Figure 3-2 below. As temperatures decrease below 65°F, natural gas consumption increases due to space heating requirements. Below 55°F, the relationship between average temperature and natural gas consumption becomes linear, with outside air temperature directly correlating to natural gas consumption.

Figure 3-2: Gas Consumption Versus Temperature

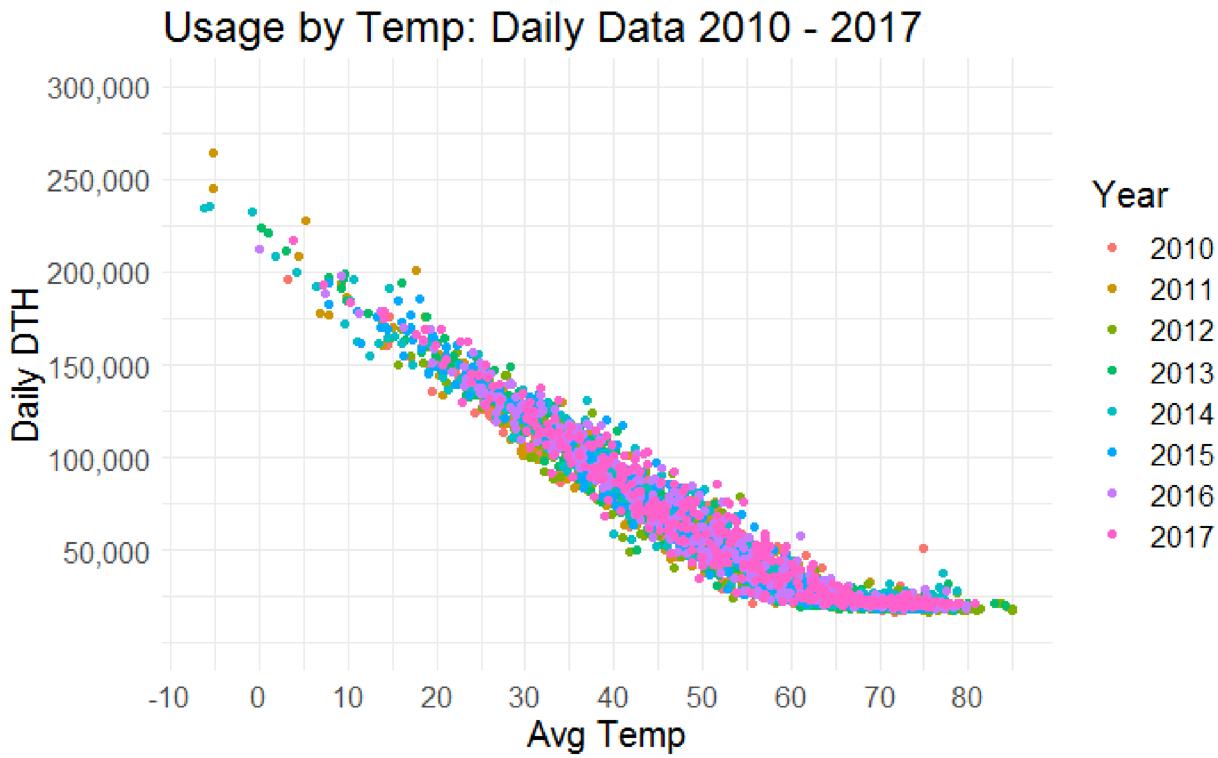


Table 3-2 includes data for historic peak days experienced by Springs Utilities' system. The daily peak consumption occurred on February 1st, 2011, with a daily consumption of 266,925 Dth.

Table 3-2: Historic Gas Day Data

Historic Gas Day Data							
Date	**Daily Load (Dth)**	**Daily Average Temp (°F)**	**Daily Average Wind Chill (°F)**	**Peak Hour Wind Chill (°F)**	**Daily Average Wind Speed (mph)**	**Peak Hour Wind Speed (mph)**	**Peak Hour (Dth/hr)**
2/1/2011	**266,925**	-6.7	-27.3	-35.2	16.0	26.0	12,256
2/2/2011	235,069	-1.7	-12.4	-21.5	10.0	11	12,108
1/31/2011	208,966	6.8	-15.7	-33	21	24	12,194

3.4 ECONOMIC OUTLOOK

An important factor in the load forecast is the economic outlook for the forecast period. Local economic conditions impact the customer behavior of specific rate classes and thus were incorporated into the load forecast. Important economic figures included in the load forecast included local population, employment, and Gross Municipal Product. Table 3-3 includes the 10-year average growth rates for key economic indicators used in the load forecast. A complete listing of the economic variables used in the models and a description of each variable's impact on the forecast can be found in Appendix A.

Table 3-3: Colorado Springs 10-Year Economic Forecast

10-Year Local Outlook	
Economic Parameter	**10-Year Average Growth Rate (%)**
Population Growth	1.30%
Household Size	-0.40%
Real Personal Income	2.40%
Total Employment	1.60%
Total Gross Municipal Product	1.30%

3.5 ANNUAL FORECAST

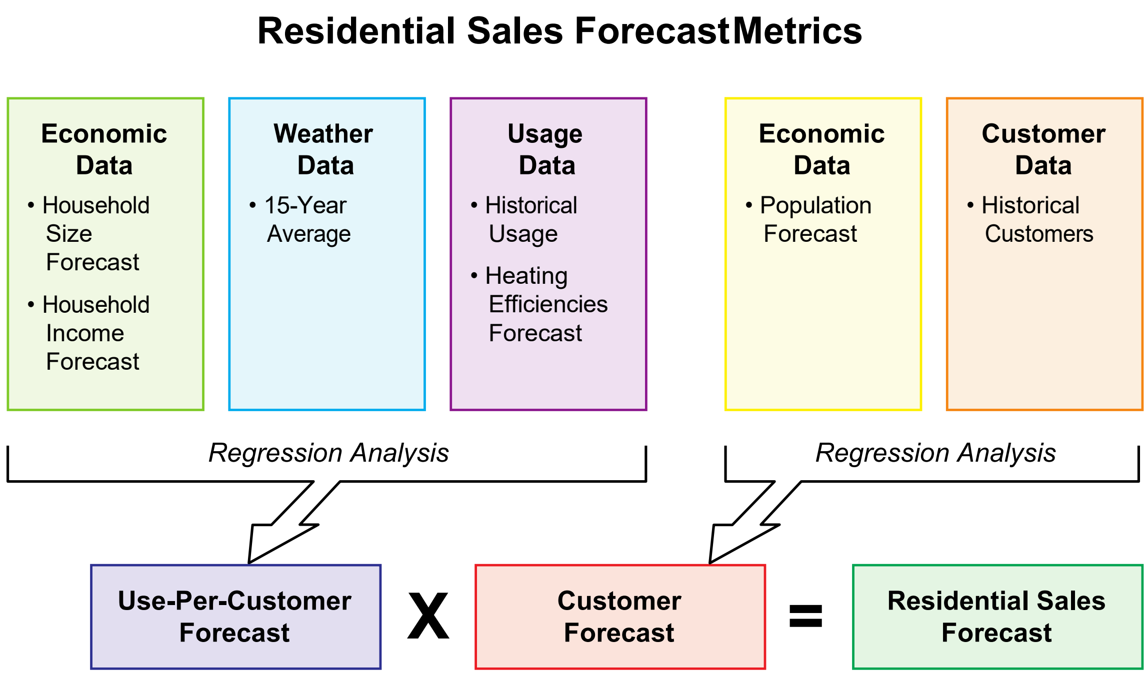
3.5.1 Forecast Methods

The natural gas annual sales and load forecasts were derived from a combination of historical data, econometric models, economic data, political climate, trends, and organizational knowledge. The forecast is broken down by customer group, or rate class, since natural gas consumption in each customer group reacts differently to factors such as economic outlook and weather-related use. The two largest customer groups, residential and commercial customers, are further broken down into customer forecasts and end-use forecasts. Customer forecasts are based on population and employment forecasts. Econometric models depict statistical relationships between historical data and forecasted variables to forecast future outcomes. End-use models (also use-per-customer models) incorporate information, such as appliance efficiency standards and changing population demographics. End-use models are used for the residential rate class as well as the small and large commercial rate classes. The end-use models in combination with the customer forecast create an overall sales forecast for each rate class. Economic data, political climate, trends, and organizational knowledge were used to forecast the remaining rate classes (seasonal commercial, indexed commercial, industrial, military, and G4T customers).

3.5.2 Residential Forecast

Customers in the residential rate class use natural gas primarily for home heating, water heating, and cooking. Residential customers currently account for approximately 89% of the Gas System's customer count and roughly 54% of the natural gas distributed via Springs Utilities gas distribution system. Springs Utilities is responsible for maintaining sufficient supply, distribution, and demand resources for this rate class. Figure 3-3 includes an overview of the factors used to create the residential sales forecast.

Figure 3-3: Residential Sales Forecast Metrics



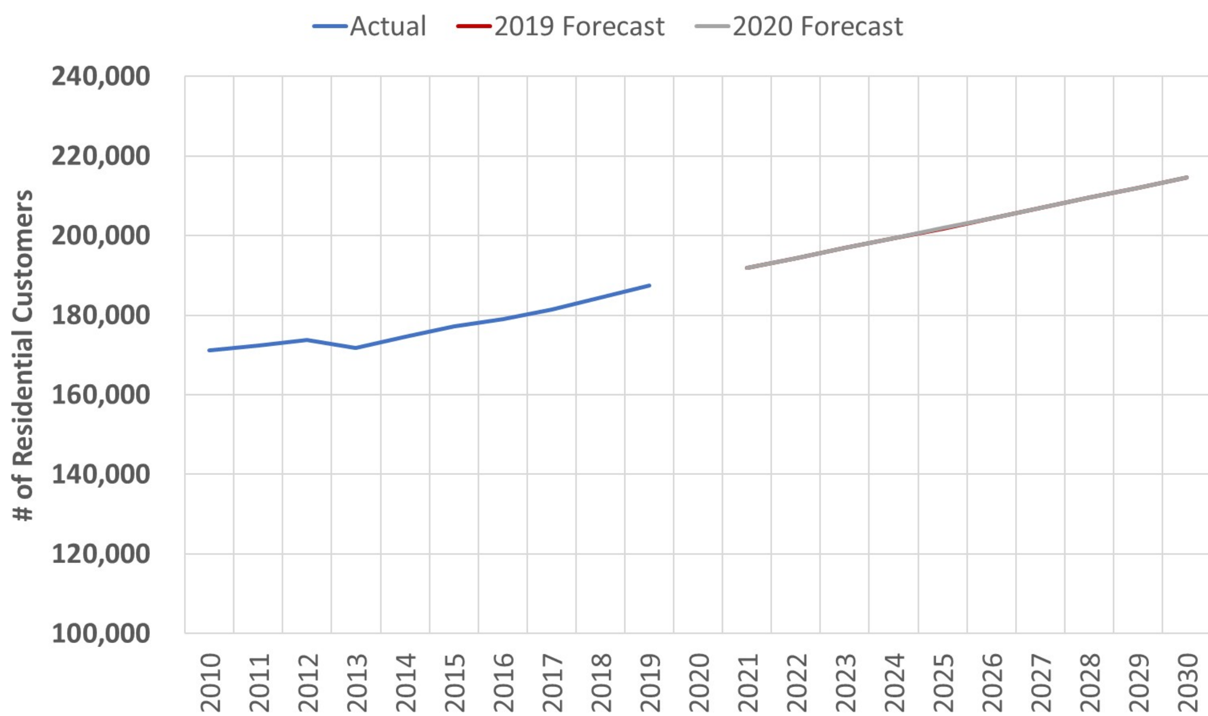
3.5.2.1 Residential Customer Forecast

Based on the forecasted economic outlook, the number of residential natural gas customers is expected to grow over the study period. Population growth is the primary driver behind customer growth, and the number of residential customers is expected to grow at an average rate of 1.3 percent through 2030. Table 3-4 includes an overview of the various growth rates in the forecast along with a comparison to the 2019 forecast. Figure 3-4 includes a chart with the historical number of Residential accounts along with the forecast through 2030.

Table 3-4: Natural Gas Residential Customer Growth Rates

Natural Gas Residential Customer Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	1.3%	1.3%
10-Year Historical	1.0%	1.0%
5- Year Forecast	1.3%	1.3%
10-Year Forecast	1.3%	1.3%

Figure 3-4: Natural Gas Residential Customer Forecast



3.5.2.2 Residential Use-Per-Customer Forecast

One of the main trends impacting residential natural gas sales, which comprises of over half of total sales, is use-per-customer ("UPC"). The two main drivers of use-per-customer are efficiencies of customer's appliances and economic outlook. The load forecast analyzed these trends using regression analysis.

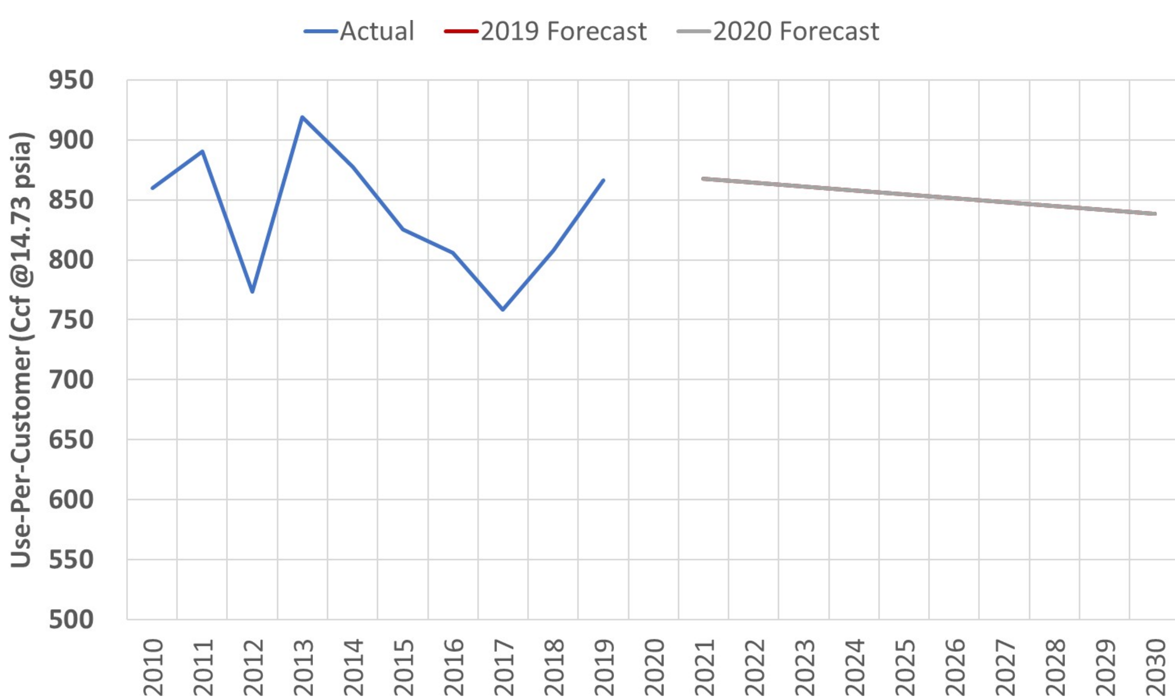
Residential use-per-customer is heavily impacted by appliance efficiency standards, as natural gas-fired furnaces account for most of the residential natural gas usage in the winter. Over the past two decades, improvements in insulation, appliance efficiency, and building design, have resulted in the annual average residential use-per-customer declining by 25 percent. Appliances with improved efficiencies continue to contribute to the overall decline in use-per-customer. However, because historically most furnaces were at a higher efficiency level than required by efficiency standards, the rate at which use-per-customer is declining is expected to slow.

The primary economic data used in residential forecasts is household size and income. Household size is expected to decrease, while household income is forecasted to increase. In general, these trends are forecasted to result in a net reduction in natural gas use-per-customer. Overall, the residential use-per-customer is forecasted to decline by an annual rate of 0.4 percent through 2030. Table 3-5 includes an overview of the various growth rates in the forecast along with a comparison to the 2019 forecast. Figure 3-5 includes a chart with the historical use-per-customer along with the forecast through 2030. Note that 2012 and 2017 were particularly warm years, resulting in less-than-average natural gas use.

Table 3-5: Residential Use-Per-Customer Growth Rates

Natural Gas Residential UPC Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	-0.4%	-0.4%
10-Year Historical	-0.2%	-0.2%
5- Year Forecast	-0.4%	-0.4%
10-Year Forecast	-0.4%	-0.4%

Figure 3-5: Residential Use-Per-Customer Forecast



3.5.2.3 Residential Sales Forecast

The residential class used the following formula to forecast total natural gas sales:

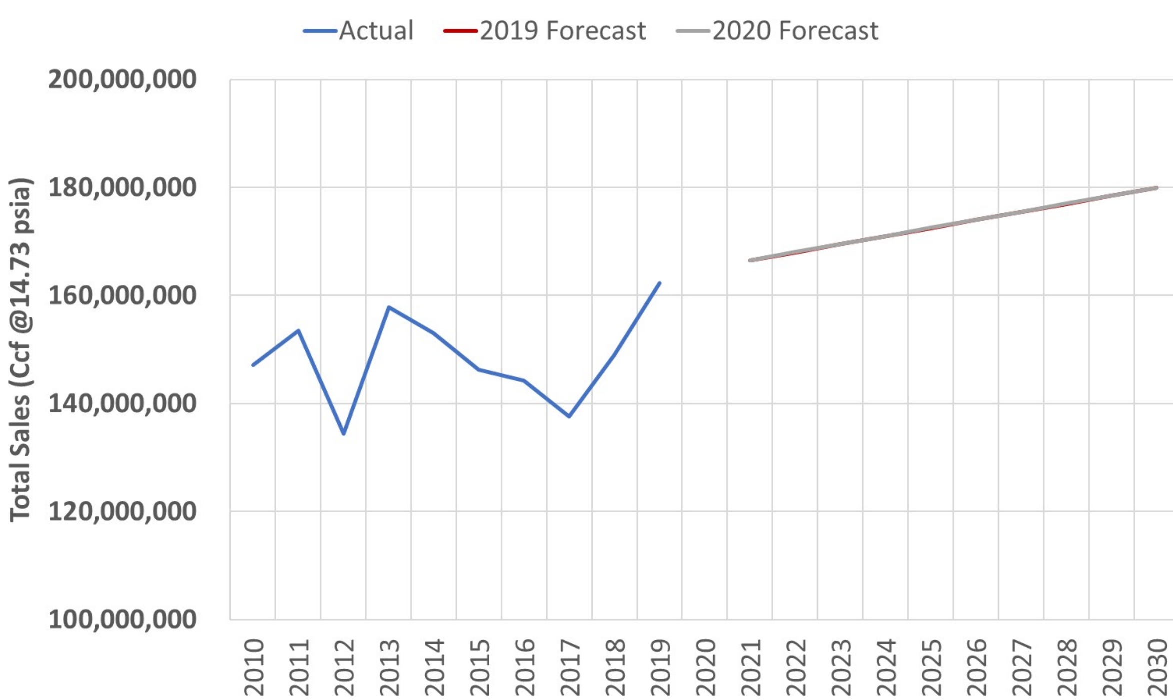
$$[Total\ Residential\ Sales] = [Use - Per - Customer] \times [\#\ of\ Customers]$$

This methodology was reviewed and determined to be more accurate than simply trending natural gas sales, which was the method used prior to 2014. Table 3-6 includes an overview of the various growth rates for the residential sales forecast along with a comparison to the 2019 forecast. Figure 3-6 includes a chart with the historical residential sales along with the forecast through 2030. Although long-term UPC is declining, this is offset by an increase in the size of the customer base due to population growth.

Table 3-6: Total Residential Sales Growth Rates

Natural Gas Residential Sales Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	1.2%	1.2%
10-Year Historical	1.5%	1.5%
5- Year Forecast	0.9%	0.9%
10-Year Forecast	0.9%	0.9%

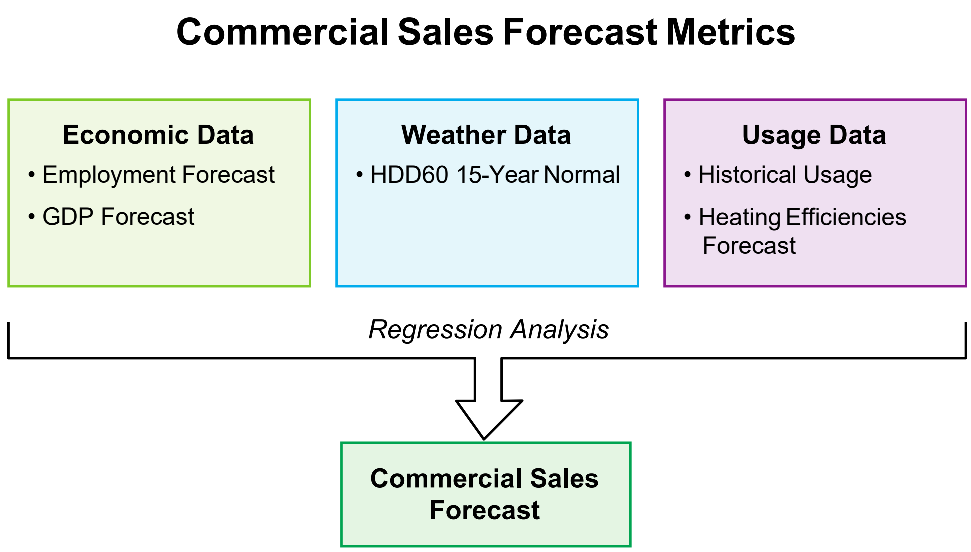
Figure 3-6: Total Residential Sales Forecast



3.5.3 Commercial Forecast

Customers in the commercial rate class primarily use natural gas to run their businesses. Commercial customers account for approximately 10 percent of Gas System customers and nearly 30 percent of the natural gas distributed via Springs Utilities distribution system. For commercial customers, there are four separate rate classes: small, large, seasonal, and indexed. Springs Utilities is responsible for maintaining sufficient supply, distribution, and demand resources for each of the commercial rate classes. The commercial demand forecast was developed via regression analysis, using historical customer growth and economic variables as inputs. Figure 3-7 includes an overview of the factors used to create the residential sales forecast. Note, unless specifically stated, "commercial" refers only to small and large commercial customers. Seasonal and indexed customers are noted at the end of this section.

Figure 3-7: Commercial Sales Forecast Metrics



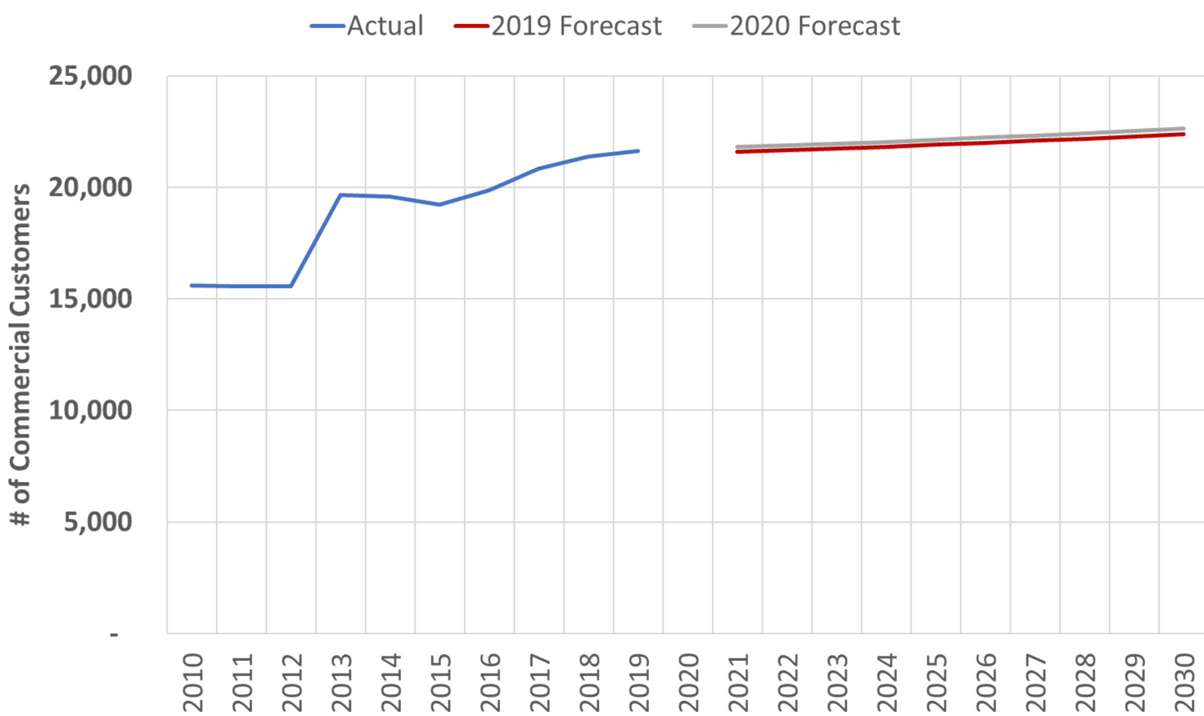
3.5.3.1 Commercial Customer Forecast

Based on the forecasted economic outlook, the number of commercial natural gas customers is expected to grow over the study period. Economic growth is the primary driver behind customer growth, and the number of commercial customers is expected to grow at an average rate of 0.4 percent through 2030. Table 3-7 includes an overview of the various growth rates in the forecast along with a comparison to the 2019 forecast. Figure 3-8 includes a chart with the historical number of commercial accounts along with the forecast through 2030. Note that following a 2012 sales audit approximately 4,000 residential customers were reclassified into the small commercial rate class beginning in 2013. This is the reason behind the sudden spike in commercial customers in 2013.

Table 3-7: Natural Gas Commercial Customer Growth Rates

Natural Gas Commercial Customer Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	-0.2%	0.8%
10-Year Historical	1.2%	1.2%
5- Year Forecast	0.3%	0.3%
10-Year Forecast	0.4%	0.4%

Figure 3-8: Natural Gas Commercial Customer Forecast



3.5.3.2 Commercial End Use Model

Like residential sales, commercial sales are heavily impacted by appliance efficiency standards. In this forecast, commercial sales were modeled using historical sales and other variables, rather than use-per-customer. The projected impact in the 10-year commercial forecast is a decrease of 0.8 percent due to increased efficiencies.

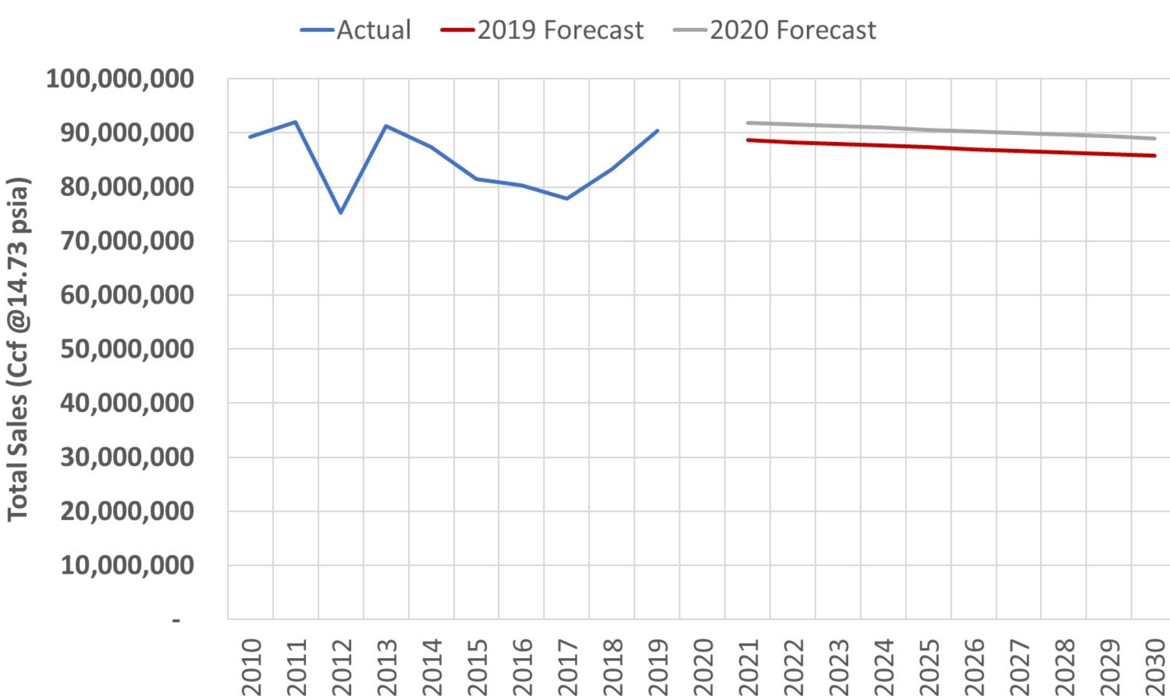
3.5.3.3 Commercial Sales Forecast

Although the end-use model is forecasting fewer sales per customer, this is offset by an increase in the size of the customer base due to economic growth. Increased appliance efficiency is partially offset by economic growth and a slight increase in commercial customers. Seasonal and indexed commercial sales, which are also commercial rate classes, are projected to be relatively flat compared to 2019 actual sales. Total commercial sales are projected to account for 30 percent of total throughput throughout the study period. Table 3-8 includes an overview of the various growth rates for the commercial sales forecast along with a comparison to the 2019 forecast. Figure 3-9 includes a chart with the historical commercial sales along with the forecast through 2030. 2020 sales are forecasted to be lower than 2019 due to the COVID-19 pandemic and a warmer-than-normal year for the first three quarters of 2020. The 2020 forecast is higher than the 2019 forecast due to actual growth rates outpacing the forecast.

Table 3-8: Natural Gas Commercial Sales Growth Rates

Natural Gas Commercial Sales Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	-0.4%	-0.4%
10-Year Historical	-0.4%	-0.4%
5- Year Forecast	-0.4%	-0.4%
10-Year Forecast	-0.4%	-0.4%

Figure 3-9: Natural Gas Commercial Sales Forecast



3.5.4 Other Sales Forecast

Industrial, military, and G4T customers currently account for less than 1 percent of total natural gas customers. Natural gas consumption for industrial, military, and G4T customers is 3 percent, 7 percent, and 5 percent, respectively, of total natural gas throughput. Industrial and military customer sales are forecasted to remain flat at 2019 levels through 2030.

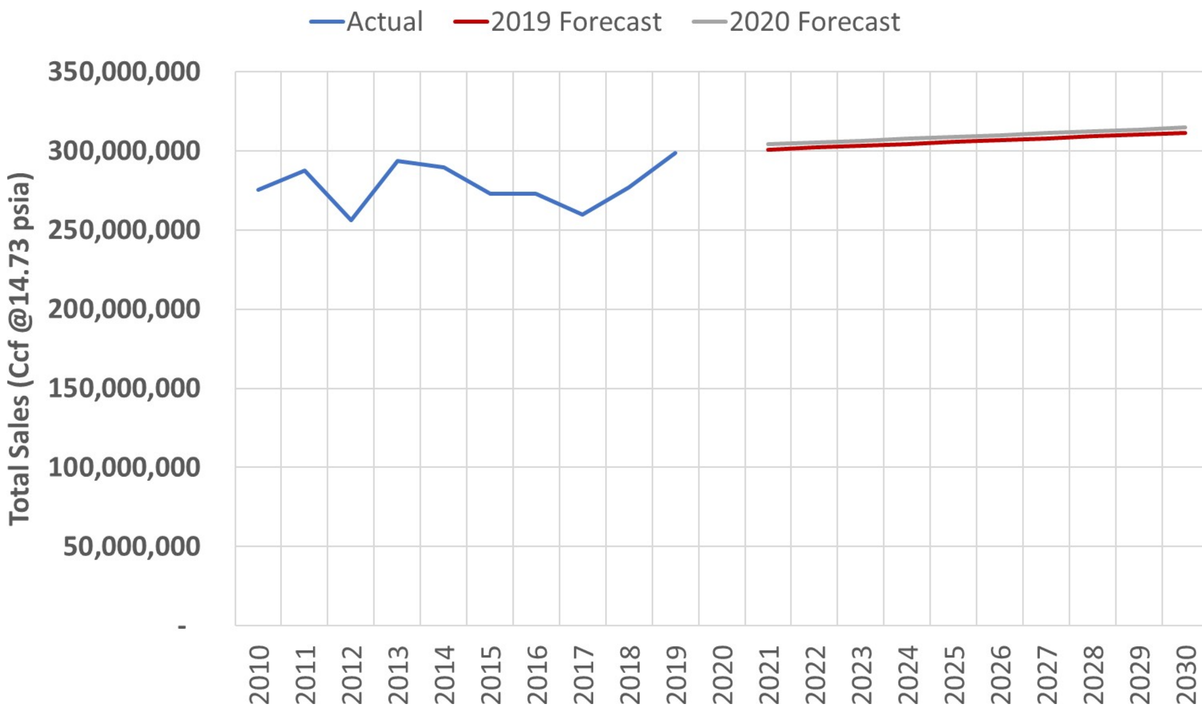
3.5.5 Total Annual Sales and Throughput

Sales and throughput forecasts for all the constituent rate classes were combined to create the total annual forecast. Table 3-9 includes an overview of the various growth rates for the sales forecast along with a comparison to the 2019 forecast. Figure 3-10 includes a chart with the historical sales along with the forecast through 2030. Overall, natural gas throughput is expected to grow at an annual average rate of 0.4 percent through 2030. Despite increased appliance efficiency, an expanding customer base is expected to offset increases in efficiency. Note the base forecast assumes typical weather conditions and growth consistent with the economic forecast. Extreme weather patterns or changes in economic conditions can impact forecasted natural gas consumption.

Table 3-9: Total Natural Gas Throughput Growth Rates

Natural Gas Total Throughput Growth Rates		
Forecast Time Frame	2019 Forecast	2020 Forecast
Current Year Forecast	0.4%	0.4%
10-Year Historical	1.0%	1.0%
5- Year Forecast	0.4%	0.4%
10-Year Forecast	0.4%	0.4%

Figure 3-10: Total Natural Gas Throughput Forecast



3.6 PEAK-DAY AND PEAK-HOUR FORECAST

Peak-day and peak-hour forecasts are used to assess the ability of the system to meet peak demand. Due to the large number of residential customers, natural gas consumption increases significantly with colder weather and elevated wind speeds. To ensure an adequate supply of natural gas during peak demand scenarios, Springs Utilities forecasts and plans natural gas resources for a one-in-twenty-five-year cold weather event. Forecasts for peak-day and peak-hour demand are developed for the one-in-twenty-five-year weather scenario and are utilized for peak-day and peak-hour capacity planning. The following sections detail the methods and results for the peak-day and peak-hour demand forecasts.

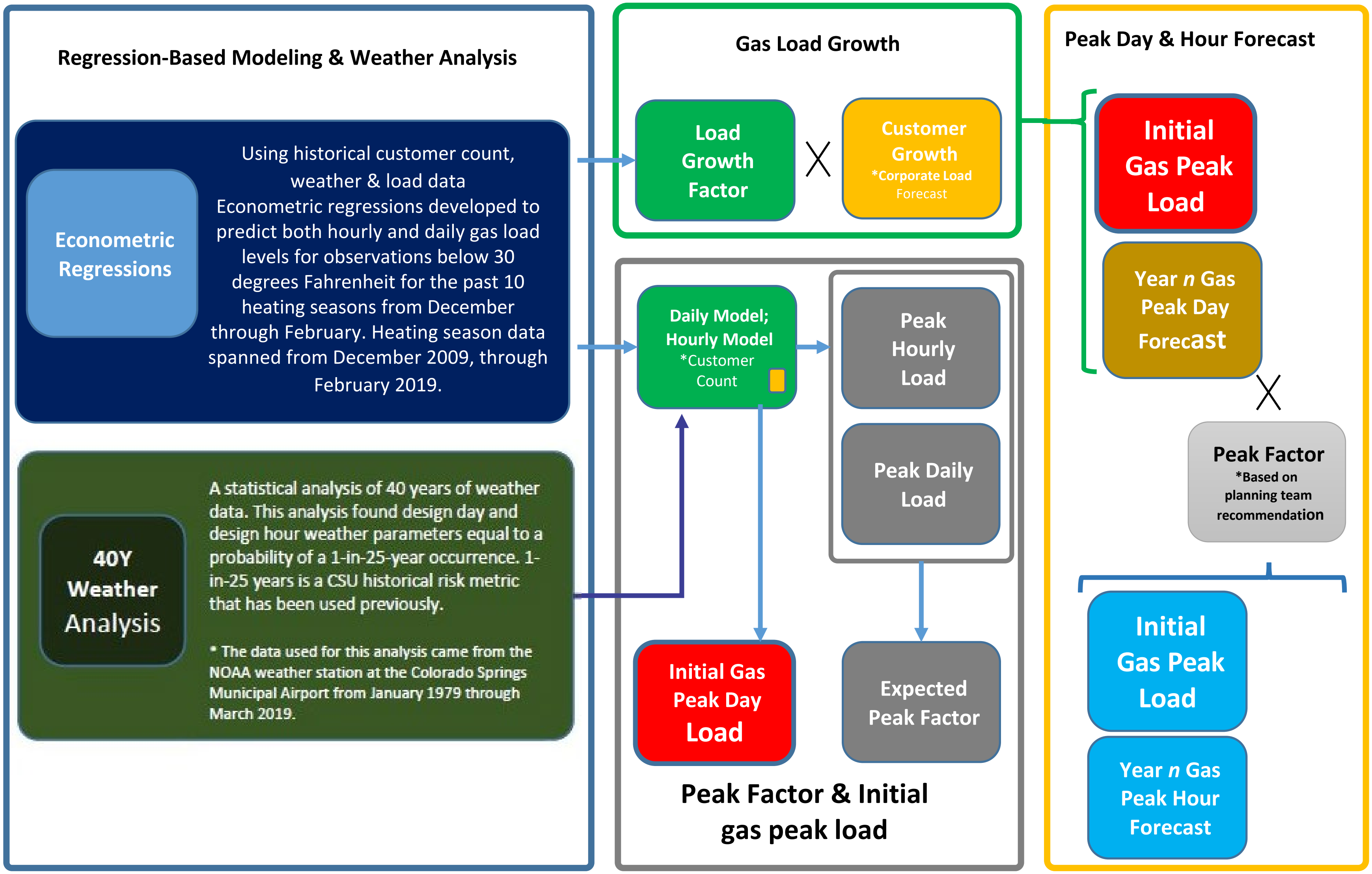
3.6.1 Forecast Methods

Historical trends can generally provide a reliable baseline to evaluate forecasted demand for natural gas. However, the industrial base in Colorado Springs is relatively small compared to cities of a similar size. Because of this, Springs Utilities natural gas consumption is predominantly driven by weather-sensitive heating loads. Weather in Springs Utilities service area can be extremely volatile, which, in turn, makes forecasting daily and hourly natural gas demands a challenging process. One of the key results of the 2020 GIRP was a revision in forecast methodology that improved the correlation between the forecast and actual peak-day and peak-hour events. In preparation for the 2020 GIRP, an extensive weather and load study was performed in 2018 through 2019. The load study utilized multi-factor regression analysis to create the 30-year load forecast. Actual daily and hourly load data was captured from Springs Utilities system for the 2009 through 2018 heating seasons. 40 years of historical weather data was also gathered from the National Oceanic and Atmospheric Administration's Colorado Springs station for 1979 through 2019. The process for developing the peak-day and peak-hour forecasts is included in Figure 3-11. At a high level, regressions were developed for historical weather, consumption, and customer data to develop weather, load growth, peak factor, and demand profiles. Load growth, peak factor, and customer forecasts were then incorporated into a demand model to generate daily and hourly peak load forecasts. The following factors emerged as key parameters in the regression equations for daily and hourly load calculations:

- Heating Degree Days
- Dew Point
- Wind Speed
- Customer Count
- Day of week
- Prior day / prior hour data

These factors were incorporated into the forecast methodology and are reflected in the final peak-day and peak-hour forecasts.

Figure 3-11: Peak-Day and Peak-Hour Forecast Process



3.6.2 Revised Planning Assumptions

Previous GIRP forecasts did not use hourly data as part of the load forecast. With the addition of hourly data, it was determined the peak factor (peak hourly load divided by the peak daily load) is 5 percent instead of the previously used 5.3 percent planning criteria. Additionally, daily load growth was determined to only be approximately 50 percent of the growth in customer numbers versus the previous assumption of 100 percent. Historic peak hourly data indicated a 5.1 percent peak factor, so the 5.1 percent peak factor was adopted for planning purposes. This is a reduction from the previously used 5.3 percent peak factor used in previous GIRPs.

3.6.3 Peak Demand Forecast

Using the procedure and factors previously discussed, the peak-day demand forecast additionally used an average temperature of -13°F and wind speed of 12 mph. The peak-hour forecast was derived from the peak-day forecast by applying the 5.1% peak factor from the load study. Table 3-10 includes the peak demand forecast for the 2020-2021 heating season.

Table 3-10: 2020-2021 Heating Season Peak Demand Forecast

2020-2021 Heating Season Peak Demand Forecast with Adjusted G4T and IT		
Daily Peak (Dth/Day)	Hourly Peak (Dth/Hour)	Base Peak Factor
279,401	14,349	5.1%

To account for the growing customer base, the peak demand forecast was combined with anticipated customer growth to determine the expected peak-demand over the thirty-year planning horizon. Table 3-11 includes the peak-day and peak-hour demand forecast along with anticipated customer growth for the study period. Note loads included in the table excluded adjust G4T and IT customer loads.

Table 3-11: Peak Demand Forecast

Thirty-Year Peak Demand Forecast			
Winter	**Daily Peak (Dth/Day)**	**Hourly Peak (Dth/Hour)**	**Customer Growth Rate**
2019/2020	277,631	14,259	1.20%
2020/2021	279,401	14,349	1.20%
2021/2022	281,181	14,440	1.20%
2022/2023	282,973	14,531	1.20%
2023/2024	284,775	14,623	1.20%
2024/2025	286,588	14,716	1.20%
2025/2026	288,412	14,809	1.20%
2026/2027	290,247	14,902	1.20%
2027/2028	292,092	14,997	1.20%
2028/2029	293,949	15,091	1.20%
2029/2030	295,506	15,171	1.00%
2030/2031	297,070	15,250	1.00%
2031/2032	298,643	15,331	1.00%
2032/2033	300,223	15,411	1.00%
2033/2034	301,811	15,492	1.00%
2034/2035	303,407	15,574	1.00%
2035/2036	305,011	15,655	1.00%
2036/2037	306,623	15,738	1.00%
2037/2038	308,243	15,820	1.00%
2038/2039	309,871	15,903	1.00%
2039/2040	311,507	15,987	1.00%
2040/2041	313,152	16,071	1.00%
2041/2042	314,805	16,155	1.00%
2042/2043	316,466	16,240	1.00%
2043/2044	318,135	16,325	1.00%
2044/2045	319,812	16,410	1.00%
2045/2046	321,498	16,496	1.00%
2046/2047	323,193	16,583	1.00%
2047/2048	324,896	16,669	1.00%
2048/2049	326,607	16,757	1.00%
2049/2050	328,327	16,844	1.00%
2050/2051	330,056	16,933	1.00%

Figure 3-12 includes a comparison of the 2020 GIRP peak-day forecast and the 2015 GIRP peak-day forecast. Figure 3-13 includes a comparison of the 2020 GIRP peak-hour forecast and the 2015 GIRP peak-hour forecast. Note the significant decrease in peak day and peak hour forecasts from the 2015 GIRP to the 2020 GIRP. This was driven by a revision in the forecast methodology that better correlated forecasts with actual peak-day and peak-hour events. The reduction of the peak factor from 5.3% to 5.1% and assuming 50% of the customer growth drove the reduction in both the peak-hour forecast and peak-day forecast. The revised assumptions are used with a one-in-twenty-five-year cold weather event to assess resource adequacy. The revised peak-hour forecast resulted in a significant postponement of new infrastructure to serve customer growth.

Figure 3-12: Natural Gas Peak-Day Forecast

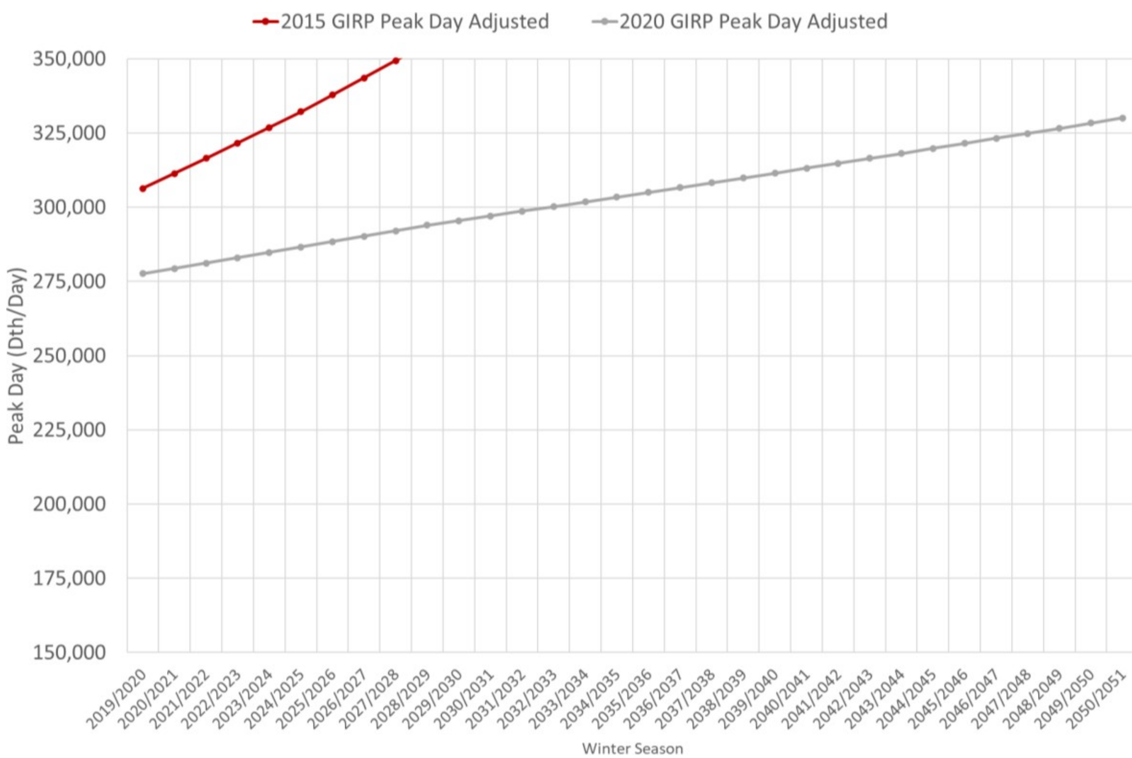
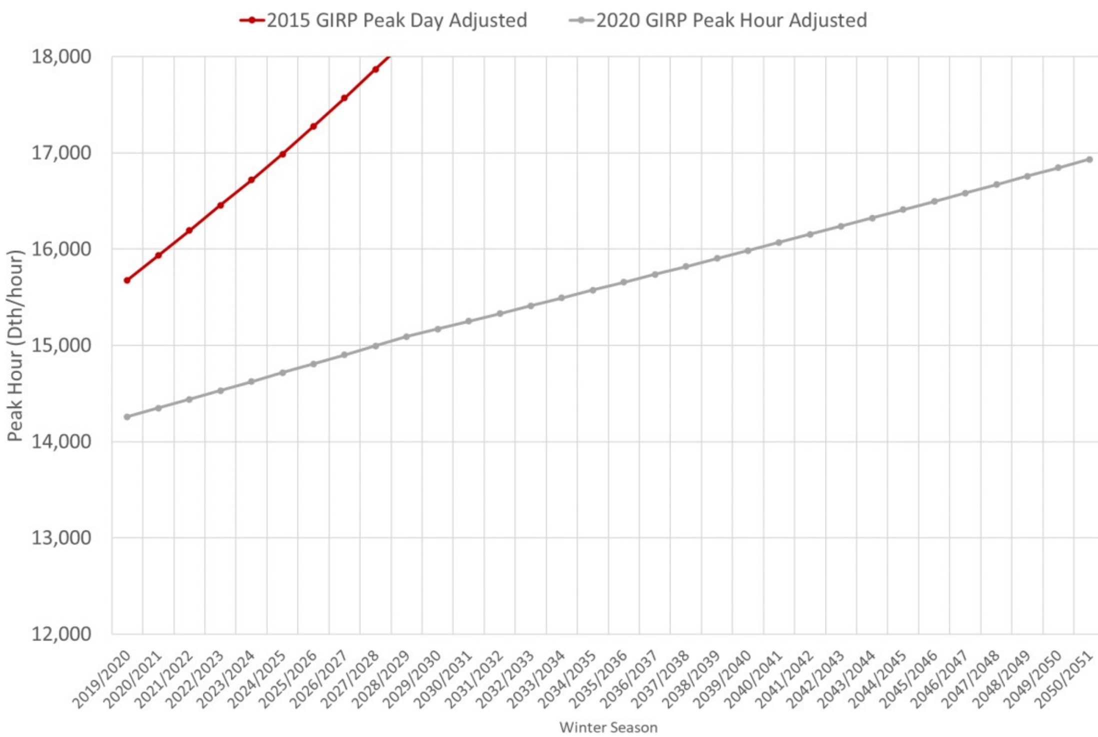


Figure 3-13: Natural Gas Peak-Hour Forecast



4.0 EXISTING NATURAL GAS SUPPLY

Springs Utilities manages a diversified portfolio of natural gas supply resources that includes Propane Air Plant capacity, contracts to purchase natural gas from multiple supply basins, multiple contracts for pipeline transportation, and three different natural gas storage services. Additionally, Springs Utilities manages several demand-side resources to meet customer demand under extreme weather or load conditions.

4.1 EXISTING RESOURCES

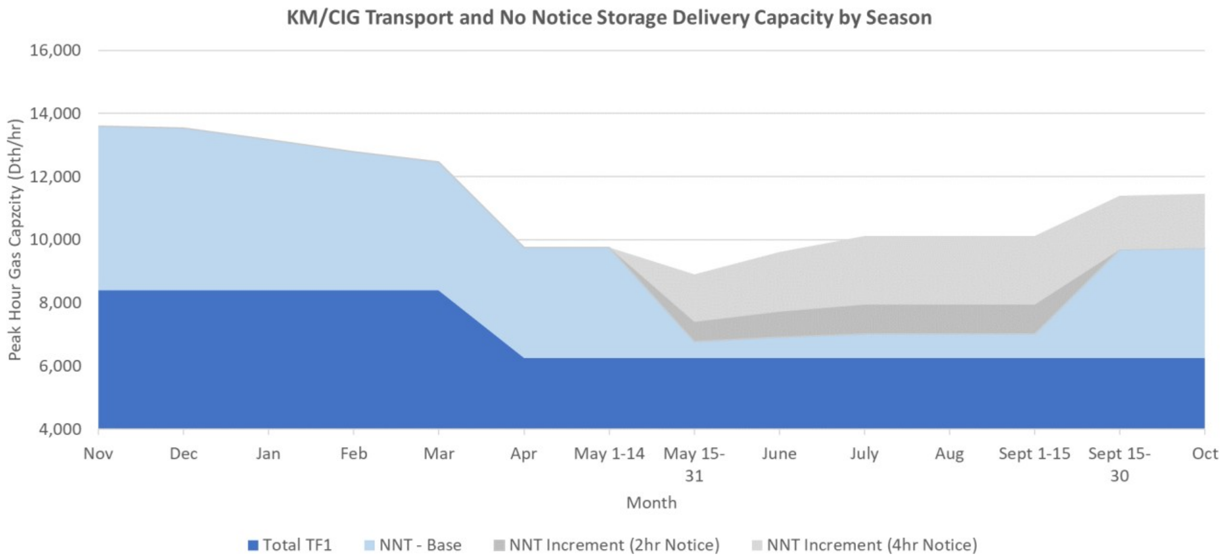
As part of meeting customer requirements, Springs Utilities currently has multiple contracts for natural gas supply, pipeline transportation, storage services and a propane air facility owned and operated by Springs Utilities. A summary of Springs Utilities existing natural gas supply resources for the 2020-2021 heating season is included in Table 4-1. These are the total amounts on which the system relies to cover its demand needs, including peak demand.

Table 4-1: 2020-2021 Heating Season Peak Resources

Maximum Transport / Propane Air Resources		
Resource	**Maximum Daily Quantity (Dth/day)**	**Peak Hourly Entitlement (Dth/hr)**
Transportation		
CIG Mainline	122,936	5,122
CIG Cheyenne	78,375	3,266
Total Transport	201,311	8,388
Storage		
CIG NNT Storage	75,325	5,210
Total CIG Transport + Storage	276,636	13,598
Propane-Air Plant		
Propane-Air Full Day	35,814	1,800
Total Peak Day Delivery Capacity	312,450	15,398

The available transport capacity on the KM/CIG system varies by season as some transport contracts are seasonal and the no notice transport capacity varies by the amount of gas in inventory. No Notice Service ("NNT") also has some peaking factors that vary by time of year and whether there is no notice, two-hour notice, or four-hour notice. Figure 4-1 illustrates the currently contracted variations in transport capacity.

Figure 4-1: Seasonal KM/CIG Capacity by Season



4.1.1 Annual Gas Supply Acquisition Requirements

Springs Utilities manages its' natural gas acquisition and related activities on a system-wide basis, utilizing several regionally available supply options needed to serve customers. Structuring the gas contract portfolio to meet the load shape is essential from both a reliability standpoint and an economic standpoint. Since the gas load of Springs Utilities can swing from a winter high of over 278,000 Dth/day to a summer low of 18,000 Dth/day it is important that supply contracts effectively address the seasonal variation in gas demand.

In the winter, the utility typically has a portfolio of gas contracts that includes "base load" supplies that provide uniform daily supply volumes over a month or longer, and "swing" or "peaking" contracts that can be called on a day-to-day basis as needed. Master agreements are also maintained with many suppliers to buy daily "spot" supplies as loads vary. While both swing and spot supplies are scheduled daily, swing contracts allow the buyer firm rights to the underlying supply, while spot contracts are only on an "as-available" basis. Many variations on these contracts are negotiated, including different term (length of contract), receipt locations, market price formula, and other volume and price adjustments. The data below shows the diversity in the number and type of supply contracts held by Springs Utilities.

- **Number of Supplier Contracts:** 37
- **Contracted Base Load Supplies:** 5
- **Contracted Swing Supplies:** 2
- **Spot Supplies:** Variable

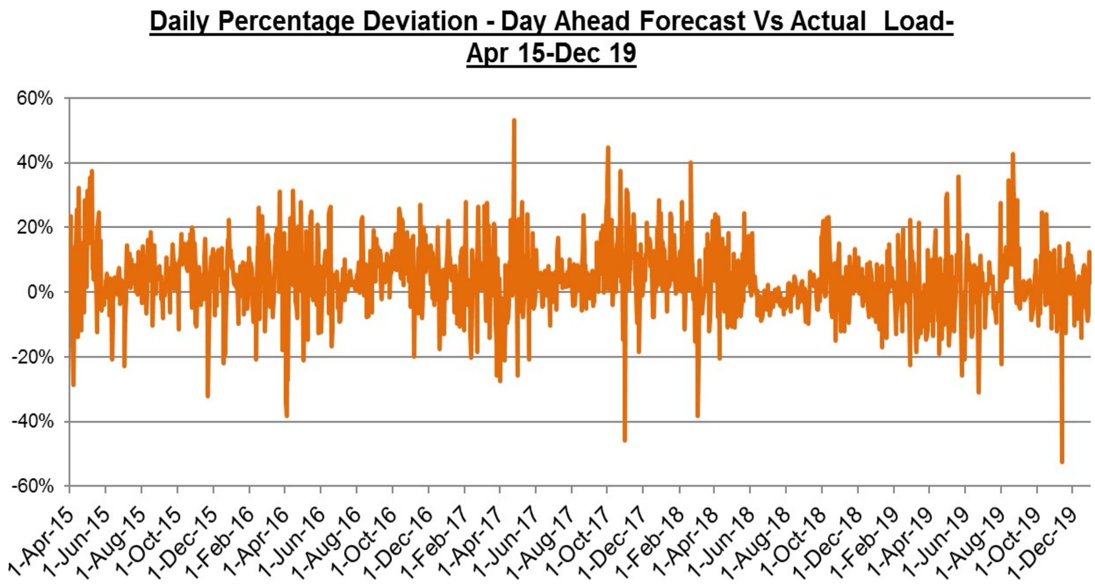
Since natural gas supply prices are not regulated, prices are negotiated competitively between buyers and sellers in active markets. Most gas supply prices are negotiated relative to spot "index" prices, which are calculated by independent publishers for actual transactions occurring for the daily and monthly periods of interest.

4.1.1.1 Load Deviations

As mentioned earlier, matching supply resources with daily and hourly load requirements on Springs Utilities distribution system is quite challenging with the diverse weather events that occur in Colorado Springs and along the Front Range. Weather changes occur rapidly, even within a gas day period, especially in the shoulder months of November and April.

Figure 4-2 illustrates the load deviation of the day ahead forecast versus actual load for the three-year period April 2015 to December 2019. Note the forecasted versus actual load can vary by as much as 60%. The daily weather volatility requires appropriate assets and timing to respond to the daily and hourly needs.

Figure 4-2: Daily Load Deviation



Daily load deviation for the period November-March illustrates the LDC load volatility that requires active day to day management of supply acquisition and nomination.

4.1.2 Supply Management

There are several complexities in the exiting CIG tariffs and contracts that require active day-to-day management to supply natural gas to the CIG interstate transmission pipeline system. This includes day-ahead planning along with intraday monitoring and adjustments. Gas supplies and transportation must be nominated each day, and volumes must be balanced and accounted for within CIG's tariff requirements. Daily balancing is required and accomplished using storage facilities to account for over- and under-volumes delivered by suppliers to the CIG system. In natural gas trading, the gas day for accounting and balancing purposes starts at 8:00 am and goes through 8:00 am the following day. This is one of the main challenges in natural gas trading because a gas day ending at or near the peak hour makes it difficult to anticipate the peak-hour during rapidly changing weather conditions or a significant weather forecast error.

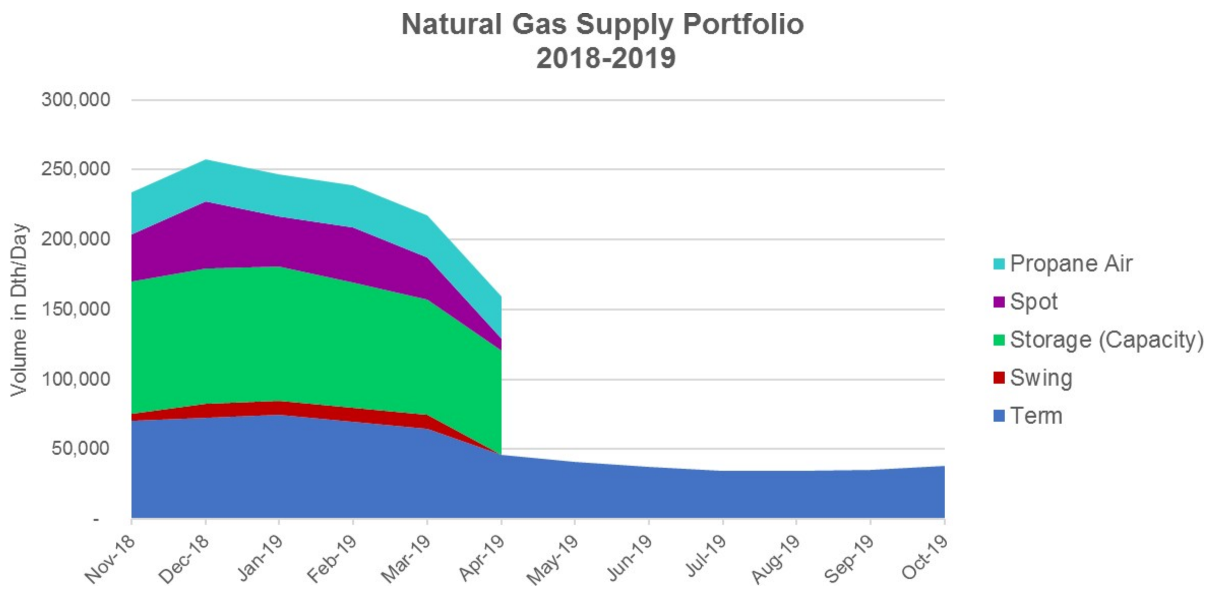
4.1.3 Supply Portfolio Overview

Springs Utilities gas supply portfolio is diversified to balance changing market conditions and the risk of production cuts while maintaining reliable deliveries. Term base-load volumes are purchased under contracts ranging from one month to 30 years. The base load contracting approach for the heating season, November through April, is to cover the expected customer base-load requirements. For the other period May-October, the approach is to have firm contracted supplies to cover the summer customer base load and storage injection volumes.

Approximately 20% of the monthly base-load supply is acquired through a pre-paid 30-year supply contract executed in October 2008. Pre-paid gas supply contracts are funded by revenue bonds at below market prices. Springs Utilities existing pre-paid contract yields approximately a $5 million annual savings.

Swing supplies are firm supply contracts with volumes nominated daily and are usually priced on a market price index. Spot supplies are negotiated daily at daily market rates. Figure 4-3 illustrates the composition of the Gas Portfolio for the 2014/2015 heating season. The portfolio is designed for the peak day and it is adjusted daily to meet customer needs.

Figure 4-3: 2019 Daily Supply Portfolio



*Note the additional supply for the heating season (November –April). For the May-October period minimal supplies are planned as significantly less gas is used in the summer months.

4.1.4 Commodity Resources

Since transportation pipelines do not sell physical natural gas supplies, gas supply for Springs Utilities system is purchased from natural gas production owners or brokers (marketers). The natural gas supply market is robust and fluid, with electronic commodity trading platforms. Springs Utilities maintains an active and competitive gas trading and scheduling group that negotiates up to $97 million per year in gas purchases for its retail gas needs. At any one time, Springs Utilities has many active contracts with producers to allow for competitive pricing negotiations and diverse sources of supplies for optimal pricing and delivery risk diversification.

Subscriptions are also maintained with online trading platforms, and many market and industry publications providing market intelligence and fundamental and statistical market data. Springs Utilities gas traders and schedulers work on a trading floor with electric traders facilitating fast and accurate exchange of information to leverage the benefits of a multiservice utility based on real-time price opportunities. This organizational structure helps make Springs Utilities competitive in the daily and longer-term natural gas markets. Although, substantial gas supply is bought and sold in the daily market, Springs Utilities utilizes an annual request for proposals (RFP) process for long term and highly structured gas supply contracts. The combination of longer-term purchases, highly structured purchases and daily purchases provide a diversified natural gas portfolio.

Springs Utilities has a natural gas acquisition process that seeks to competitively acquire natural gas supplies while reducing exposure to short term price volatility. The acquisition strategy includes storage capacity, term purchases and spot purchases. Although the specific provisions of the plan are dynamic as a result of ongoing changes in market fundamentals, the following principles guide development of the acquisition plan. Springs Utilities utilizes a portfolio approach for long-range planning. This approach reduces risk by allowing for comparison of various supply options and sensitivity analysis can identify risks and benefits of various portfolio options. Utilities additionally focuses on procuring a diverse set of natural gas supply resources to not expose Springs Utilities customers too greatly to one single supply source. The emphasis on diversity reduces risk and additionally provides lower average commodity prices, translating to lower costs to meeting Springs Utilities customer needs.

4.1.5 Transportation Resources

Since transportation pipelines do not actually sell physical natural gas supplies, gas supply for Springs Utilities system is purchased from natural gas production owners or brokers (marketers). The Colorado Interstate Gas Company pipeline is the only interstate pipeline serving Colorado Springs. CIG provides a variety of services with differing levels of reliability, availability, and cost. Springs Utilities assembles a portfolio of contracted services tailored to meet the specific needs of its customer base on annual, heating season, daily, and hourly time frames. Springs Utilities executes primarily long-term contracts with CIG for the various services needed, and then manages them on a day-by-day basis according to CIG's tariff requirements.

The contracts identify specific locations to have supplies accepted on CIG's system (e.g., in the production areas) and locations where supplies are delivered to Springs Utilities (i.e., city gate stations and storage locations). Gas supplies accepted onto CIG's pipeline and transported to Springs Utilities gate stations and storage facilities must be nominated each day through a structured procedure with two nomination cycles, approximately 19 and 15 hours in advance of the gas day. Limited changes can be made in the three "intraday" nomination cycles during the gas day.

Springs Utilities transportation contracts are managed as an asset portfolio and represent a major cost component of the overall gas asset portfolio. Each time a new CIG "rate case" is pending before the Federal Energy Regulatory Commission (FERC), Springs Utilities intervenes and represents its customer's interests in an effort to negotiate lower rates. Contract terms are typically five years or longer with specific renewal rights, and often with different termination dates. This provides flexibility in restructuring transport contracts to meet the changing needs of the utility. While delivery capacity rights are purchased for supply reliability, rate negotiations and restructuring of expiring contracts and acquisition of new contracts forms the framework for obtaining economic (cost) efficiencies are a key part of portfolio management.

4.1.6 Storage

An essential supply source for Springs Utilities system needs is contracted storage. Natural gas is stored in underground formations and the typical economic model is to inject gas in the summer during a lower market price environment, then withdraw it in the winter, offsetting the higher winter price environment. However, the real benefit of storage is enhancing a utility's ability to balance supply and demand and leverage it to meet peak hour demands. Most utilities (including Springs Utilities) use traditional natural gas storage to manage the variability required to meet customer needs on a day-to-day basis. Storage provides flexibility as loads vary over weekends and holidays when spot market supplies may not be available, as well as managing unpredicted load changes due to weather volatility, unplanned outages, or maintenance issues.

Storage capacity, as a key gas asset portfolio component, requires active daily and seasonal management. During weekends and holidays when there typically is no active gas trading market, storage is used to shape gas supply availability to meet predicted demand requirements and to address short-term unpredicted load changes. Purchasing gas directly from suppliers and transporting it to the LDC (without storage) requires a specific receipt and delivery commitment by both parties for a specific period to ensure proper upstream operations. Since gas well delivery capacity cannot easily be regulated up and down on a real time basis, storage capacity serves as a valuable tool in managing those demand and supply swings resulting from rapidly changing weather patterns.

Springs Utilities maintains two types of gas storage service. The first is a "scheduled" traditional service. Both the Young Gas Storage service agreement and the Tallgrass Storage service agreement require Injections and withdrawals to be "scheduled" over one to five different cycles for each delivery day.

The second storage service is a "no-notice" service, provided for under the no-notice transportation (NNT) rate schedule offered by CIG. No-notice storage serves as a critical balancing tool, since NNT service is not required to be scheduled ahead of time. Thus, the injections and withdrawals under this service manage the net imbalances in pipeline deliveries versus actual consumption by the LDC's customers.

Functionally, if all supplies (other than NNT) received by CIG and delivered to Springs Utilities during a given day are higher than demand, the difference is automatically injected into NNT storage. If supplies are lower than demand, the difference is automatically withdrawn from NNT storage. Another feature of

NNT is the ability to cover large aberrations in hourly loads. Typically, early morning hours (between 6:00 a.m. and 9:00 a.m.) represent much higher hourly loads than the hourly average for the entire day requiring flexible supply capability during those hours to meet changing load demands. NNT service is more expensive than interruptible or firm service and effective use of scheduled storage lowers costs to Springs Utilities customers.

NNT Storage service is served by four CIG storage facilities. Fort Morgan, Latigo, and Flank fields are in eastern and southeastern Colorado. Boehm field is in southwest Kansas. The Young scheduled storage facility is located northeast of Denver physically feeds into CIG's system at a specific receipt point on a portion of Springs Utilities pipeline transportation entitlements. In addition, Huntsman Storage – thru the Tallgrass pipeline system is another source of gas supply.

4.1.7 Propane Air Plant

Springs Utilities propane air (PA) plant is a supply source located on the distribution system to provide supplemental supply during extreme peak weather conditions or potential interruptions of Springs Utilities contracted gas deliveries to CIG's pipeline system. The PA plant was built in 1973-74 and is located near CIG's North Colorado Springs gate station on the east side of Colorado Springs.

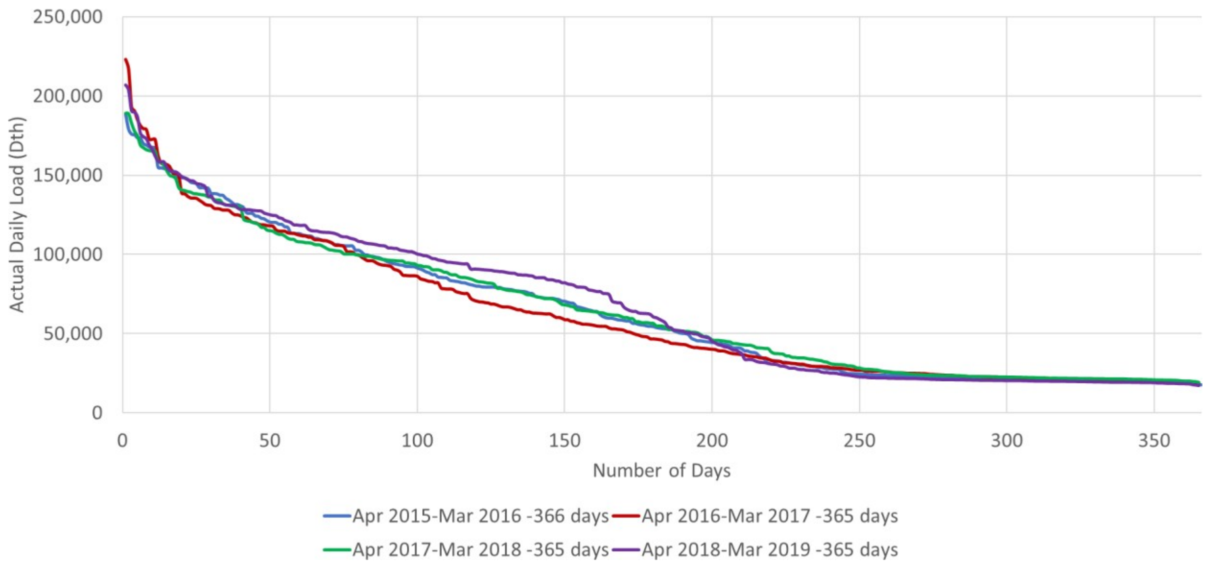
There are forty-two 30,000-gallon (water capacity) propane tanks at the site holding a little over one million gallons of propane working storage. The plant can produce up to 1,800 Dth per hour (35,000 Dth/day) of propane-air gas designed to be compatible with the natural gas feeding the Colorado Springs service area. At this rate, the plant has nearly three days of full production capacity. In recent years, the plant has become a critical facility for managing peak-hour requirements, as well as the traditional peak-day requirements.

4.2 ASSET OPTIMIZATION

Gas supply assets (transportation, storage, and supply contracts) represent a major annual operating expense for Springs Utilities. Since most supply assets are structured around a straight "fixed/variable" rate design, the contract holder pays for the service's fixed costs on a year-round basis and variable costs on a volumetric use basis. Gas distribution companies, like Springs Utilities, are required to have sufficient capacity available for meeting peak load requirements. Thus, on occasion, surplus capacity is available for optimization when market conditions exist, and that surplus capacity can be released for sale to the open market on a day-to-day basis. Any proceeds resulting from this optimization are returned to Springs Utilities customers through lower rates. The amount of asset optimization varies from year-to-year depending on market conditions. Springs Utilities does not engage in speculative trading of gas supplies, as dictated by the Utilities Board governance policy Executive Limitation 11 – Enterprise Risk Management.

The load duration curve in Figure 4-4 illustrates demand level versus frequency of four typical 365-day time periods. Notably, on average there were only five days where the actual load was above 180,000 Dth/day for the four selected time periods.

Figure 4-4: Load Duration Curve April 2015 – March 2019



4.3 BALANCE OF LOADS AND RESOURCES

Ideally, peak-day and peak-hour forecasts are used to assess the adequacy of current transportation capacity, storage deliveries, and on-system propane-air production against future demand and demand-side management resources. Under current contracts and resources, Springs Utilities has a maximum daily delivery capacity of 317,089 Dth per day and an hourly maximum of 15,331 Dth per hour. Table 4-2 includes the peak-day and peak-hour forecasts along with the anticipated daily and hourly supply shortfalls. Current hourly supply resources are expected to be insufficient by the 2032-2033 heating season, while daily supply resources are projected to remain sufficient until the 2043-2044 heating season. Note the projected shortfalls are after adjustments for G4T and IT customers.

Table 4-2: Projected Peak Demand and Projected Supply Shortfalls

Projected Peak Demand and Supply Shortfalls				
Winter	Projected Peak Demand		Projected Shortfalls	
	Daily Peak (Dth/day)	Hourly Peak (Dth/Hour)	Daily Shortfall (Dth/day)	Hourly Shortfall (Dth/Hour)
2020/2021	279,401	14,349	-	-
2021/2022	281,181	14,440	-	-
2022/2023	282,973	14,531	-	-
2023/2024	284,775	14,623	-	-
2024/2025	286,588	14,716	-	-
2025/2026	288,412	14,809	-	-
2026/2027	290,247	14,902	-	-
2027/2028	292,092	14,997	-	-
2028/2029	293,949	15,091	-	-
2029/2030	295,506	15,171	-	-
2030/2031	297,070	15,250	-	-
2031/2032	298,643	15,331	-	-
2032/2033	300,223	15,411	-	**(13)**
2033/2034	301,811	15,492	-	**(94)**
2034/2035	303,407	15,574	-	**(176)**
2035/2036	305,011	15,655	-	**(257)**
2036/2037	306,623	15,738	-	**(340)**
2037/2038	308,243	15,820	-	**(422)**
2038/2039	309,871	15,903	-	**(505)**
2039/2040	311,507	15,987	-	**(589)**
2040/2041	313,152	16,071	-	**(673)**
2041/2042	314,805	16,155	-	**(757)**
2042/2043	316,466	16,240	-	**(842)**
2043/2044	318,135	16,325	**(1,046)**	**(927)**
2044/2045	319,812	16,410	**(2,523)**	**(1,012)**
2045/2046	321,498	16,496	**(4,007)**	**(1,098)**
2046/2047	323,193	16,583	**(5,499)**	**(1,185)**
2047/2048	324,896	16,669	**(6,998)**	**(1,271)**
2048/2049	326,607	16,757	**(8,504)**	**(1,359)**
2049/2050	328,327	16,844	**(10,018)**	**(1,446)**
2050/2051	330,056	16,933	**(11,540)**	**(1,535)**

Figure 4-5 contains a comparison of forecasted daily peak demand with current supply resources. Note the total demand is decreased to reflect G4T and IT customer loads. Capacity of the existing PAP is constrained by available blending capacity through North Gate Station. Springs Utilities has a shortage of supply resources starting in the winter of 2043-2044.

Figure 4-5: Peak-Day Forecasted Load and Supply

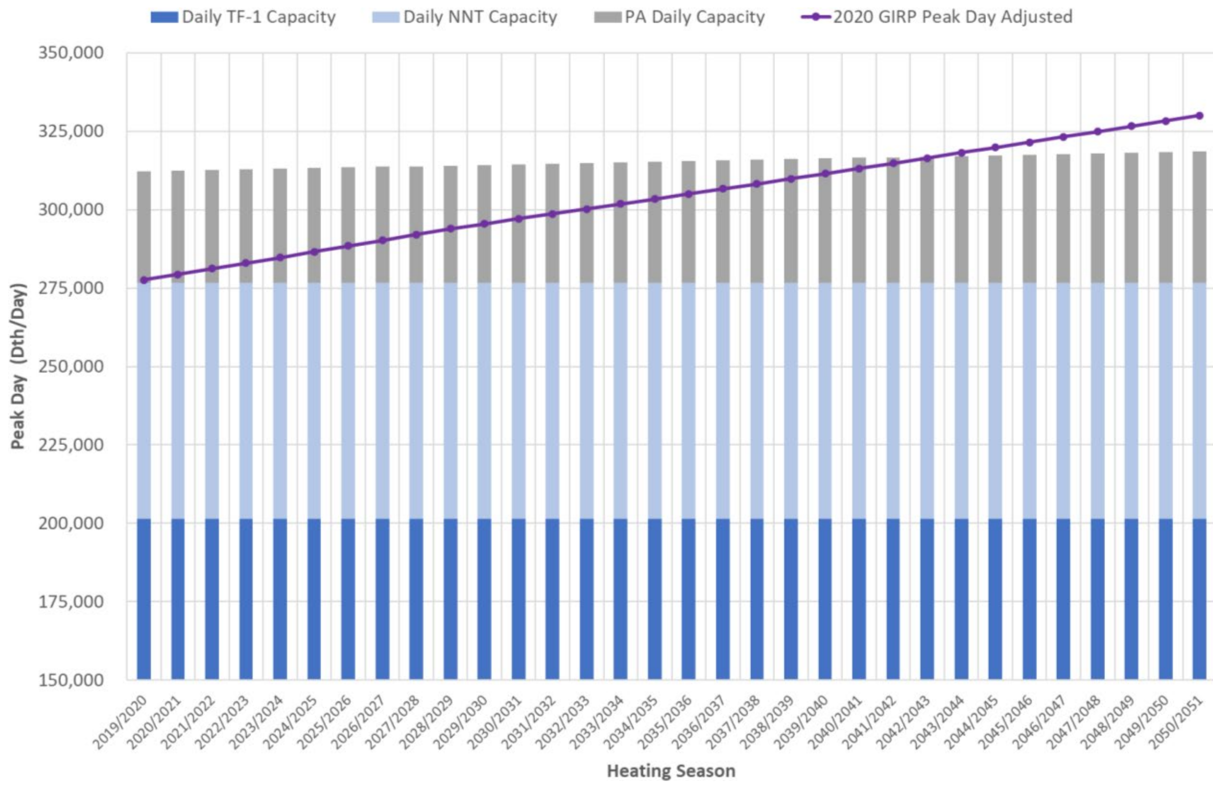
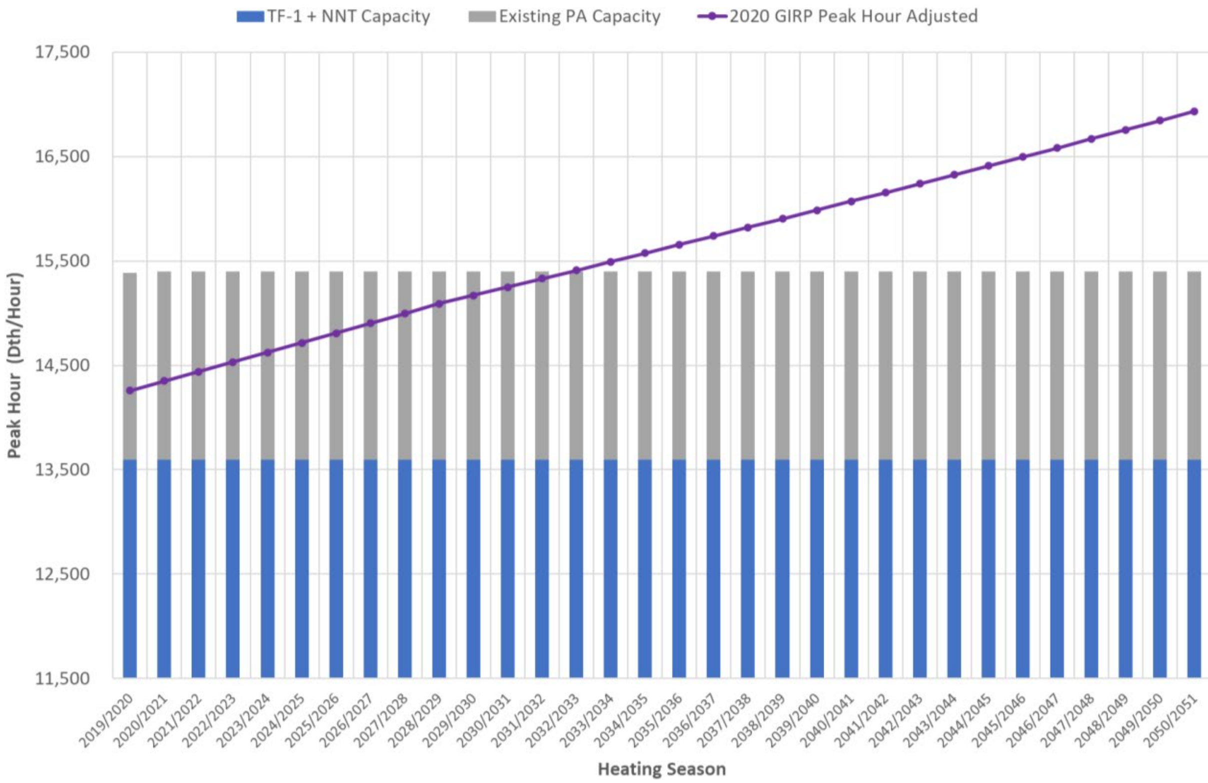


Figure 4-6 contains a comparison of forecasted hourly peak demand with current supply resources. Note a shortage of contracted capacity occurs starting in the winter of 2032-2033. The shortage indicates that Springs Utilities would not be able to guarantee sufficient natural gas to all customers without incurring pipeline penalties, particularly in the event of extreme weather. Supply side and demand-side alternatives to alleviate the forecasted shortage are discussed in following sections of this report.

Figure 4-6: Peak-Hour Forecasted Load and Supply



5.0 SUPPLY SIDE ANALYSIS

As a Local Distribution Company ("LDC"), Springs Utilities does not own natural gas fields or intrastate/interstate transportation pipelines. Springs Utilities manages a diversified portfolio of natural gas supply resources that include: Propane Air Plant capacity, contracts to purchase natural gas from multiple supply basins, multiple contracts for pipeline transportation, and three different natural gas storage services.

On an annual, monthly, daily, and hourly basis, Springs Utilities procures and contracts a natural gas supply to meet customer demands. On a long-term basis, Springs Utilities contracts for delivery capacity and storage services to adequately serve the Colorado Springs community. In addition to supply contracts, Springs Utilities operates a Propane Air Plant ("PAP") to meet customer's firm requirements during peak-days and peak-hours. Moreover, Springs Utilities goal is to hold a diversified portfolio of pipeline transportation and storage services to meet its supply obligations.

5.1 TRADITIONAL SUPPLY SIDE OPTIONS

In this section several options and solutions to meet future supply requirements are listed below. These alternatives represent the normal growth of supply assets necessary to meet projected utility load growth over an intermediate planning horizon. Each alternative is evaluated by considering cost, reliability, and functionality within the portfolio, time to put in service, and strategic benefits.

5.1.1 CIG Tariff Allowances

The existing CIG tariff allows for overages of up to 1,000 Mscf per hour, provided the CIG system is not capacity constrained. This option is subject to capacity availability and is not a guaranteed long-term capacity solution.

5.1.2 Temporary Capacity from Other LDCs

Temporary capacity may be available from another LDC on a short-term basis (one or two heating seasons). Temporary capacity is likely to be non-firm and would likely require additional air blending capacity at an additional cost. This option is subject to availability from neighboring LDCs and is not a long-term supply option.

5.1.3 Spot Gas Supplies

This option involves procuring additional delivered natural gas from spot markets during peak periods. This approach has been successful for small volumes in the past, but volumes are subject to capacity availability on the CIG system. Availability of this option is contingent upon CIG capacity availability and cannot be relied on for long-term planning purposes.

5.1.4 Build Air-Blend Capacity

Springs Utilities can build and operate an air blend facility, separate from CIG. The estimated cost of building an operating an air blend facility is substantially less than the proposed cost by CIG ($5/Mscf-Day). Additionally, a self-build option can provide capacity in increments smaller than the 15,000 Mscf/day minimum offered by CIG. A self-build facility is estimated to take 36 months to construct and may require interim supply resources until the facility is operational. A self-build air blending facility still requires transportation capacity to be available from CIG and only operates if the underlying capacity is available. Due to the capital costs and transportation requirements, this is considered less feasible than other supply solutions.

5.1.5 Expand Existing Propane Air Plant

Springs Utilities existing propane air plant can be expanded to deliver an incremental 300 Mscf per hour in addition to the current, but not yet proven, 1,800 Mscf per hour design rating. The expanded capacity would be accomplished through the addition of new air compressors. The existing facility was designed and permitted to expand to 2,400 Dth per hour in year 2018 but may be limited to 2,100 Dth per hour due to blending limitations. The PAP can serve both peak-hour and peak-day supply requirements and is best suited to meet occasional load demands. The PAP's variable cost per unit of production is higher than natural gas market prices but the annual carrying costs are lower compared to firm transportation reservation costs on CIG.

5.1.6 Build New Propane Air Plant

A new PAP could be built to provide an additional 650 Dth per hour (15,600 Dth per day) of capacity and would allow for future expansion should natural gas usage continue to grow as expected. This option would require 20 to 40 acres of land, much of it providing a buffer from surrounding properties. Traffic to and from the site would be expected to be minimal, primarily consisting of transport trucks to deliver propane after a period of use. Springs Utilities employees performing maintenance and other work would be additional sources of traffic. The potential to co-locate with new electric generation will be explored. The total expected cost of a new PAP facility is estimated to be approximately $25 million including the cost of land acquisition. A new PAP facility is estimated to require 24 to 36 months to become operational, with construction lasting around 18 months.

5.1.7 Contract Additional Storage Capacity

Springs Utilities could acquire additional NNT capacity as a natural gas supply option. This would be a favorable supply alternative from an operational perspective. Additional NNT capacity is less economical than other alternatives for meeting peak-day and peak-hour supply requirements and is more expensive long-term than other supply alternatives.

5.1.8 Contract Additional Firm Transport Capacity

The CIG system is fully subscribed, and no additional firm transportation capacity is available. Additional firm capacity would have to be obtained via a CIG expansion project or acquired from a third party with excess capacity. A mainline CIG expansion project would include compression, air blending, possibly pipeline looping back to key mainline points. The planning and implementation period on this type of new construction is 24 to 36 months. This option would require a Springs Utilities commitment for CIG to pursue a pipeline expansion project and the associated capital recovery either in advance payment or through a rate dedicated to the expansion. This option is not financially attractive compared to other options.

5.1.9 Liquified Natural Gas Peaking Facility

Liquified Natural Gas ("LNG") plants are a readily available and salient response to short-term natural gas supply shortages. LNG plants are scalable with major features of the plant scalable for injection, withdrawal, and inventory requirements. Additionally, LNG plants can include capabilities to directly receive natural gas via pipelines, liquefy the gas, and store it. An alternative to on-site liquefaction is road delivery via trucks, avoiding the cost of building on-site liquefaction facilities. LNG withdrawal (send-out) capability can be sized at a high ratio compared to underground storage or propane air facilities. For example, it typically takes several weeks or months to completely withdrawal traditional underground storage facilities due to pressure limitations. An LNG facility can be configured to withdraw is entire inventory within a few days, so a small inventory can be maintained for a given level of short-term gas availability.

Building a new LNG facility will require extensive studies and major capital investment in the order of magnitude of $100 to $200 million. Partnering with CIG or other LDCs would likely be required to achieve economies of scale to improve the viability of the project. This option is not considered economically feasible compared to other supply alternatives.

6.0 DEMAND-SIDE MANAGEMENT

The CIG system is fully subscribed and increasing delivery capacity would require substantial capital expenditures to add compression and air injection facilities on the system. Those costs would ultimately be passed on to Springs Utilities customers via a supplemental CIG rate and contract to cover the expansion costs. New peak shaving facilities would also require large capital expenditures and a subsequent impact on customer rates. Demand-side management ("DSM") programs may provide a lower-cost alternative to supply side options and thus were analyzed as part of the 2020 GIRP.

The primary capacity constraint and cost impact Springs Utilities Gas System faces is meeting peak-hour natural gas demand. As outlined in balance of loads and resources (Section 4.3), Springs Utilities is expected to have a peak-hour supply deficit by the 2032-2033 heating season, whereas the system is expected to have adequate peak-day supply through the 2043-2044 heating season with an effective DSM program. DSM programs provide an opportunity to reduce the peak-hour gas consumption and could potentially defer or avoid the need for additional peak-hour supply resources. Springs Utilities contracted a DSM study through CADMUS in 2019 that identified potential gas and electric demand response ("DR") and energy efficiency ("EE") opportunities, along with associated cost and load reduction parameters.

DR programs for the peak-hour gas consumption are less mature than those in the electric industry. Because of this, potential DR programs and their impact to gas distribution systems is emerging. The 2020 GIRP DSM options were modeled at a conservative screening level to frame the potential impact with the understanding that additional work will be required to determine a feasible level of implementation, including pilot programs to measure customer acceptance and cost effectiveness. Concepts, data, and results from the analysis are included in the following sections.

6.1 DSM BACKGROUND AND CONCEPTS

DSM programs influence customers to reduce their energy consumption, change use patterns away from peak consumption periods, or reduce overall consumption. These programs typically include providing educational information, energy audits, and rebates to persuade customers to adopt sustainable conservation measures. DSM programs are targeted to benefit both the utility and its customers. Customers are motivated via monetary incentives such as tax breaks, a reduction in their natural consumption, rebates, or an enhancement in their comfort. Natural gas utilities also benefit from these programs by reducing peak-day and peak-hour demand. Additionally, lowering the peak-day and peak-hour natural gas demand can reduce the overall cost of natural gas service by preventing or deferring the need to add additional capacity on the CIG system or constructing new peak-shaving facilities.

Springs Utilities has offered small-scale natural gas DSM programs to its customers since 2001. In January 2003, the Utilities Board provided policy guidance through the “Ends-Environmental Results.” The policy provided direction on managing DSM and other renewable energy programs. To date, these programs resulted in multiple benefits including reducing customers’ bills, reducing the immediate need of supply-side resources, and reducing greenhouse gas emissions. In addition, the benefits made acquiring cost-effective DSM resources an attractive resource alternative to help minimize energy service costs while promoting environmental stewardship. Future DSM programs will seek to demonstrate the feasibility of increasing the financial resources dedicated to achieving cost-effective peak demand reductions.

DSM opportunities are generally categorized as DR or EE programs with associated impacts on energy consumption and peak demand. Some programs depend on behavioral adjustments by customers, while others may be built-in or controlled directly by Springs Utilities or third parties. For capacity planning purposes, Springs Utilities can only consider built-in or directly controlled resources as firm capacity.

6.1.1 Demand Response Opportunities

Demand response opportunities typically include measures that have a direct impact on shifting demand away from peak periods. DR programs would be voluntary and seek customers who are willing to commit to contracts that cede control of their gas-consuming equipment to Springs Utilities or third parties during peak demand periods. DR programs can have a large impact on shifting capacity away from peak periods but have minimal impacts on total energy consumption. DR programs typically must have outside control to be dependable for capacity planning purposes. A DR program example would be direct thermostat control of furnaces or water heaters. In concept the thermostat would be turned down 2 to 5 degrees for a 30 or 60-minute period during peak hours. Starting DR programs can be costly however, equipment can be relatively inexpensive and have short payback periods. Program initiation costs could potentially be shared with electric DR programs to leverage both gas and electric programs. Another potential DR opportunity would include pre-heating facilities so some customer's peak demand would be shifted to alternate hours of the day.

6.1.2 Energy Efficiency Opportunities

EE improvements tend to be built-in and reduce both demand and energy consumption. Another benefit of EE is an overall reduction in GHG emissions due to decreased energy consumption. EE programs that achieve year-round energy savings, independent of weather, are considered baseload measures. Examples of baseload measures include high-efficiency water heaters, cooking equipment, and front-load clothes washing machines. Measures that are influenced by weather conditions include higher efficiency furnaces, ceiling/wall/floor insulation, weather stripping, insulated windows, door thresholds, duct work improvements, and ventilation heat recovery systems. Weather-sensitive measures are desirable in gas supply planning as they reduce peak-day and peak-hour demand. Building envelope improvements additionally would allow for potential electrification initiatives long-term. Overall, EE improvements reduce both demand and energy consumptions. Except for air infiltration measures, EE measures tend to be costly and have longer payback periods than DR programs. EE programs additionally tend to require more resources to implement and manage than DR programs.

6.2 STUDY APPROACH

Springs Utilities commissioned a third-party consultant to perform a DSM study to determine the potential amount of energy and demand reduction that could be reasonably accomplished through Springs Utilities service territory. The following study builds on previous DSM efforts by Springs Utilities and seeks to develop reasonable estimates of the magnitude, costs, and timing of resources available over the study period. The DSM study does not provide guidance on how or by what means identified programs might be acquired. For example, potential for appliance efficiency standards or building shell measures may be attained through utility incentives, legislative action, or other socio-economic measures. The methods used to evaluate the technical and achievable potential drew upon standard utility industry practices.

6.2.1 Data Collection

The data needed for DSM program evaluation was acquired through multiple sources summarized in Table 6-1.

Table 6-1: DSM Data Sources

Data item	Residential source	Non-Residential (C&I) source
Baseline Sales and Customers	Springs Utilities customer count and usage history	Springs Utilities customer count and usage history
Forecasted Sales and Customers	Springs Utilities	Springs Utilities
Percentage of Sales by Building Type	County Assessor's data	Springs Utilities Non-residential customer database
End-Use Energy Consumption	Springs' Utilities Load Forecasts, 2015 Primary Research, EIA Residential Energy Consumption Survey (RECS), ENERGY STAR, XCEL (CO) TRM	Springs' Utilities Load Forecasts, 2015 Primary Research, EIA Commercial Building Energy Consumption Survey (CBECS), EIA Manufacturing Energy Consumption Survey (MECS), ENERGY STAR, XCEL (CO) TRM
Saturations & Fuel Shares	2015 Primary Data Collection Phone Surveys, EIA RECS	2015 Primary Data Collection Phone Survey and Site Visit, EIA's CBECS and MECS
Efficiency Shares	2015 Primary Data Collection Phone Survey and Site Visit EIA's RECS, ENERGY STAR unit shipment reports	2015 Primary Data Collection Phone Survey and Site Visit, EIA's CBECS and MECS

6.3 DEMAND RESPONSE

Demand response programs strive to reduce peak demand during system emergencies or periods of natural gas supply constraints. The analysis focused on DR options that included residential and non-residential direct load control ("DLC") and non-residential load curtailment for Springs Utilities natural gas customers. These DR strategies included price and incentive-based options for all major customers within Springs Utilities service territory. The study applied a hybrid, top-down, and bottom-up approach to estimate DR potentials, beginning by using Springs Utilities' system loads disaggregated into sectors, segments, and applicable end uses. For each program, the potential impacts at the end-use level were investigated and aggregated to obtain estimates of technical potential. The study approach allowed Springs Utilities to apply market factors (such as likely program participation) to each program's technical potential and develop estimates for market adoption. Various DR options evaluated in Springs Utilities service territory are as follows:

6.3.1 Option 1: Residential Smart Thermostat – Direct Installation

During peak events, Springs Utilities controls participating, residential, gas central heating loads by changing setpoints on smart thermostats. This study assumed winter peak events occur in winter mornings, lasting up to three hours, with up to 10 events per heating season. Customers eligible for participation in this program must have gas central heating equipment and do not currently have a smart thermostat. Table 6-2 includes the assumptions used to estimate technical potential and levelized costs for this program.

Table 6-2: Residential DLC Smart Thermostat Direct Install Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program
O&M Cost	$ per participant per year	$20	Aligned with its electric counterpart
Equipment Cost	$ per new participant	$250	Aligned with its electric counterpart
Marketing Cost	$ per new participant	$25	Aligned with its electric counterpart
Incentives (annual)	$ per participant per year	$25	SoCalGas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$0	There is no one-time incentive, unlike the BYOT option.
Attrition	% of existing participants per year	1.50%	Aligned with its electric counterpart
Eligibility	% of customer count (e.g., equipment saturation)	Varies by Segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	Southern California Gas pilot (2018): 16% to 25% for a morning event
	% of peak-day load	2%	Southern California Gas pilot (2018): 2.3% to 2.5% of peak day impact for a morning event (neither were statistically significant).
Program Participation	% of eligible customers	15%	Southern California Gas (Hanway 2019): 16% participation of eligible Ecobee thermostats.
Event Participation	%	100%	Peak load impact already accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with its electric counterpart

The analysis determined the Residential DLC Smart Thermostat Direct Install program could provide 105 Dth of winter peak-hour reduction by 2039, at a levelized cost of $978 per therm-year. The program could provide up to 206 Dth of peak-day reduction (assuming a three-hour morning event) at a levelized cost of $499 per therm-year.

6.3.2 Option 2: Residential Smart Thermostat – Bring-your-own-thermostat

The Residential DLC Smart Thermostat Bring-your-own-thermostat ("BYOT") is identical to the Residential DLC Smart Thermostat Direct Install program, except that it requires the participants to already have installed a smart thermostat. Thus, the potential study assumes no equipment or installation costs for smart thermostats, but pays participants a $50, one-time incentive in addition to the $25 annual incentive. This study assumed winter peak events occur in winter mornings, lasting up to three hours, with up to 10 events per heating season. Customers eligible for participation in this program must have gas central heating equipment and an installed smart thermostat. Table 6-3 includes the assumptions used to estimate technical potential and levelized costs for this program.

Table 6-3: Residential DLC Smart Thermostat BYOT Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program
O&M Cost	$ per participant per year	$20	Aligned with its electric counterpart
Equipment Cost	$ per new participant	$0	Aligned with its electric counterpart
Marketing Cost	$ per new participant	$25	Aligned with its electric counterpart
Incentives (annual)	$ per participant per year	$25	SoCalGas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$50	Southern California Gas (Hanway 2019): Assumed a one-time $50 incentive.
Attrition	% of existing participants per year	1.50%	Aligned with its electric counterpart
Eligibility	% of customer count (e.g., equipment saturation)	Varies by Segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	Southern California Gas pilot (2018): 16% to 25% for a morning event
	% of peak-day load	2%	Southern California Gas pilot (2018): 2.3% to 2.5% of peak day impact for a morning event (neither were statistically significant).
Program Participation	% of eligible customers	15%	Southern California Gas (Hanway 2019): 16% participation of eligible Ecobee thermostats.
Event Participation	%	100%	Peak load impact already accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with its electric counterpart

The analysis determined the Residential DLC Smart Thermostat BYOT program could provide 114 Dth of winter peak-hour reduction by 2039, at a levelized cost of $803 per therm-year. The program could provide up to 224 Dth of peak-day reduction (assuming a three-hour morning event) at a levelized cost of $409 per therm-year. Both in terms of peak-hour and peak-day impacts, this option can provide slightly more DR potential at a lower cost than the Direct Install program. Regardless, both options could be implemented simultaneously.

6.3.3 Option 3: Residential Water Heater Direct Load Control

The Residential Water Heater DLC program retrofits existing gas storage water heaters by installing a water heater controller. Using the controller, Springs Utilities can remotely control participating residential water heating loads. This study assumed that winter peak events occurred in winter mornings, lasting up to three hours, for up to 10 events per heating season. Customers eligible for participation in this program must have gas storage water heaters to participate. The Aquanta controller assumed in this study can only be installed on gas storage water heaters with electronic ignition, and this retraction is reflected in the program participation rate. Table 6-4 includes the assumptions used to estimate technical potential and levelized costs for this program.

Table 6-4: Residential DLC Water Heater Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program
O&M Cost	$ per participant per year	$20	Aligned with other residential gas DLC products.
Equipment Cost	$ per new participant	$300	Aquanta water heater controller cost: $150 (2019). Consolidated Edison (2017) assumed total installed cost: $300.
Marketing Cost	$ per new participant	$25	Aligned with other residential gas DLC products.
Incentives (annual)	$ per participant per year	$25	SoCalGas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$0	This study assumes no one-time incentive.
Attrition	% of existing participants per year	1.50%	Aligned with other residential gas DLC products.
Eligibility	% of customer count (e.g., equipment saturation)	Varies by Segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	This study assumes similar impact as other residential gas DLC products.
	% of peak-day load	5%	Consolidated Edison (2017) conservative assumption for annual savings, assumed for peak-day savings.
Program Participation	% of eligible customers	15%	Aligned with other residential gas DLC products. Given the Aquanta controller specification, this study assumes that only gas storage water heaters with electronic ignition participate.
Event Participation	%	100%	Peak load impact already considers event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with other residential gas DLC products.

The analysis determined the Residential DLC Water Heater program could provide 92 Dth of winter peak-hour reduction by 2039, at a levelized cost of $2,883 per therm-year. The program could provide up to 546 Dth of peak-day reduction (assuming a three-hour morning event) at a levelized cost of $525 per therm-year.

6.3.4 Option 4: Residential Critical Peak Pricing Opt-In

Under Residential Critical Peak Pricing ("CPP") Opt-In, customers voluntarily opt-in to receive a discount on their normal retail rates during non-critical peak periods in exchange for paying predetermined, premium prices during critical peak events. The basic rate structure is a time of use ("TOU") tariff, with the rate using fixed pricing during different time periods. Typically, on-peak, off-peak, and mid-peak prices by season are the time periods in TOU tariffs. This study assumes that Springs Utilities may call critical peak events lasting four hours for up to 10 events during the winter heating season. During these events, the normal peak price under a TOU rate structure is increased to a significantly higher price to incentivize participants to shift energy use outside of the event period. All residential gas customers are eligible for this program, assuming full advanced metering infrastructure ("AMI") deployment for Springs Utilities residential customers by the end of 2023. Table 6-5 includes the assumptions used to estimate technical potential and levelized costs for this program.

Table 6-5: Residential Critical Peak Pricing Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program
O&M Cost	$ per participant per year	$50,000	Aligned with residential electric CPP product.
Equipment Cost	$ per new participant	$0	Colorado Springs assumes that AMI will be fully deployed by the end of 2023.
Marketing Cost	$ per new participant	$25	Aligned with residential electric CPP product.
Incentives (annual)	$ per participant per year	$0	Aligned with residential electric CPP product.
Incentives (one time)	$ per new participant	$0	Aligned with residential electric CPP product.
Attrition	% of existing participants per year	10.00%	Aligned with residential electric CPP product.
Eligibility	% of customer count (e.g., equipment saturation)	100.00%	Aligned with residential electric CPP product.
Peak Load Impact	% of peak-hour load	20%	Aligned with residential electric CPP product.
	% of peak-day load	4%	Aligned with residential electric CPP product. Assumes a three-hour morning event, normalized to peak-day impact.
Program Participation	% of eligible customers	15%	Aligned with residential electric CPP product.
Event Participation	%	100%	Aligned with residential electric CPP product.
Ramp Period	Number of years to reach maximum achievable potential	10	Aligned with residential electric CPP product.

The analysis determined the Residential CPP program could provide 293 Dth of winter peak-hour reduction by 2039, at a levelized cost of $95 per therm-year. The program could provide up to 1,204 Dth of peak-day reduction (assuming a three-hour morning event) at a levelized cost of $23 per therm-year. Note that participants in this program potentially overlap with participants in other residential gas DLC products (especially smart thermostat programs). Therefore, this product may resemble a lower-cost approach to incentivizing customers to reduce gas demand during peak winter periods.

6.3.5 Option 5: Commercial Smart Thermostat – Bring-your-own-thermostat

Commercial customers receive incentives to allow Springs Utilities to control their gas central heating equipment during winter peak events. This study assumed winter peak events occur in winter mornings, lasting up to three hours, with up to 10 events per heating season. Participants receive an annual incentive of $25 per therm committed to curtailment, in addition to a one-time incentive of $85 upon program enrollment. Customers eligible for participation in this program must have gas central heating equipment and an installed smart thermostat. Table 6-6 includes the assumptions used to estimate technical potential and levelized costs for this program.

Table 6-6: Commercial DLC Smart Thermostat BYOT Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program
O&M Cost	$ per participant per year	$75	Estimate based on Southern California Gas program plan (Hanway 2019) for residential and commercial programs combined, less annual incentives.
Equipment Cost	$ per new participant	$0	This study assumes the participant already has a smart thermostat.
Marketing Cost	$ per new participant	$0	Included in O&M cost
Incentives (annual)	$ per participant per year	$25	National Grid pilot in New York for large boilers: $30/therm (Roth 2019); Southern California Gas program plan (Hanway 2019): $10/therm for core customers.
Incentives (one time)	$ per new participant	$85	Consolidated Edison (2018): $85; Southern California Gas program plan (Hanway 2019): $90.
Attrition	% of existing participants per year	5.00%	National grid pilot in New York (Roth 2019): 6%
Eligibility	% of customer count (e.g., equipment saturation)	Varies by Segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	50%	National Grid pilot in New York (Roth 2019) for large boilers.
	% of peak-day load	8%	National Grid pilot in New York (Roth 2019) for large boilers for a three-hour event: 50%, normalized to peak-day impact, assuming no rebound effect
Program Participation	% of eligible customers	2.5%	National Grid pilot in New York (Roth 2019) for large boilers.
Event Participation	%	100%	Peak load impact already considers event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with residential gas DLC products.

The analysis determined the Commercial DLC Smart Thermostat BYOT program could provide 25 Dth of winter peak-hour reduction by 2039, at a levelized cost of $274 per therm-year. The program could provide up to 81 Dth of peak-day reduction (assuming a three-hour morning event) at a levelized cost of $84 per therm-year. Compared to the residential options, this program provides a small amount of potential savings.

6.4 ENERGY EFFICIENCY

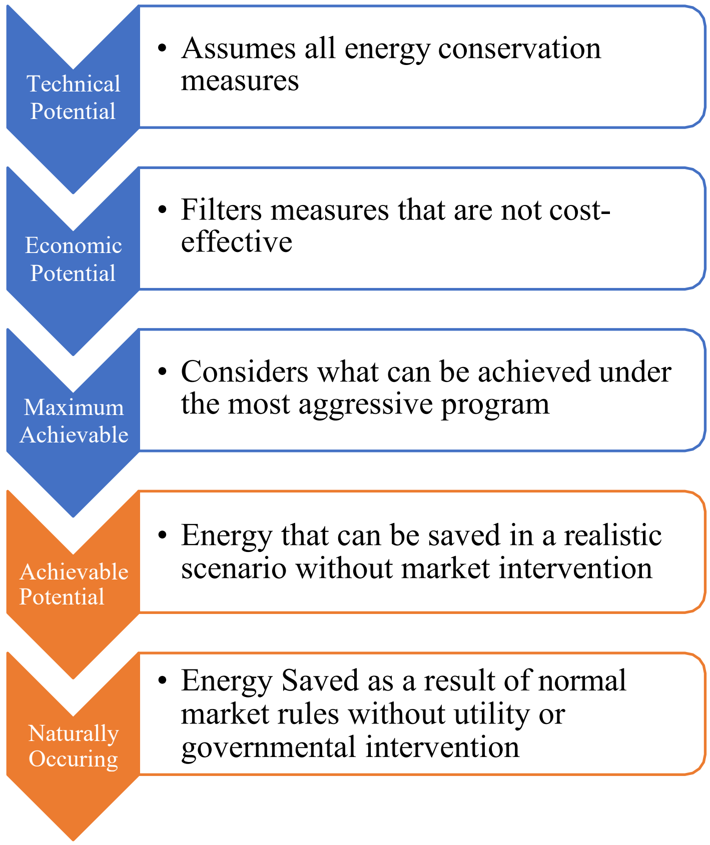
The energy efficiency analysis consisted of assessing over 300 unique gas EE measures. Data was gathered from Springs Utilities existing program data, Xcel Energy's (CO) 2019-2020 Demand-Side Management Plan, and other databases to determine savings, costs, and applicability for each measure. The study prepared a peak demand and energy consumption estimate for the period 2020 through 2038. Each EE program considered was assigned a life span of approximately ten years after which no further savings were possible from that particular program. This assumption was used as the forecast was extended from 2038 through 2050. Since EE savings potential declines over time as the effects of various programs decline, the total annual savings from EE also decline beyond 2038.

The approach used for estimating the EE proposals drew upon standard industry practices and proved consistent with potentials identified in Springs Utilities 2016 Demand-Side Management Potential Assessment. Typical metrics used when evaluating EE programs include:

- **Naturally Occurring Potential:** Energy saved as the results of normal market forces, that is, in the absence of any utility or governmental intervention.
- **Technical Potential:** Assumes the complete penetration of all energy-conservation measures that are considered technically feasible from an engineering perspective.
- **Economic Potential:** The technical potential of measures that are cost-effective when compared to supply-side alternatives. The economic potential tends to be very large because it is summing up the potential from existing equipment, without accounting for the period during with the potential would be realized.
- **Maximum Achievable Potential:** The economic potential that could be achieved over a given period under the most aggressive program scenario.
- **Achievable Potential:** The energy saved as a result of specific program funding levels and incentives. These savings are above and beyond the naturally occurring potential.

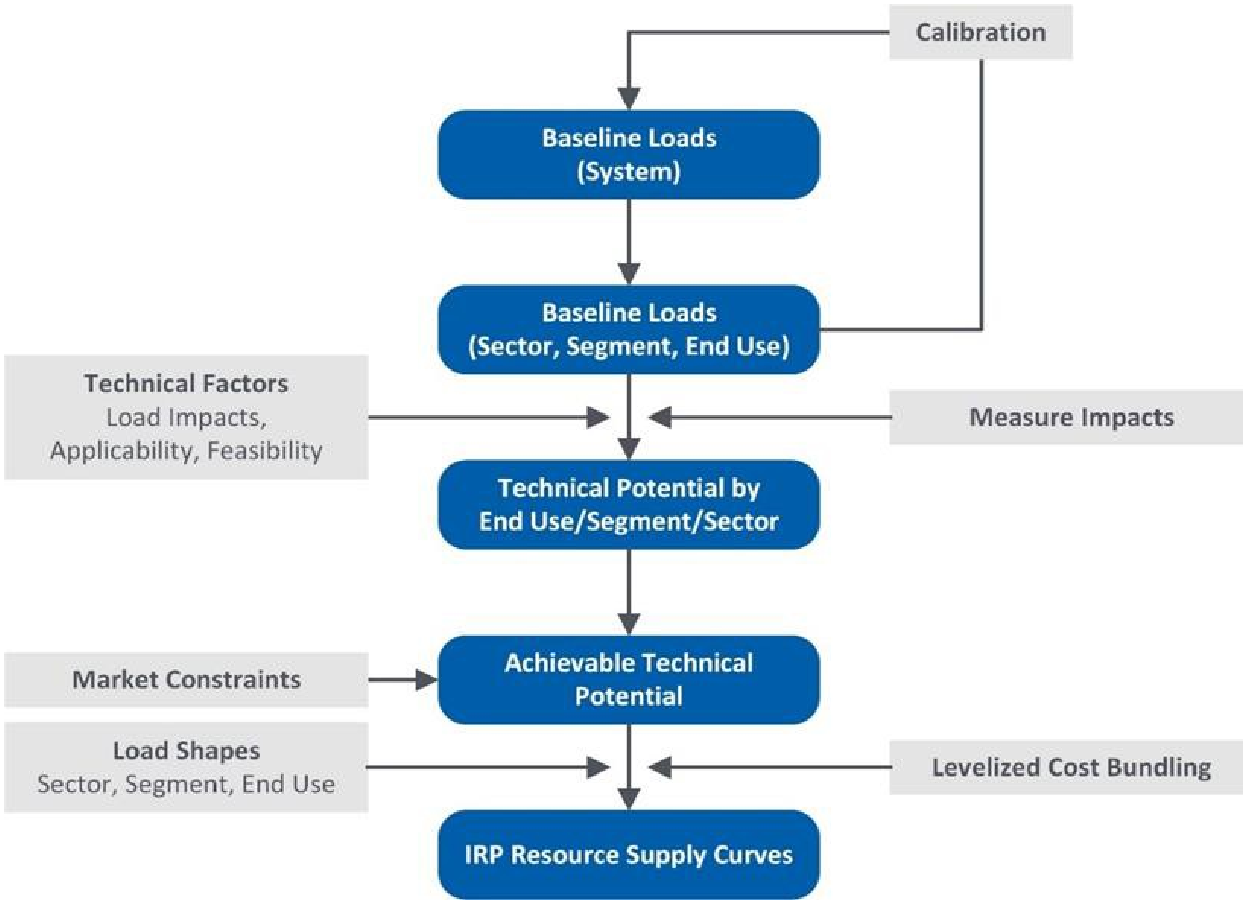
Figure 6-1 includes an illustration of the different types of potential used in evaluating EE programs.

Figure 6-1: Energy Efficiency Program Potentials



This study considered three types of EE potential listed above: naturally occurring, technical, and achievable potential. The assessment accounted for gradual efficiency increases due to the replacement of older equipment and subsequent new equipment meeting minimum efficiency standards at that time. For some end uses, the technical potential associated with certain energy-efficient measures were developed assuming a natural adoption rate. For example, savings associated with ENERGY STAR appliances accounted for current trends in customer adoption. It also accounts for the energy consumption characteristics of new construction complying with current building codes. The assessment also accounted for improvements in pending equipment efficiency standards that will take effect during the planning horizon. However, the evaluation did not forecast changes to standards that have not yet been passed; rather, it treated those as "frozen" at the existing efficiency level. These impacts resulted in baseline sales, from which technical and achievable potential were estimated. Figure 6-2 illustrates the methodology used for the EE study.

Figure 6-2: Energy Efficiency Evaluation Methodology



Technical potential can be further broken down into discretionary (retrofits) and lost opportunities (new construction and replacement of existing equipment). The study's technical potential estimations for EE resources drew upon best-practice research methods and typical utility industry analytic techniques. Such techniques remained consistent with other planning entities' conceptual approaches as well as the methods used in Springs Utilities' 2016 DSM Potential Study. The achievable technical potential represents the portion of technical potential that could be reasonably achieved over the 20-year planning period. Accordingly, the possibility that market barriers could impede customer adoption was factored into the analysis. Program cost-effectiveness was not considered during this portion of the evaluation, and the achievable technical potential was identified to principally serve as planning guidelines and informational sources for the GIRP process. Figure 6-3 summarizes the cumulative potential energy saved by EE programs over the study horizon.

6.4.1 Residential Sector

By 2039, residential customers are forecasted to account for 60 percent of Springs Utilities natural gas sales. Unlike residential electricity consumption, natural gas consumption is limited to few end-uses.

Residential natural gas consumption is primarily used for space heating, water heating, and certain appliances such as dryers and stove tops. Even with the limited end uses, significant energy-saving opportunities remain. Based on the energy efficiency measures used in this analysis, achievable technical potential in the residential sector could provide up to 27 million therms by 2039, corresponding to a 17 percent reduction in forecasted residential sales. Single-family homes account for 80 percent of the identified achievable technical potential, and multi-family residences account for the remaining 20 percent.

Figure 6-3 shows the cumulative achievable technical potential for natural gas consumption by end use. Space heating and water heating account for 99 percent of identified potential.

Figure 6-3: Residential Gas EE Potential by End Use

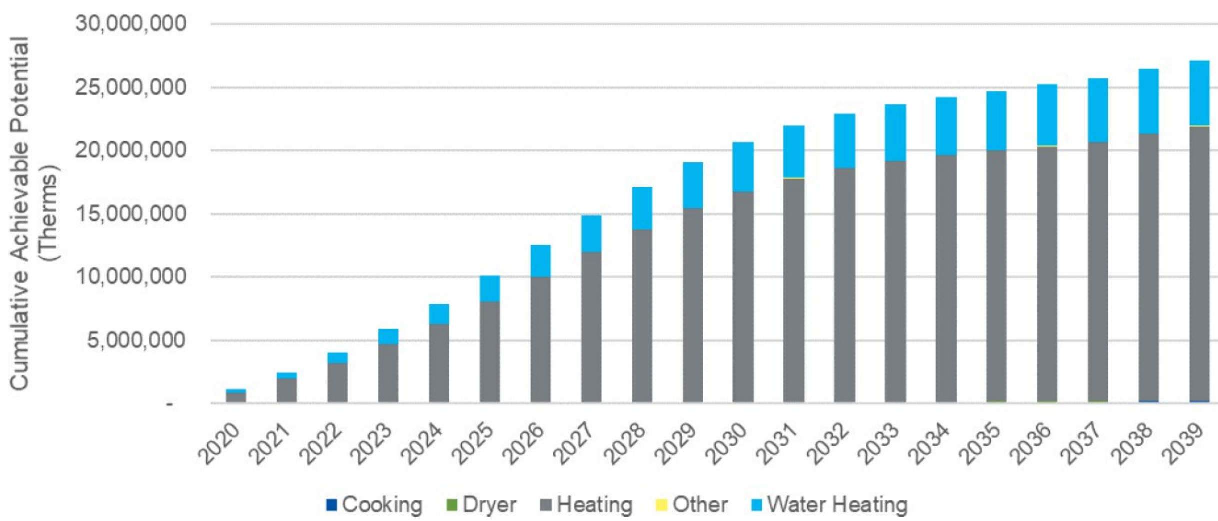


Table 6-7 includes the top 15 residential energy efficiency measures ranked in order of cumulative, 20-year, achievable technical potential. Combined, these 15 measures account for 22 million therms, or approximately 82% of the identified achievable technical potential.

Table 6-7: Top Residential Gas EE Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Furnace - ENERGY STAR 2019 Most Efficient	$5.60	856,810	2,512,883
Air Sealing	$3.17	2,594,891	3,125,065
Ceiling / Attic Insulation	$3.05	2,359,485	2,877,650
Combination Gas Space and Water Heat	$1.10	1,567,671	2,071,613

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Furnace - Maintenance	$0.49	900,820	1,801,640
Indirect Energy Feedback	$0.79	1,485,800	1,607,857
Air-to-Air Heat Exchangers	$2.71	994,029	1,459,432
Floor Insulation	$1.80	942,159	1,161,243
Furnace - Quality Install	$1.04	512,366	1,044,415
Learning Wi-fi Thermostat	$1.83	672,239	937,487
Showerhead Low Flow	$0.04	767,491	869,114
Wall Insulation - 2x6	$2.56	543,616	759,888
Duct Sealing and Insulation Combined	$1.11	629,157	757,703
Windows - Storm - ENERGY STAR	$1.00	514,887	620,086
Windows	$5.43	496,562	619,122

6.4.2 Commercial Sector

Based on the energy efficiency measures used in this analysis, achievable technical potential in the commercial sector could provide up to 16.4 million therms by 2039, corresponding to a 22 percent reduction in forecasted commercial sales. As shown in Figure 6-4, office buildings represent 20 percent of potential savings, followed by other commercial facilities (17 percent), lodging (13 percent), and education (11 percent).

Figure 6-4: Commercial Gas EE Potential by Segment

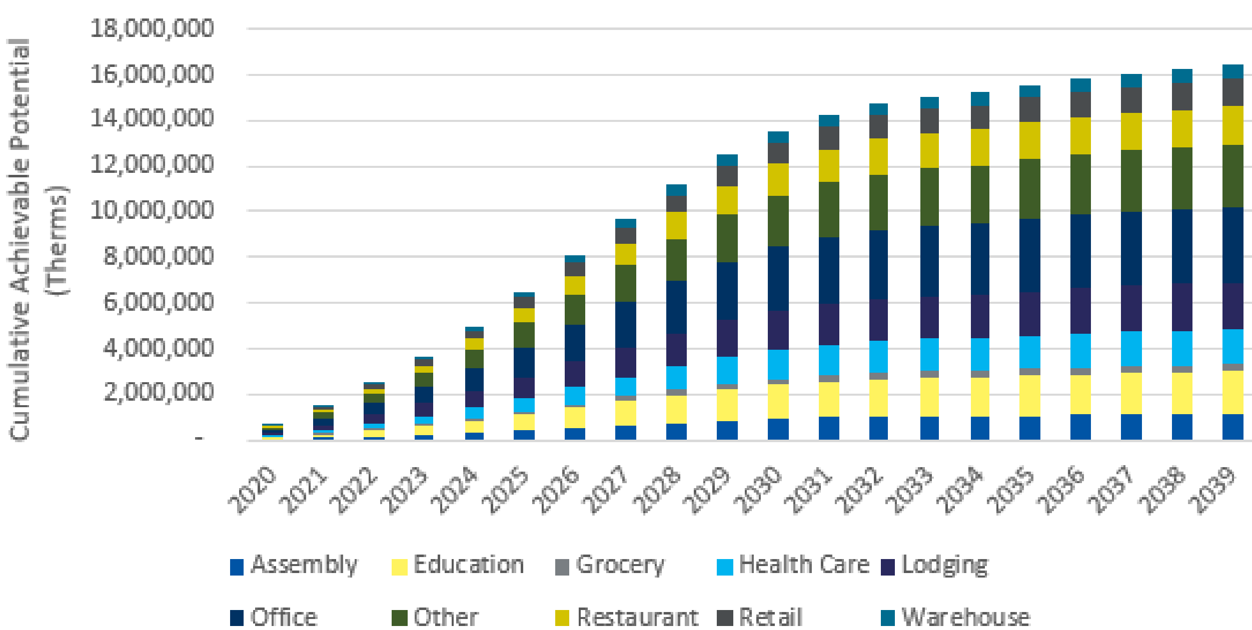


Figure 6-5 shows the cumulative achievable technical potential for natural gas consumption by end use. As in the residential sector, natural gas consumption is limited to few end usages. Space heating (e.g., HVAC equipment upgrades, shell improvements) accounts for 72 percent of identified achievable technical potential. The remaining potential consists of water heating (20 percent), cooking (7 percent), and other end uses.

Figure 6-5: Commercial Gas EE Potential by End Use

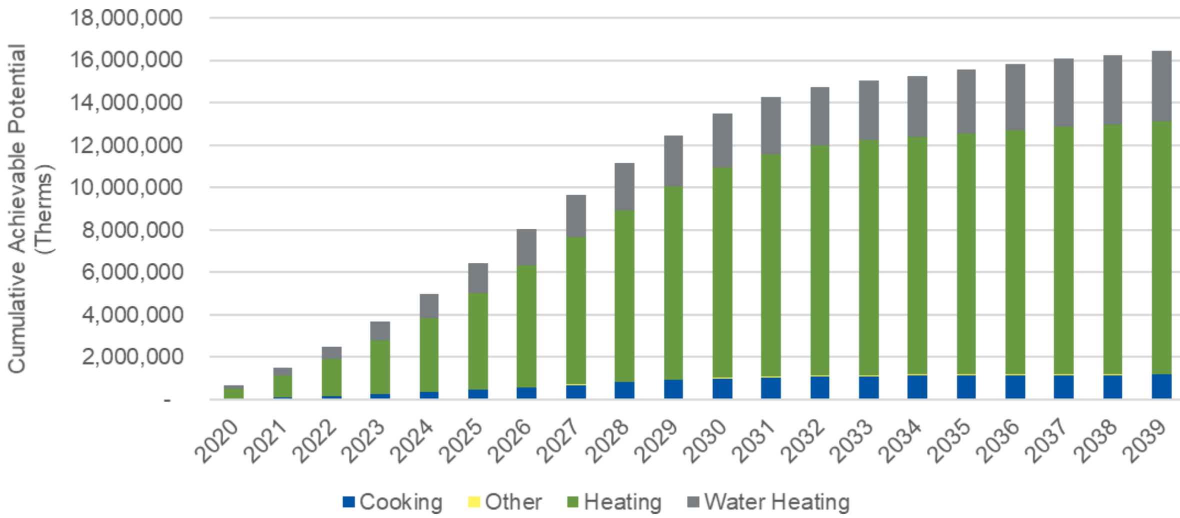


Table 6-8 includes the top 15 commercial energy efficiency measures ranked in order of cumulative, 20-year, achievable technical potential. Combined, these 15 measures account for 11.3 million therms, or approximately 69 percent of the identified achievable technical potential. Of the top 15 measures, most (over 10) are related to reducing commercial gas consumption related to space heating.

Table 6-8: Top Commercial Gas EE Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Retro commissioning	$1.25	2,394,135	2,883,292
Combination Gas Space and Water Heat	$1.30	1,378,401	1,756,117
Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	$1.21	691,610	832,916
Convert Constant Volume Air System to VAV	$5.17	669,705	806,536
Direct Digital Control System-Installation	$0.85	569,992	686,450
Wi-fi Thermostat	$0.38	524,464	651,491
Solar Hot Water (SHW)	$6.92	157,312	566,376
Furnace < 225k Btuh - ENERGY STAR 2019 Most Efficient	$6.27	137,693	475,387
Re-Commissioning	$1.22	390,386	470,147
Windows-High Efficiency	$30.21	362,759	450,565
Insulation - Ceiling	$10.75	357,284	440,852
Strategic Energy Management (SEM)	$0.60	285,158	355,746
Exhaust Air to Ventilation Air Heat Recovery	$6.48	259,329	333,053
Low-Flow Faucet Aerators (Private Use)	$0.04	297,062	312,806
Broiler	$0.41	245,541	312,232

6.4.3 Industrial Sector

Based on the energy efficiency measures used in this analysis, achievable technical potential in the industrial sector could provide a cumulative reduction of 2.4 million therms by 2039. Although this represents 20 percent of forecasted industrial sales, it accounts for only 6 percent of achievable technical potential across all customer segments. As shown in Figure 6-6 electrical equipment manufacturing represents 28 percent of potential savings, followed by miscellaneous manufacturing (18 percent), nonmetallic mineral products (14 percent), fabricated metal products (13 percent), and food manufacturing (11 percent).

Figure 6-6: Industrial Gas EE Potential by Segment

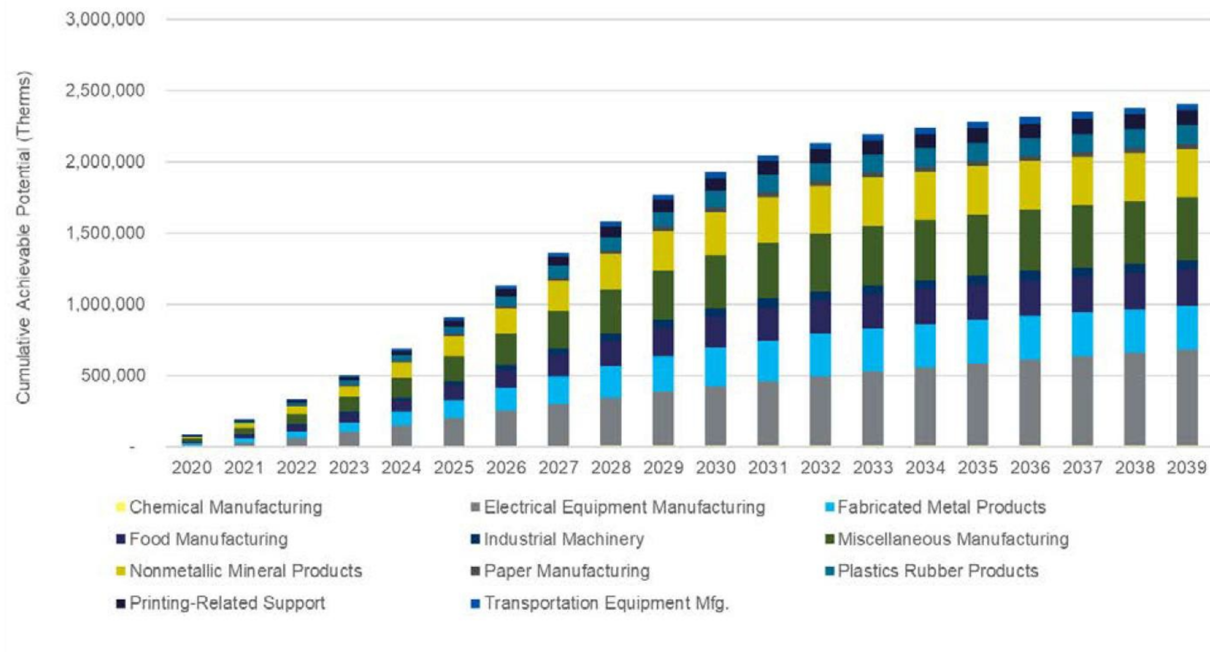


Figure 6-7 shows the cumulative achievable technical potential for natural gas consumption by end use. Indirect boiler (43 percent), process improvements (39 percent), and HVAC (17 percent) end uses account for all the identified achievable technical potential.

Figure 6-7: Industrial Gas EE Potential by End Use

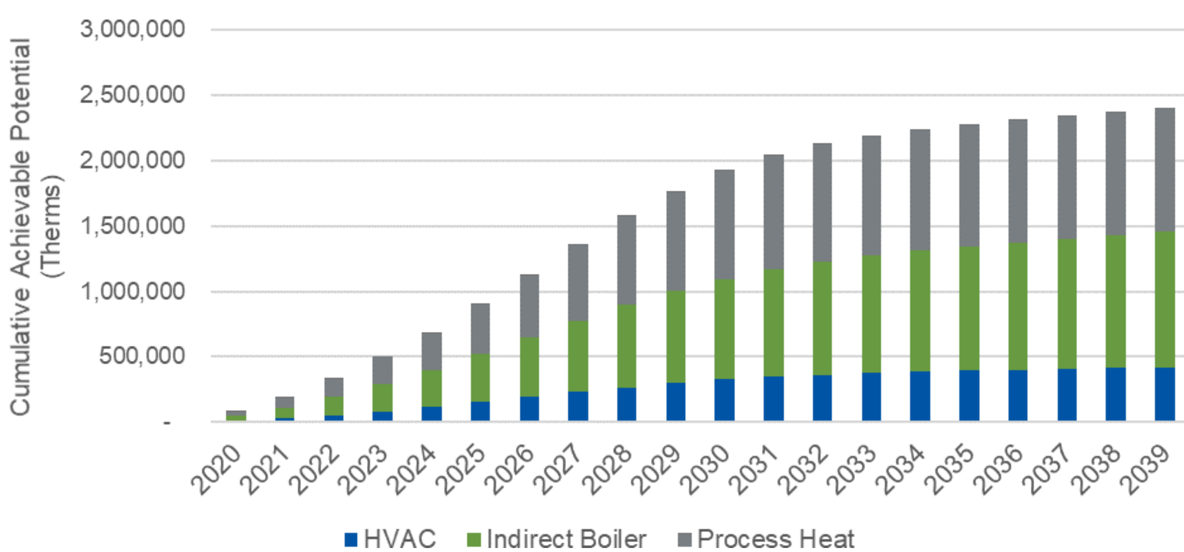


Table 6-9 includes the top 15 industrial energy efficiency measures ranked in order of cumulative, 20-year, achievable technical potential. Combined, these 15 measures account for 2.2 million therms, or approximately 92 percent of the identified achievable technical potential.

Table 6-9: Top Industrial Gas EE Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Waste Heat from Hot Flue Gases to Preheat	$0.13	282,580	351,164
Heat Recovery and Waste Heat for Process	$0.10	237,353	293,935
Isolate and Prevent Infiltration of Heat Loss from Equipment	$0.07	199,438	247,545
Optimize Heating System to Improve Burner Efficiency, Reduce Energy Requirements and Heat Treatment Process	$0.06	130,661	181,929
Analyze Flue Gas for Proper Air/Fuel Ratio	$0.10	117,373	164,278
Improve Combustion Control Capability and Air Flow	$0.07	115,647	161,266
Equipment Upgrade - Boiler Replacement	$1.20	63,485	121,045
Repair or Replace Steam Traps	$0.05	78,944	110,475
Optimize Ventilation System	$0.21	69,822	98,559
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers or Thermostats	$0.03	64,176	90,590
Building Envelope Insulation Improvements	$0.24	63,456	89,574
Boiler - Operation, Maintenance, and Scheduling	$0.12	45,105	86,483
Repair and Eliminate Steam Leaks	$0.04	56,629	78,109
Building Envelope Infiltration Improvements	$0.07	51,412	72,572
Equipment Upgrade - Replace Existing HVAC Unit with High Efficiency Model	$1.14	49,815	70,297

6.4.4 Military Sector

Based on the energy efficiency measures used in this analysis, achievable technical potential in the military sector could provide a cumulative reduction of almost 3.5 million therms by 2039. CADMUS estimated achievable technical potential for military natural gas consumption by the 11 commercial segments included in Figure 6-8. The non-classified uses (the other category) account for 32 percent of the 20-year technical potential, followed by offices (22 percent), lodging (11 percent), and health care (9 percent).

Figure 6-8: Military Gas EE Potential by Segment

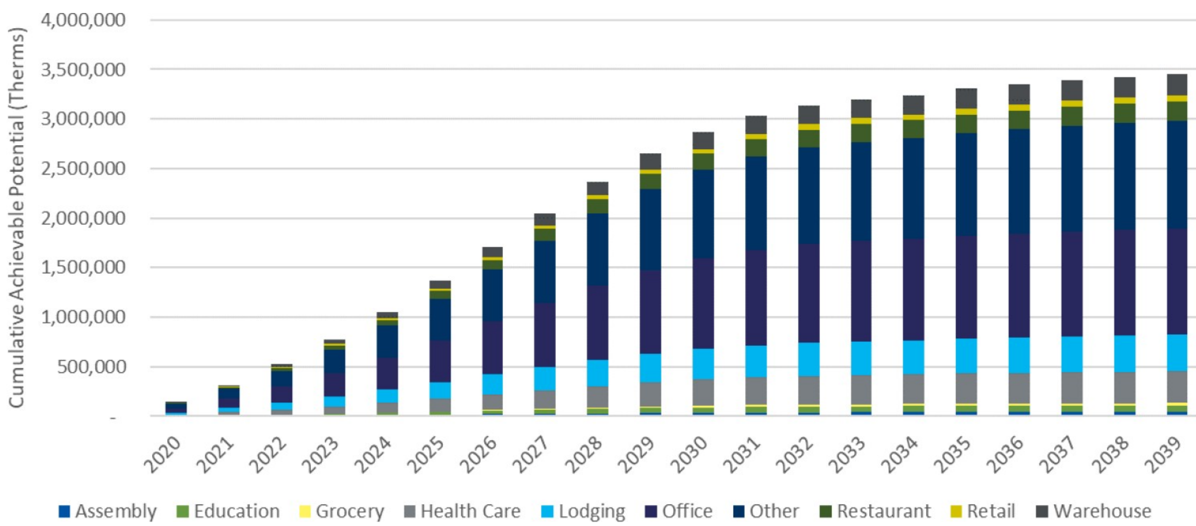


Figure 6-9 shows the cumulative achievable technical potential for natural gas consumption by end use. Similar to the commercial sector, space heating provides the greatest achievable technical potential, accounting for 79 percent of identified potential. The remaining potential is split among water heating (17 percent), cooking (4 percent), and other uses.

Figure 6-9: Military Gas EE Potential by End Use

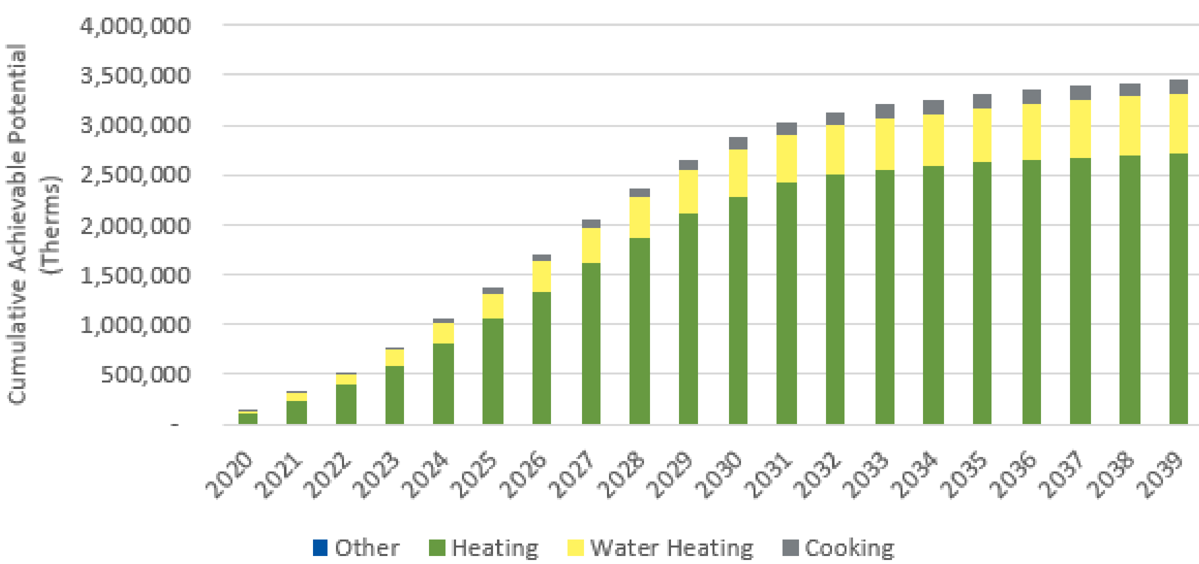


Table 6-10 includes the top 15 industrial energy efficiency measures ranked in order of cumulative, 20-year, achievable technical potential. Combined, these 15 measures account for 2.5 million therms, or approximately 73 percent of the identified achievable technical potential.

Table 6-10: Top Military Gas EE Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Retro-commissioning	$1.22	515,840	621,233
Combination Gas Space and Water Heat	$1.21	261,873	323,455
Automated Ventilation VFD Control (Occupancy Sensors/ CO2 Sensors)	$1.45	194,026	233,669
Direct Digital Control System - Installation	$1.21	164,816	198,490
Convert Constant Volume Air System to VAV	$4.66	149,582	180,144
Wi-fi Thermostat	$0.59	108,131	135,110
Re-Commissioning	$1.19	90,197	108,626
Furnace < 225 kBtuh - ENERGY STAR 2019 Most Efficient	$2.81	31,003	106,258
Solar Hot Water (SHW)	$8.13	29,845	103,424
Strategic Energy Management (SEM)	$0.62	83,184	101,556
Insulation - Ceiling	$10.53	81,421	99,466
Windows-High Efficiency	$31.91	76,051	93,116
Exhaust Air to Ventilation Air Heat Recovery	$5.72	58,702	77,355
Infiltration Reduction	$0.30	61,199	73,703
Duct Repair and Sealing	$1.86	57,074	68,735

6.5 PROGRAM EVALUATION

6.5.1 Cost Considerations

Cost competitiveness is a fundamental concept when evaluating DSM programs. In simple terms, cost-effectiveness is the determination of whether the present value of the capacity and energy savings (net of non-energy benefits) for any given conservation measure is greater than the cost to achieve the savings. Springs Utilities also considers parameters such as resource constraints, customer satisfactions, environmental issues, and regulatory issues. Programs were initially chosen based on the primary objective of reducing peak hourly load. Table 6-11 indicates the factors and approach used to review and select DSM programs that would provide benefits to customers.

Table 6-11: Demand-Side Management Program Assessment Methods

Test	Acronym	Key Questions Answered	Summary Approach
Participant Cost Test	PCT	Will participants be better off?	Comparison of costs and benefits to the participant
Utility Cost Test (Program Administrator Cost Test)	UCT	Will the total bills of energy services decrease?	Comparison of utility costs to supply-side resource costs
Total Resource Cost Test	TRC	Will the total resource costs (utility + participants) of energy services in the utility's service territory decrease?	Comparison of utility costs and participant costs to supply-side resource costs
Ratepayer Impact Measure Test	RIM	Will the utility rates decrease? (Impacts of program costs and lost revenues on general ratepayers)	Comparison of utility costs and utility bill reduction (revenue lost) to supply-side resource costs

To protect both customer and ratepayer interests, Springs Utilities will work to achieve a portfolio of DSM measures that pass the Total Resource Cost ("TRC") test. The TRC test is an economic screen that narrows DSM program options to those that are economically viable. Because customers may need to partner with Springs Utilities by investing private capital in DSM measures, customer acceptance and participation may limit the quantity of achievable DSM potential.

6.5.2 Demand Response Evaluation

The study developed a forecast of potential peak-day and peak-hour demand savings through DR programs. The DR savings were calculated for 2020 through 2039. Beyond 2039, the annual savings from DR programs were kept constant at 2039 levels.

Table 6-12 presents each gas DR product's achievable potential for peak-hour demand reduction and the associated dollar-per-term levelized cost. The two residential DLC smart thermostat products provide 219 dekatherms of achievable peak-hour potential. Residential Gas CPP is an alternative means of achieving similar reductions, but at a much lower levelized cost. Unlike electric Residential CPP, where participants may reduce consumption from a variety of end uses, gas CPP participants mostly reduce space heating and water heating gas consumption during a winter morning event. Because of this, achievable potential from gas Residential CPP largely overlaps with achievable potential from other residential DLC products. Table 6-13 includes the peak-day achievable potential for the gas DR products along with the estimated levelized costs.

Table 6-12: Peak-Hour Gas DR Achievable Potential, 2039

Peak-Hour DLC Program Impacts			
Product	**Winter Achievable Potential (Dth)**	**Percent of System Peak Hour - Winter**	**Levelized Cost ($/Therm-hour)**
Residential DLC Thermostat - Direct Install	105	0.7%	$978
Residential DLC Thermostat - BYOT	114	0.8%	$803
Residential Water Heater DLC	92	0.6%	$2,883
Residential Critical Peak Pricing*	293	2.0%	$95
Commercial DLC Thermostat - BYOT	25	0.2%	$274

* Note potential from this product largely overlaps with potential from other residential DLC products.

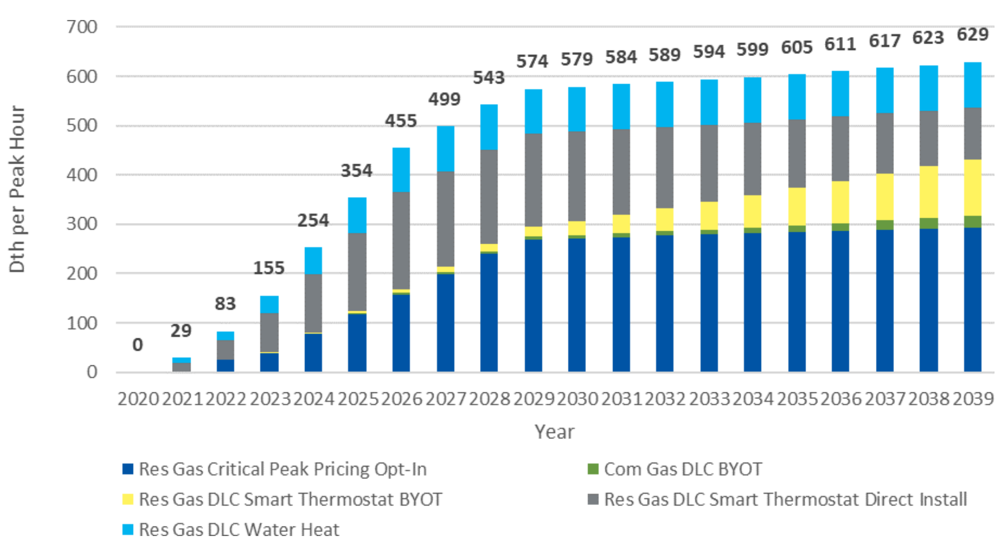
Table 6-13: Peak-Day Gas DR Achievable Potential, 2039

Peak-Day DLC Program Impacts			
Product	**Winter Achievable Potential (Dth)**	**Percent of System Peak Day - Winter**	**Levelized Cost ($/Therm-hour)**
Residential DLC Thermostat - Direct Install	206	0.1%	$499
Residential DLC Thermostat - BYOT	224	0.1%	$409
Residential Water Heater DLC	546	0.2%	$525
Residential Critical Peak Pricing*	1,204	0.4%	$23
Commercial DLC Thermostat - BYOT	81	0.0%	$84

* Note potential from this product largely overlaps with potential from other residential DLC products.

Figure 6-10 includes the peak-hour annual achievable potential for all the evaluated gas DR programs through 2039. The programs are stacked in order of levelized cost from lowest (Residential CPP) to the highest (Residential Water Heater DLC). DR programs are largely consumer-centric, and widespread adoption of DR programs may require extensive marketing and customer outreach to encourage participation in such programs.

Figure 6-10: Gas DR Peak Hour Potential by Program



6.5.3 Energy Efficiency Evaluation

The study developed a forecast of potential savings through EE programs. The DR savings were calculated for 2020 through 2039. Beyond 2039, the annual savings from DR programs were kept constant at 2039 levels.

Table 6-14 includes the forecasted 2039 baseline natural gas sales and EE achievable technical potential by sector. The study results indicate an achievable technical potential of roughly 49.4 million therms by 2039. Should all the EE programs prove cost-effective and implementable, the reduction would amount to a 19 percent reduction in forecasted 2039 sales.

Table 6-14: Natural Gas Cumulative EE Potential

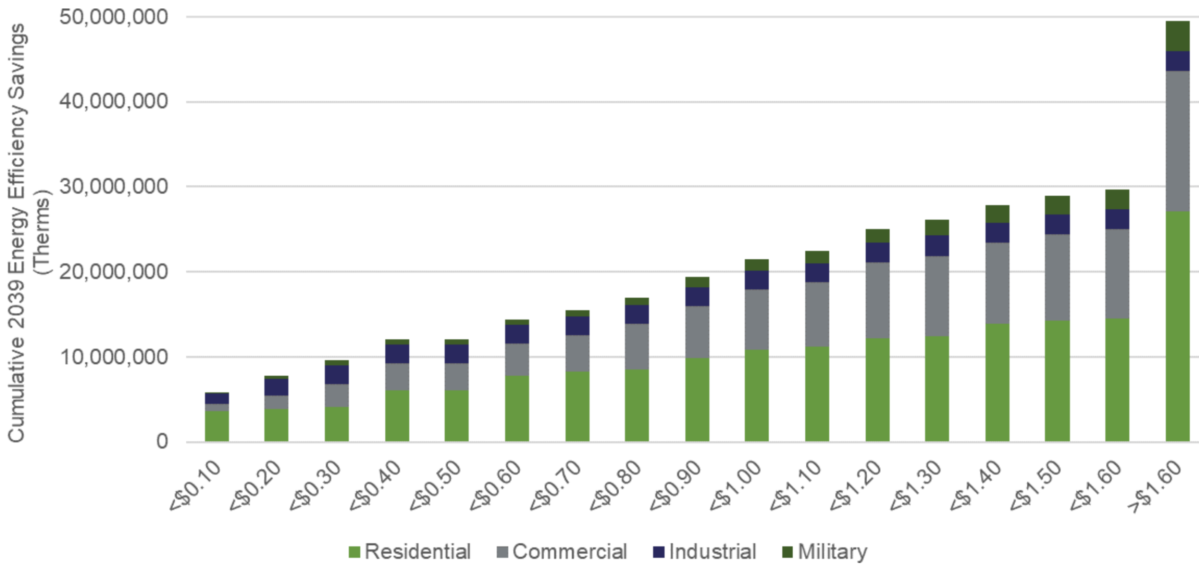
Sector	2039 Baseline Sales (Therms)	2039 Technical Potential (Therms)	Potential as Percentage of Sales	2039 Achievable Technical Potential (Therms)	Achievable Potential as Percentage of Sales
Residential	158,575,723	49,136,275	31.0%	27,150,308	17.0%
Commercial	73,938,458	28,765,607	39.0%	16,425,582	22.0%
Industrial	12,309,336	2,979,269	24.0%	2,409,227	20.0%
Military	17,304,963	6,069,078	35.0%	3,449,981	20.0%
Total	**262,128,480**	**86,950,229**	**33.0%**	**49,435,098**	**19.0%**

Figure 6-11 shows the annual cumulative achievable technical potential by sector. Similar to the electrical analysis, the study assumed most achievable discretionary opportunities would be acquired within the first 10 years of the study, from 2020 through 2029.

Figure 6-11: Annual Cumulative EE Potential by Sector

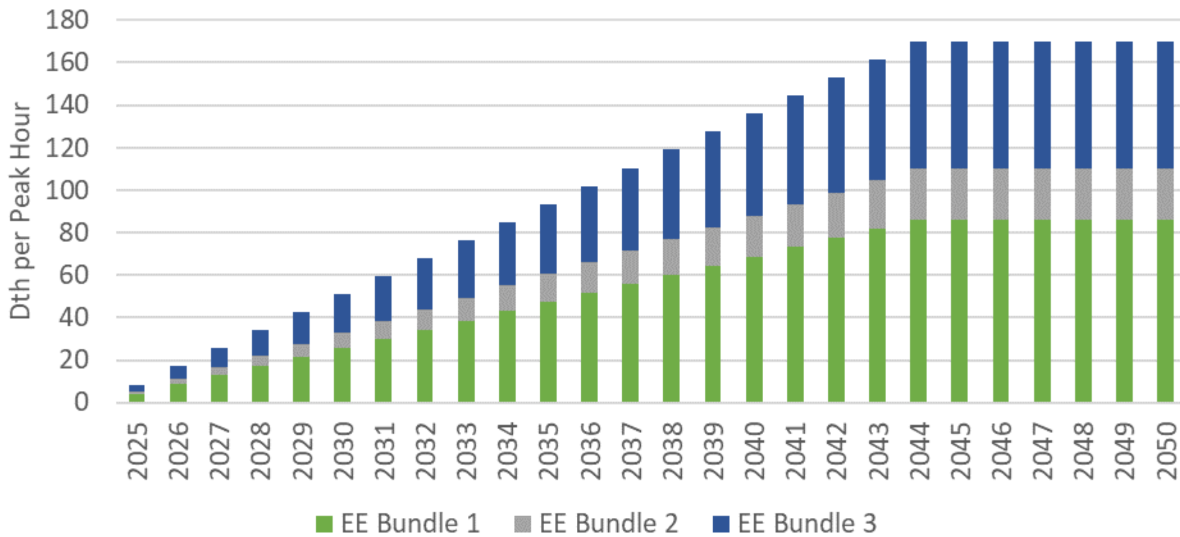
Figure 6-12 shows the relationship between achievable technical potential and the corresponding cost of conserved energy. For example, roughly 19.5 million therms of achievable potential would be available at a cost of less than $0.90 per therm.

Figure 6-12: Cumulative EE Potential by Cost of Conserved Energy



Seventeen individual EE bundles were developed as part of the DSM study. Bundles with a levelized cost below a hurdle rate of $4,817 per Dth per year were considered as resource options in the GIRP. The hurdle rate represents the cost of new pipeline capacity with air injection. In addition to energy savings, these programs will provide peak-day and peak-hour reductions which may, in turn, help defer the need to procure new resources. Figure 6-13 shows the impact of EE programs on peak hour demand experienced during peak days. As can be seen in the figure, the EE programs help to help reduce peak hour demand on peak days.

Figure 6-13: Gas EE Peak Hour Potential by Bundle



6.6 DSM NET IMPACTS

Table 6-15 includes the cumulative achievable potential for EE programs in 2039. EE programs could save up to 49.4 million therms by 2039, representing 19 percent of baseline forecasted sales. Table 6-16 shows the technical and achievable potential for DR programs evaluated in this study. Total natural gas DSM potential, representing nearly 2,261 therms of peak-day achievable technical potential and 629 therms of peak-hour achievable technical potential.

Table 6-15: 2039 Cumulative Achievable Technical EE Potential

Sector	2039 Baseline Sales (Therms)	2039 Achievable Technical Potential (Therms)	Achievable Potential as Percentage of Sales
Residential	158,575,723	27,150,308	17.0%
Commercial	73,938,458	16,425,582	22.0%
Industrial	12,309,336	2,409,227	20.0%
Military	17,304,963	3,449,981	20.0%
Total	**262,128,480**	**49,435,098**	**19.0%**

Table 6-16: 2039 Achievable DR Potential

Sector	Peak-hour		Peak-Day	
	2039 Achievable Potential (Dth/hr)	% of System Peak Hour	2039 Achievable Potential (Dth/day)	% of System Peak Day
Residential	604	4.1%	2,180	0.8%
Commercial	25	0.2%	81	0.0%
Total	**629**	**4.3%**	**2,261**	**0.8%**

7.0 RISK ANALYSIS

Providing reliable natural gas supply is a core business objective of Springs Utilities. In the formulation of a long-term plan, Springs Utilities is expected to deliver whatever volume is needed by gas customers under firm delivery tariff requirements. Limitations due to pipeline capacity restrictions are not acceptable and must be balanced with supply or demand-side resources. As part of meeting these requirements, Springs Utilities must evaluate potential risks associated with pursuing supply and demand-side options.

7.1 ECONOMIC CONDITIONS

Colorado Springs has experienced favorable economic conditions the past few years with strong growth in the residential and commercial sectors. Poor economic conditions could lower demand growth forecasts and reduce the need for additional natural gas supply. Alternatively, if economic growth is stronger than expected, natural gas consumption may grow faster than expected and require additional natural gas supply earlier than expected. To reflect these risk factors, a low and high demand forecast were evaluated as part of the GIRP process.

7.2 SUPPLY-SIDE OPTIONS

Supply-side options must be procured to ensure a steady supply of natural gas for Springs Utilities customers year-round.

7.2.1 Pipeline Capacity Constraints

Springs Utilities currently receives its natural gas supply via CIG. CIG is currently fully subscribed, with no additional capacity available without expanding infrastructure. If Springs Utilities were to pursue additional pipeline capacity, CIG would have to embark on a capacity expansion project, or a new greenfield pipeline by CIG or another pipeline company would have to be built. Both options require multiple years of planning and regulatory review before construction can be started. Additionally, GHG regulations and emission reduction targets could reduce the appetite for large capital expenditures on natural gas assets and potentially strand newly constructed natural gas assets within their operational life. These factors should be considered when evaluating supply-side options that require natural gas transportation to Springs Utilities system via pipelines. Expanding existing and constructing new peak shaving facilities are feasible options as an alternative to meet pipeline capacity limitations.

7.2.2 Pipeline Supply Interruptions

Since Springs Utilities primary source of natural gas is the CIG pipeline, interruptions in flows on CIG would greatly impact Springs Utilities natural gas supply. These events are rare, but extreme weather events, production disruptions, and large demand spikes could all dramatically impact the ability of CIG to deliver natural gas to Springs Utilities system. Regardless of pipeline interruptions, Springs Utilities is expected to deliver whatever volume is needed by customers under firm delivery requirements. When evaluating supply-side options to meet peak demand requirements, the possibly of pipeline interruptions must be considered. Springs Utilities existing PAP facility does provide an on-system resource capable of meeting some of the system's natural gas demand, but only for a limited amount and duration.

7.2.3 Greenhouse Gas Regulations

In recent years, Colorado has passed multiple state laws mandating reductions in greenhouse gas emissions, new regulations related to oil and gas operations, and improved energy efficiency standards. The definitive impacts of these regulations remain to be seen, but potential outcomes could include:

- As Springs Utilities retires coal-fired power plants, there may be an increase in natural gas demand to serve new natural gas electric generating units, most likely during peak weather conditions
- Increases in electrification along with energy efficiency improvements could reduce retail natural gas demand growth
- Gas distribution assets could be stranded due to increased electrification
- Higher cost of Colorado-sourced natural gas supplies due to increased setbacks for oil and gas wells and along with GHG emission controls
- Potential rate increases on the CIG system due to decreased natural gas demand, resulting in higher per-unit costs for Springs Utilities
- Regulatory costs imposed on GHG emissions from gas distribution operations.

7.3 DEMAND-SIDE OPTIONS

Key steps in implementing DSM programs identified in the CADMUS Report include the following:

- Perform a feasibility analysis of program(s) against supply-side options, first targeting programs that provide peak-hour capacity
- Identify potential customer populations for selected programs
- Develop a pilot program(s) with evaluation metrics
- Obtain funding and launch pilot programs to a limited number of participants
- Evaluate costs, load reduction results, and resource requirements
- Determine if programs are viable, and then offer to larger customer population(s)

Successful implementation of DSM programs will require time and resources to evaluate viable programs and to determine the actual impacts to natural gas consumption. Programs are not guaranteed to fully reach the estimated potential from the CADMUS study. Additionally, since DSM programs are consumer centric, the adoption of such programs are voluntary and could require substantial incentives and advertising to see meaningful customer adoption. The required lead time for DSM programs may not provide required savings in a fast enough manner to meet firm resource requirements. Regardless, DSM programs can provide a valuable role in Springs Utilities gas resource plan, but the timing, implementation, and impacts will need to be closely evaluated to ensure a reliable supply of natural gas.

7.4 AVOIDED COSTS

7.4.1 Commodity Related

Springs Utilities load profile is heavily driven by space and water heating and as a result there is substantial Springs Utilities capacity entitlements available in warmer weather on the CIG system. There is an opportunity to leverage that resource for expanded natural gas fired electric generation that will primarily operate to serve cooling load.

7.4.2 Infrastructure Related

The revision in the hourly and daily load forecasting criteria delayed the need for new peak shaving facilities that will reduce the exposure level for stranded assets as a result of emerging GHG emission regulations.

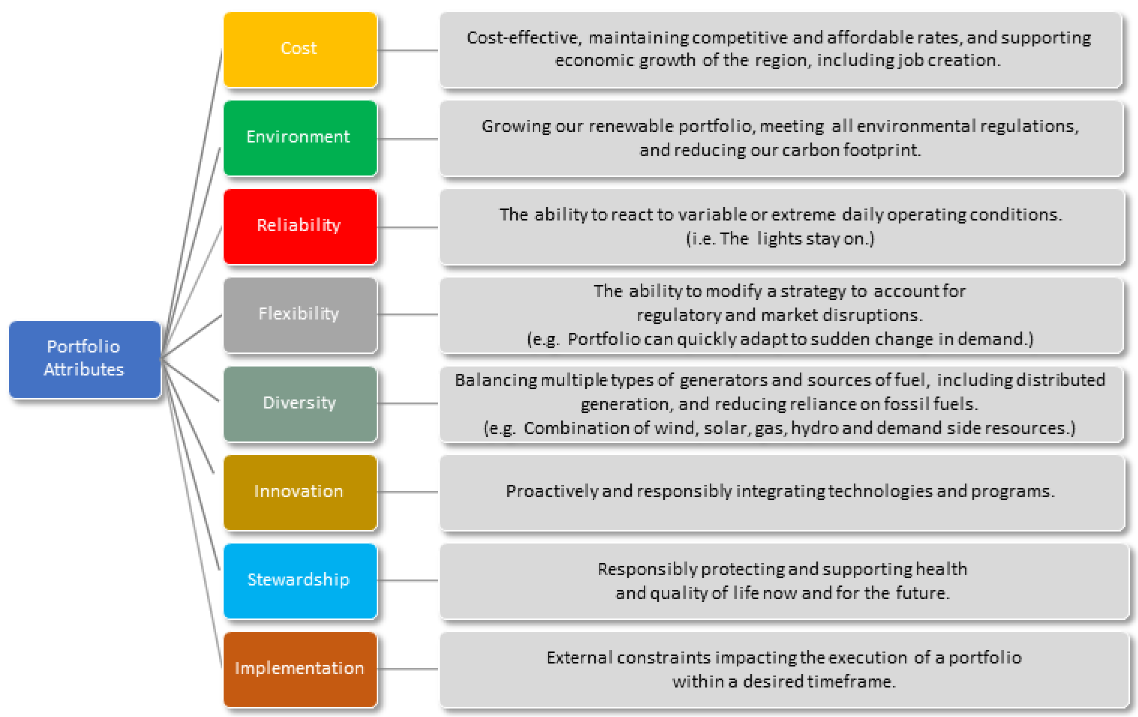
8.0 RESOURCE INTEGRATION (PORTFOLIO SELECTION)

The second main phase of the GIRP consisted of three main activities. The modeling and analyses of GIRP portfolios using assumptions and inputs from the prior phase, evaluating of GIRP portfolio results, and risk analysis.

8.1 PORTFOLIO EVALUATION CRITERIA

To assist with evaluating potential GIRP portfolios alignment with the GIRP's goals, evaluation attributes were developed to differentiate portfolios. Springs Utilities initially developed eight portfolio attributes that represent factors important to Springs Utilities customers. Springs Utilities solicited customer feedback on the original eight attributes to gauge the relative importance of each attribute. The original eight attributes are included in Figure 8-1.

Figure 8-1: GIRP Original Portfolio Attributes



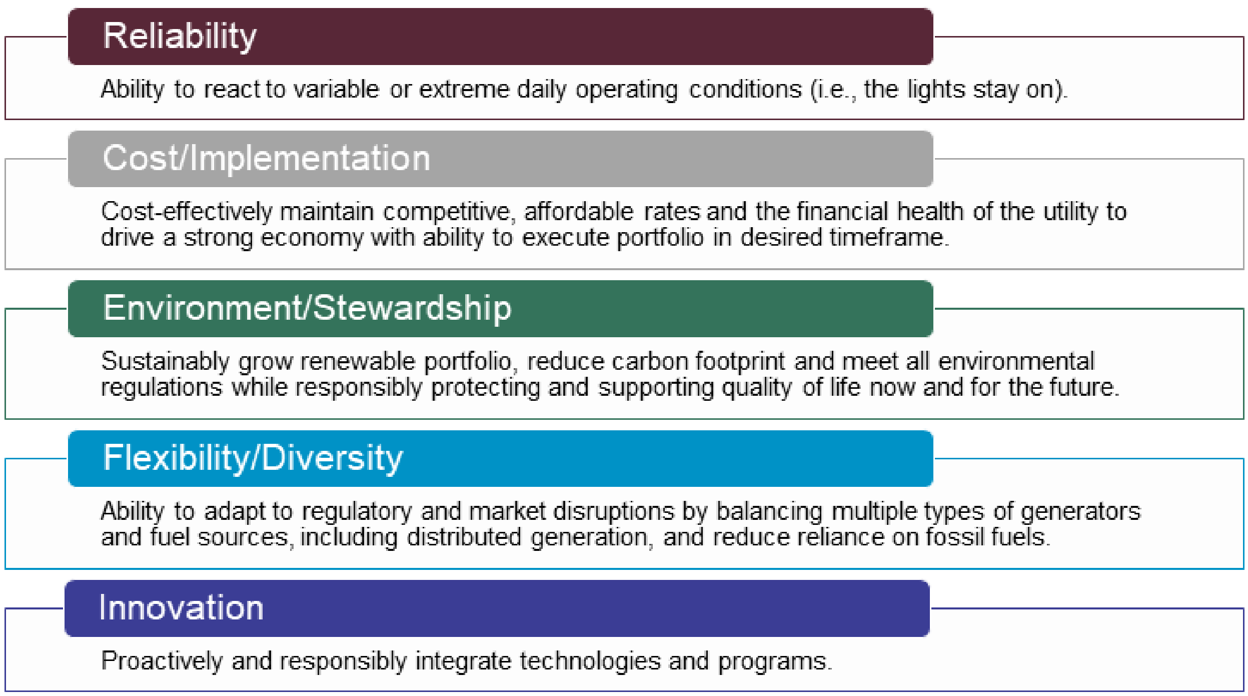
Critical feedback from customer surveys provided a recommendation to consolidate the eight portfolio attributes down to five. The main factors leading to consolidation of attributes included:

- Combining related concepts
- Making measurements meaningful
- Aligning with Energy Vision pillars and goals

- Simplifying the scoring process
- Consideration of stakeholder input

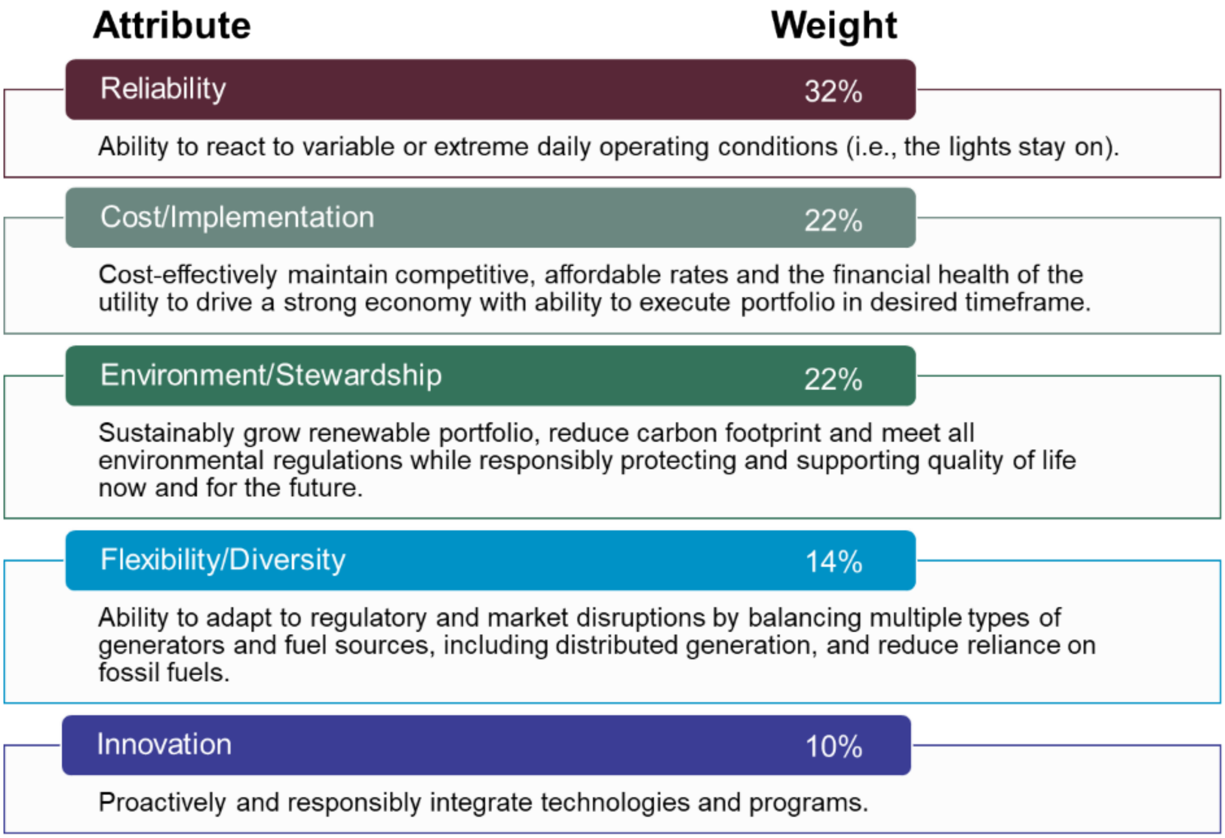
Cost and Implementation were consolidated into the Cost/Implementation attribute. Environment and Stewardship were combined into the Environment/Stewardship attribute, and Flexibility and Diversity were combined into the Flexibly/Diversity attribute. The final five attributes and subsequent definitions are summarized in Figure 8-2.

Figure 8-2: Final GIRP Portfolio Attributes



After determining critical attributes for portfolio evaluation, a weighting was applied to each attribute to quantify its level of importance. The weighting process was completed through public engagement and stakeholder feedback. Based on the stakeholder feedback, Reliability was determined to be the most important attribute, followed by a tie between Cost/Implementation and Environmental/Stewardship. The weighting percent assigned to each of the five attributes is displayed in Figure 8-3.

Figure 8-3: GIRP Attribute Weighting



Each attribute is comprised of multiple criteria that contributed to the attribute's overall weighting. Since each criterion's impact differs for each attribute, a weighting value was applied to each criterion with the total equal to 100 percent.

- **Reliability** – The reliability attribute focused on ensuring a portfolio would have enough resources available to ensure sufficient natural gas supply during peak-day and peak-hour periods. The criteria determined for reliability along with their relative weightings are highlighted in Table 8-1.

Table 8-1: Reliability Criteria Weighting

Criteria 1 (78%)	Criteria 2 (6%)	Criteria 3 (16%)
Capacity	Energy	Balancing

- **Cost and Implementation** – The cost attribute was measured by lowest NPVRR based on revenue requirements (RR) and implementation. This metric reflects an "all-in" cost of meeting Springs Utilities customers natural gas requirements over the GIRP study period. A present value incorporates the logic that a dollar spent in 2020 is worth more than a dollar spent in 2050 due to the time value of money. The criteria for this attribute are highlighted in Table 8-2.

Table 8-2: Cost and Implementation Criteria Weighting

Criteria 1 (82%)	Criteria 2 (18%)
Cost RR	Cost Imp

- **Environment and Stewardship** – Consistent with Colorado legislation, the highest weighted criteria for the Environmental and Stewardship attribute measures GHG reduction from 2005 levels. The criteria for this attribute are included in Table 8-3.

Table 8-3: Environment and Stewardship Criteria Weighting

Criteria 1 (100%)
Environment

- **Flexibility and Diversity** – This attribute measures the ability of the natural gas supply to flexibly meet the fluctuations in demand throughout the year. The different criteria for this attribute are included in Table 8-4.

Table 8-4: Flexibility and Diversity Criteria Weighting

Criteria 1 (36%)	Criteria 2 (50%)	Criteria 3 (14%)
Flex Peak	Div. Capacity	Stranded

- **Innovation** – Springs Utilities identified demand response as an area where they can directly influence and implement innovation. The criteria for demand response is measured by the percent of gas demand reduced through DR programs. For new resources, an innovation score was assigned based on the maturity of the technology. The criteria for this attribute are highlighted in Table 8-5.

Table 8-5: Innovation Criteria Weighting

Criteria 1 (100%)
Innovation

8.2 PORTFOLIO DEVELOPMENT

Different portfolios were developed through a public process to incorporate a reasonable range of capacity options, DSM programs, and resource timing. Six portfolios were evaluated in the GIRP with variations of a reference case, new pipeline capacity, propane air facilities (expanded and new), LNG, and DSM programs (DR and EE). DSM programs were assumed to be developed with a pilot beginning in 2022 and widespread implementation targeted for 2025. Most of the DSM programs are based on a 20-year implementation. All portfolios include expanding the existing propane air plant, since it is the least-cost option to provide additional supply resources. The PAP's capacity increases as customer load increases allowing sufficient blending capacity at the North Gate Station ("NGAT"). Table 8-6 includes the hourly capacity added by incremental volume and Table 8-7 includes the forecasted timing of resource installation.

Table 8-6: LDC Portfolio Capacity Expansion Volumes

Portfolio	Expand Existing PAP	New PAP	New PAP Expanded	LNG Plant	LNG Expanded	New TF1 + Air Injection	Cost-Effective DR less Price	Cost-Effective EE
	(dth/hr)	(dth/hr)	(dth/hr)	(dth/hr)	(dth/hr)	(dth/hr)	(dth/hr)	(dth/hr)
LDC Portfolio 1	300	650	500			150		
LDC Portfolio 2	300					1,150		150
LDC Portfolio 3	300			650	500			150
LDC Portfolio 4	300	650				150	500	
LDC Portfolio 5	300	650	500					150
LDC Portfolio 6	300	650					500	150

Table 8-7: LDC Portfolio Capacity Expansion Timing

Portfolio	Expand Existing PAP	New PAP	New PAP Expanded	LNG Plant	LNG Expanded	New TF1 + Air Injection	Cost-Effective DR less Price	Cost-Effective EE
LDC Portfolio 1	2032	2034	2040			2049		
LDC Portfolio 2	2032					2034		2025
LDC Portfolio 3	2032			2034	2041			2025
LDC Portfolio 4	2037	2039				2049	2025	
LDC Portfolio 5	2032	2034	2043					2025
LDC Portfolio 6	2038	2040					2025	2025

Figure 8-4 through Figure 8-9 include the forecasted peak-hour demand against each respective portfolio's natural gas supply. Although shown as a resource in the portfolio charts, DSM programs are actually load reductions. Load reductions also reduce the capacity of the PAP facility since natural gas flow required to maintain proper blending capacity is dependent on gas flow through NSTA.

Figure 8-4: GIRP Portfolio 1 (Reference Case)

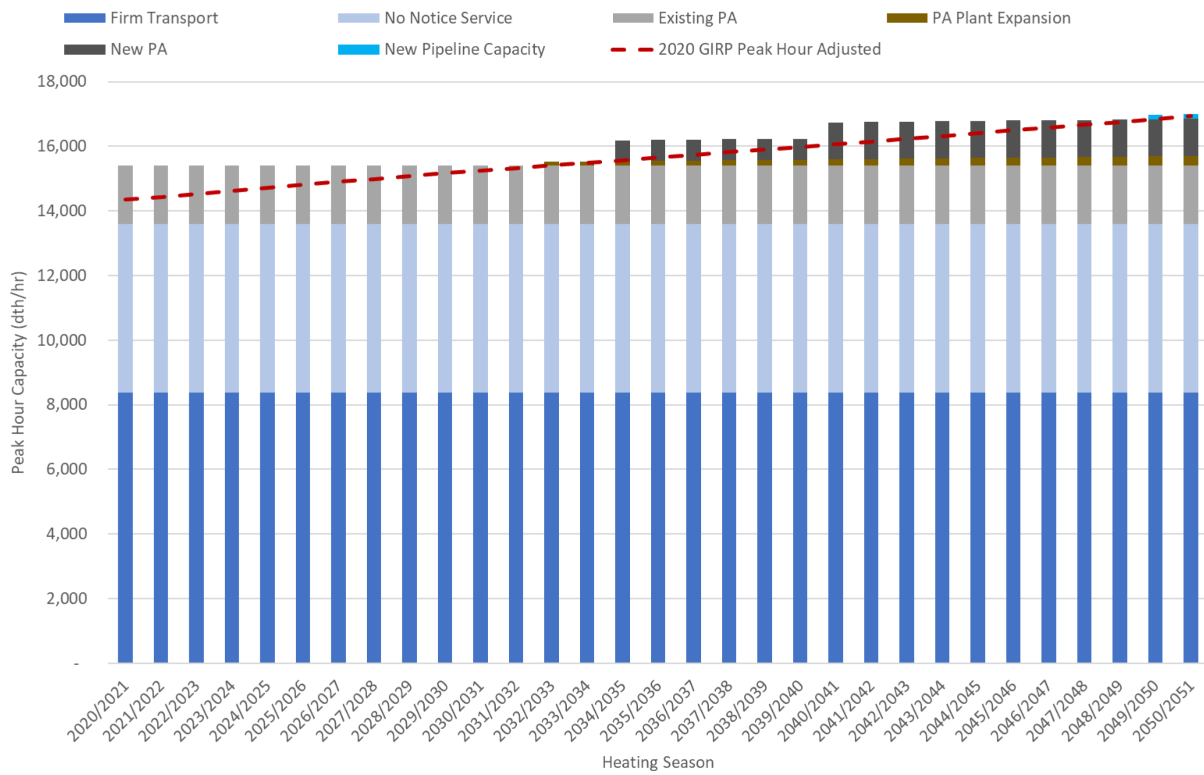


Figure 8-5: GIRP Portfolio 2 (New Pipeline Capacity)

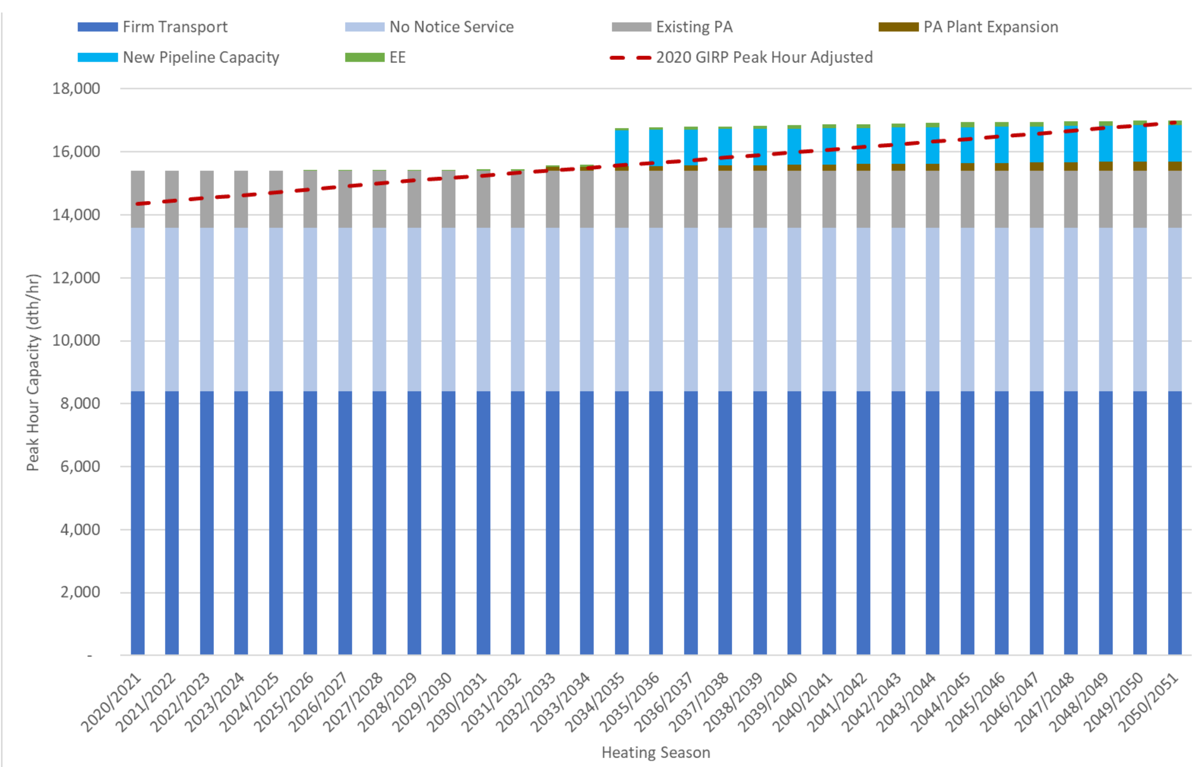


Figure 8-6: GIRP Portfolio 3 (LNG Peak Shaving)

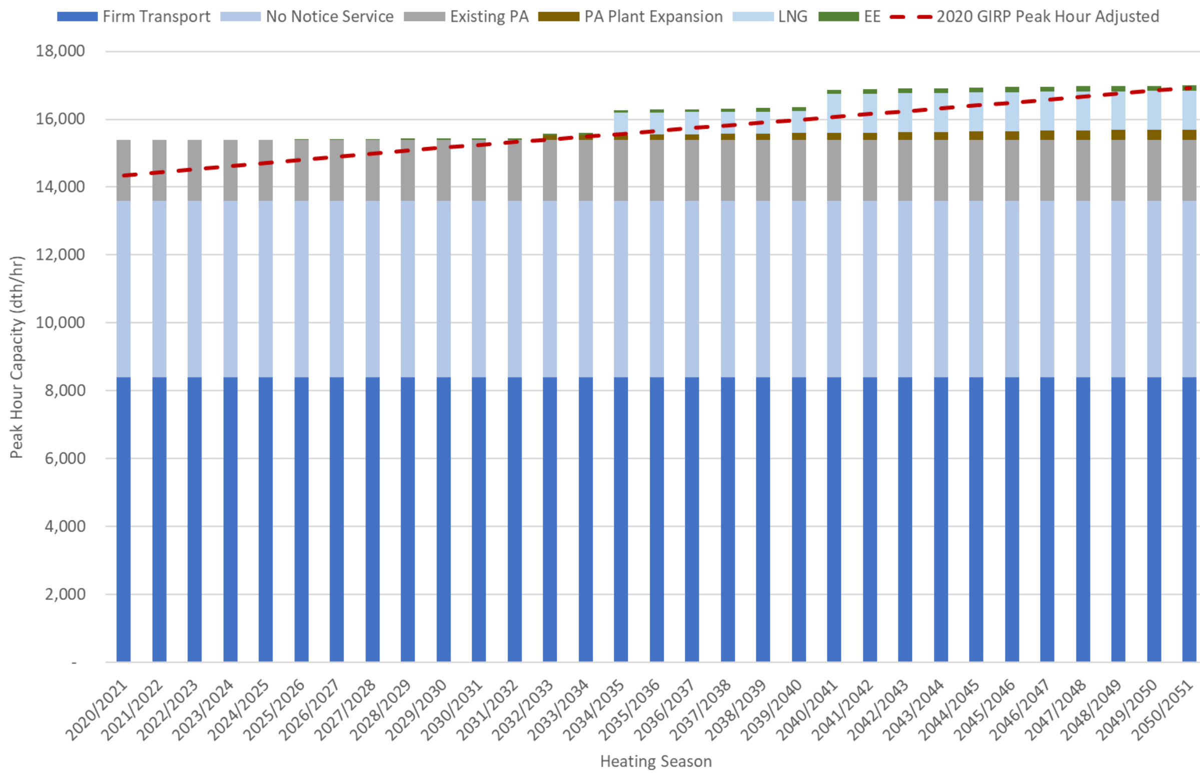


Figure 8-7: GIRP Portfolio 4 (Demand Response)

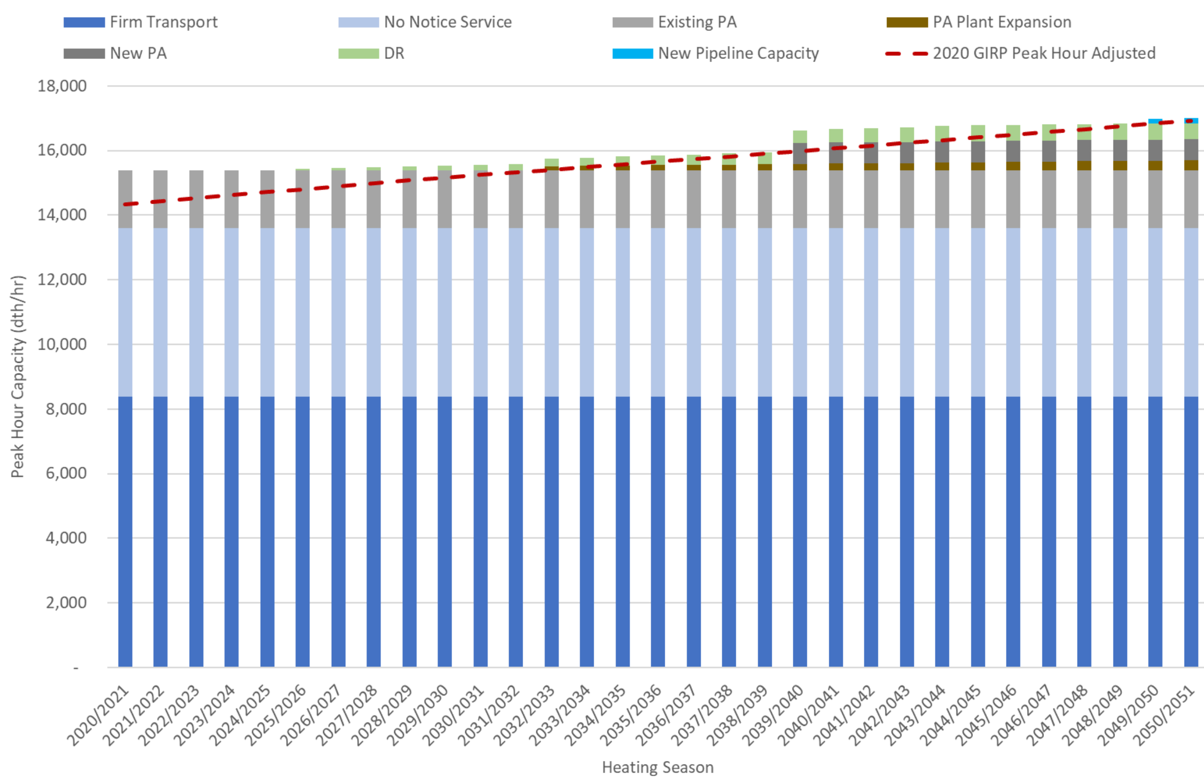


Figure 8-8: GIRP Portfolio 5 (Energy Efficiency)

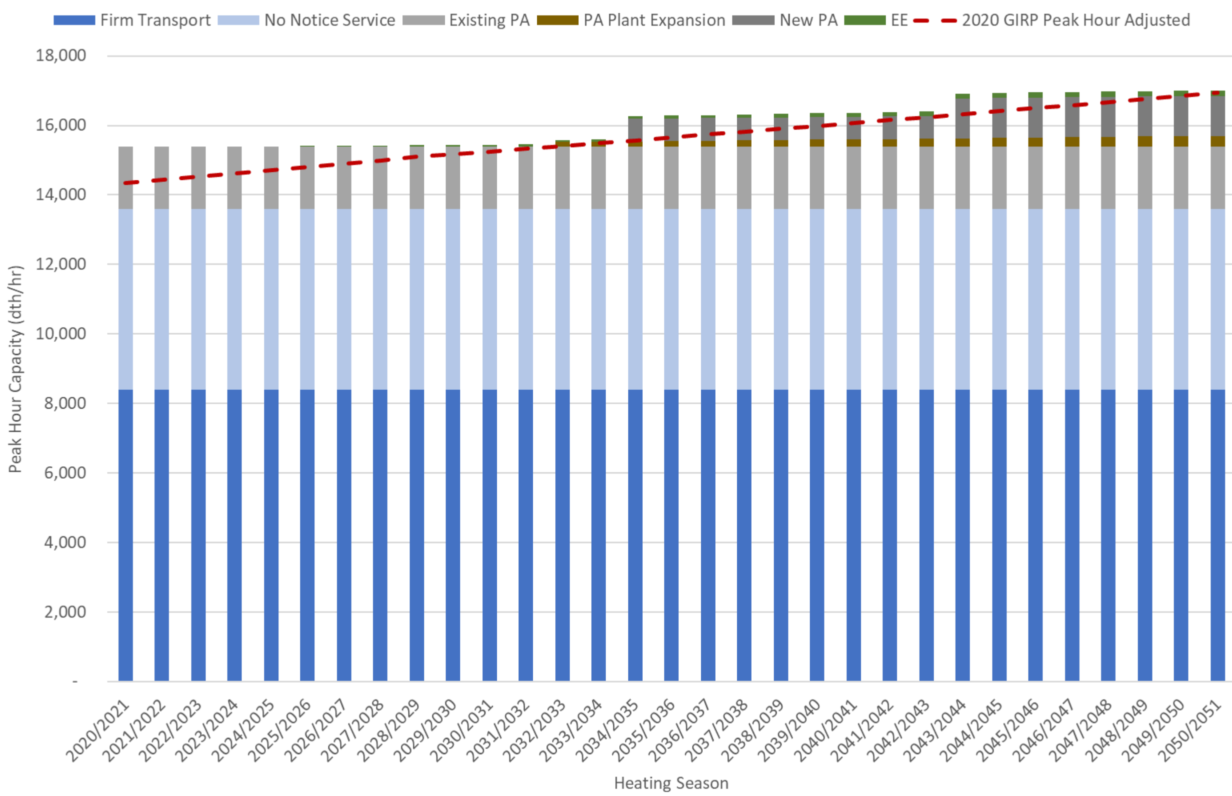
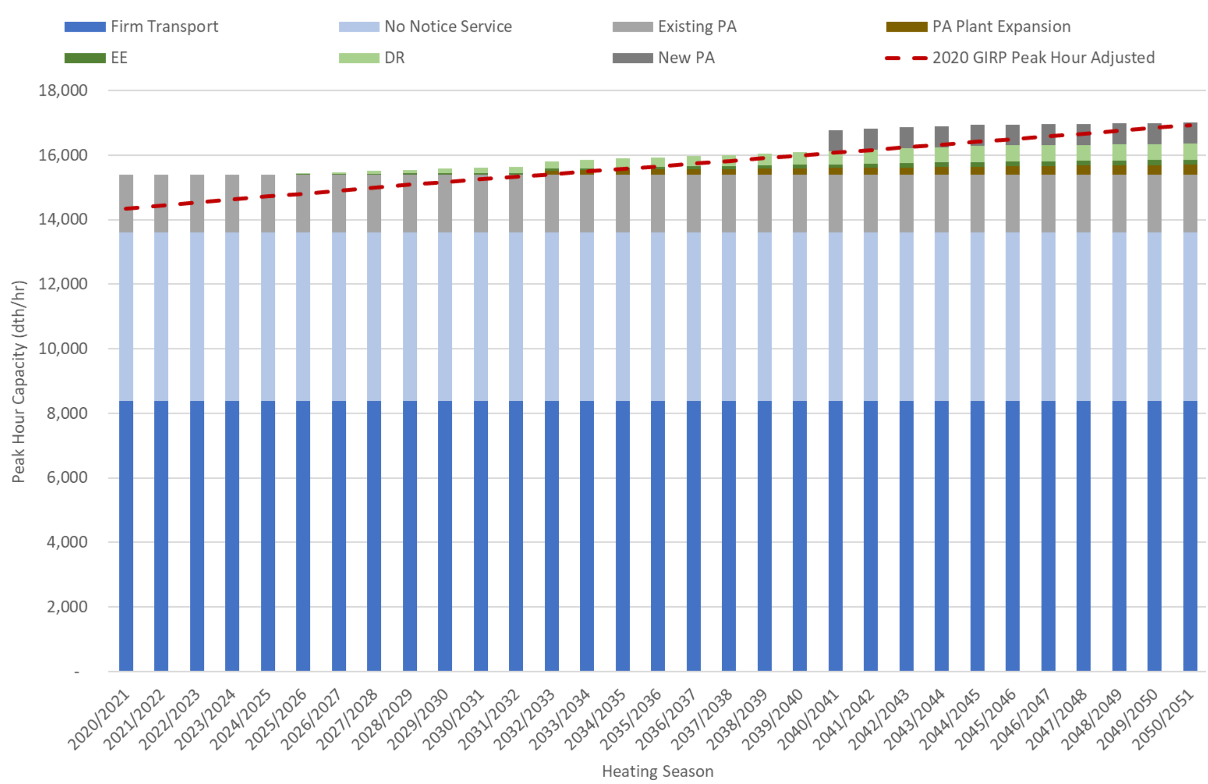


Figure 8-9: GIRP Portfolio 6 (DSM)



GIRP Portfolio 1 is the base (reference) case that was analyzed assuming normal load growth. Portfolio 6 is the similar to Portfolio 1 but with load growth reduced due to the implementation of EE and DR programs. The impacts of the DSM programs delay installation of a new PAP in Portfolio 6.

8.2.1 GIRP Pathway Development

After determining various portfolios, pathways were developed to narrow the scope and focus of the decision-making process to near-term activities. Pathways act as a way to further summarize and group together the portfolios based on common characteristics. The GIRP analysis evaluated portfolios and pathways to determine important factors over the next 10 years, while keeping flexibility for long term changes in subsequent GIRPs. Each portfolio falls into a specific pathway, based on New Pipeline capacity, New Peak Shaving Capacity, or new DSM programs. Overall, four pathways were identified in the GIRP study and the six portfolios were assigned to one of the pathways and Table 8-8 includes a description of the four pathways.

Table 8-8: GIRP Pathway Descriptions

Pathway	Description
Reference	Business as usual case where the existing propane air facility is expanded to meet increasing customer demand. An additional propane air facility is constructed in the latter half of the analysis as customer growth continues.
A	Portfolios that heavily rely on new pipeline capacity to meet natural gas supply requirements along with EE programs.
B	Portfolios that expand the existing propane air facility, add EE programs, and construct a new propane air facility to meet customer demand.
C	Portfolios where DSM programs used in combination with new peak shaving capacity to meet customer demand.

Table 8-9 summarizes the different pathways and the different portfolios that are characterized by each pathway.

Table 8-9: GIRP Pathways and Portfolios

Pathway	Reference	A - New Pipeline Capacity	B - New Peak Shaving Capacity	C - DSM + New Peak Shaving Capacity		
Portfolio	1	2	3	4	5	6
2022						
2025		Energy Efficiency	Energy Efficiency	Demand Response	Energy Efficiency	DR + EE
2030						
2032	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion	Existing Propane Air Expansion
2034	New Propane Air	Expand/New Pipeline Capacity	New LNG Plant		New Propane Air	
2035						
2040	Expand Propane Air		Expand LNG Plant	New Propane Air		New Propane Air
2043					Expand Propane Air	
2050	Expand/New Pipeline Capacity			Expand/New Pipeline Capacity		

8.3 PORTFOLIO EVALUATION

Each portfolio was evaluated using net present value and revenue requirement methodology on a 30-year horizon. The 30-year revenue requirement for each portfolio is included below in Table 8-10. After the initial portfolio evaluation, portfolios 1, 4, and 6 were identified for further refinement.

Table 8-10: GIRP Portfolio Results Summary

Portfolio	Pathway	30-year Enterprise Revenue Requirement ($B)	Average Annual Revenue Requirement ($B)	30-year Gas Revenue ($B)
1	Ref	$35.72	$1.191	$5.74
2	A	$35.78	$1.193	$5.79
3	B	$35.74	$1.191	$5.76
4	C	$35.71	$1.190	$5.73
5	C	$35.72	$1.19	$5.73
6	C	$35.71	$1.19	$5.73

8.4 SENSITIVITY ANALYSIS

When applicable, sensitivity analyses were performed on each of the portfolios. Table 8-11 shows the main sensitivities performed as part of the analysis. The table includes the difference in each portfolio's

NPVRR for each sensitivity compared against the reference case. If a negative value is shown, the NPVRR for the sensitivity is less than the reference case. The results of the sensitivity analysis highlight uncertainties in the future and emphasize that Springs Utilities should maintain flexibility in the GIRP's action plan to mitigate the unknown.

Table 8-11: GIRP Portfolio Sensitivity Analysis

Portfolio	Pathway	Attribute Ranking	Total Score Normalized	Reference NPVRR ($M)	NPVRR Delta from Reference ($M)			
					High Load	Low Load	High DSM	High DR
6	C	1	100	$12.5	$7.8	($12.5)	($2.3)	NA
4	C	2	96.6	$13.3	$22.5	($13.3)	NA	($1.7)
1	Ref	3	96.2	$18.8	$37.8	($18.8)	NA	NA

From the sensitivity analysis, several key takeaways were determined. Table 8-12 includes an overview of the key conclusions reached during the sensitivity analysis.

Table 8-12: GIRP Sensitivity Takeaways

Sensitivity	Takeaway	Cost Impact
High Load Growth	Additional transport/air injection capacity needed on interstate pipeline, and distribution system improvements	Increase
Low Load Growth	Would reduce or eliminate the need for new transport/air injection capacity. Could result in reducing existing capacity resources (fixed costs).	Decrease
Renewable Natural Gas	Program is voluntary for municipally owned utilities.	Increase
Non-firm Gas Options	Some new distributed generation units can be served by existing LDC on a seasonal basis. Secondary fuel needed for extremely cold weather.	Decrease
Peaking Capacity Options	Propane Air expansions are lower cost but blend limited. LNG options require a detailed study to assess feasibility and may be advantageous to leveraging LDC and DG capacity/energy combinations.	Decrease
Energy Efficiency and Demand Response	Requires program development and proof of concept.	Decrease
Distributed Generation	Large capacity units are better served by non-air injected interstate pipeline as air injection capacity adds 86% to fixed pipeline reservation costs	Increase

8.5 RISK MODELING

A detailed risk analysis was performed for the top three portfolios. The risks identified for each portfolio and a potential mitigation approach are summarized in Table 8-13.

Table 8-13: GIRP Risk Analysis

Portfolio	Risk	Mitigation
1	• Potential for public push-back for new PAP plant related to land use, visual impact, and storage of flammable energy commodities; land availability	• Robust public process and state-of-the-art safety measures; advance land purchase
4, 6	• Reliance on untested DSM programs; DR has a behavioral component creating a reliability risk • Attracting participants while maintaining cost-effectiveness • Potential for public push-back for new P/A plant related to land use; visual impact, and storage of flammable energy commodities; land availability	• Prove concept with pilot DSM programs and technology • Program promotion with rebates and cost management • Robust public process and state-of-the-art safety measures; advance land purchase

8.6 PORTFOLIO SELECTION

The six portfolios were evaluated based on the attribute weighting established earlier in the GIRP process. A normalized score was determined for each portfolio and Table 8-14 includes the attribute scores for each portfolio. The green cells in the table indicate the portfolio with the highest score for each attribute. These portfolios were further discussed with various stakeholders, and the top three portfolios were identified as Portfolio 1, Portfolio 4, and Portfolio 6.

Table 8-14: Portfolio Attribute Scoring

Portfolio	Pathway	New Resources	Attribute Ranking	Normalized Score	Reliability	Cost / Implementation	Environment / Stewardship	Flexibility / Diversity	Innovation
6	C	Demand Response, Energy Efficiency, PAP Expansion, New PAP	1	100	83.5	100	100	86.8	72.7
4	C	Demand Response, PAP Expansion, New PAP, New Pipeline Capacity	2	96.6	85	83.5	95.5	100	70.1
1	Ref	PAP Expansion, New PAP, New Pipeline Capacity	3	96.2	86.5	86	95.5	98.6	46.5
5	C	Energy Efficiency, PAP Expansion, New PAP	4	93.8	86.2	85.8	100	79.1	46.5
3	B	Energy Efficiency, PAP Expansion, New LNG Plant	5	92.8	100	48.6	100	85.9	100
2	A	Energy Efficiency, PAP Expansion, New Pipeline Capacity	6	77.7	99.5	36.4	100	34.2	46.5

8.6.1 Portfolio 1

Portfolio 1 represents a business-as-usual case with expansion of the existing PAP facility in the early 2030s and the addition of a new PAP facility by the mid-2030s. This portfolio does not represent a drastic shift from existing system operations and has fewer technical risk than alternative portfolios. This portfolio however does not have explicit actions taken to reduce natural gas consumption and therefore GHG emissions. Additionally, this portfolio is reliant on constructing new capacity on Springs Utilities system which exposes Springs Utilities and its customers to stranded asset risks in the event of increased electrification. There could be additional public pushback to the construction of a new PAP facility which could complicate capacity expansion efforts. This portfolio does have flexibility due to the ability to change the timing of new resources in future years and the addition of peak-shaving capacity on the system.

8.6.2 Portfolio 4

Portfolio 4 represents a moderate change to system operations. The portfolio includes new demand response programs by 2025, expansion of the existing PAP facility in the early 2030s and the addition of a new PAP facility by 2040. Incorporating DR programs in this portfolio aligns with Colorado state goals to reduce GHG emissions and defers the construction of a new PAP facility as compared to Portfolio 1. The construction of a new PAP facility could expose Springs Utilities and its customers to stranded asset risks in the event of increased electrification. There could be additional public pushback to the construction of a new PAP facility which could complicate capacity expansion efforts. This portfolio does have considerable flexibility due to the ability to change the timing of new resources in future years and the addition of peak-shaving capacity on the system. Additionally, the deferral of the new PAP facility allows Springs Utilities additional time to evaluate other potential options and gather the impacts of various regulatory and legislative requirements.

8.6.3 Portfolio 6

Portfolio 6 provides an aggressive expansion in demand-side programs. The portfolio includes new demand response and energy efficiency programs by 2025, expansion of the existing PAP facility in the early 2030s and the addition of a new PAP facility by 2040. The inclusion of DR and EE programs in this portfolio aligns with Colorado state goals to reduce GHG emissions and defers the construction of a new PAP facility as compared to Portfolio 1. The construction of a new PAP facility could expose Springs Utilities and its customers to stranded asset risks in the event of increased electrification. There could be additional public pushback to the construction of a new PAP facility which could complicate capacity expansion efforts. This portfolio does have considerable flexibility due to the ability to change the timing of new resources in future years and the addition of peak-shaving capacity on the system. Additionally, the deferral of the new PAP facility allows Springs Utilities additional time to evaluate other potential options and gather the impacts of various regulatory and legislative requirements.

Portfolio 6 was approved by the Utilities Board in June 2020 as the planning path to pursue going forward.

9.0 DISTRIBUTION SYSTEM PLANNING

9.1 OVERVIEW

Springs Utilities distribution system begins at the city gate stations and continues to the outlet of the customer meter. Springs Utilities' goal is to design, construct, operate and maintain this system to deliver natural gas to every customer in a safe, reliable, and cost-effective manner. Areas specific to distribution planning improvements are identified via system network modeling. Furthermore, the recent integration of customer growth forecasting and localized distribution planning enables Springs Utilities to better coordinate targeted distribution projects that are responsive to specific customer growth patterns.

Springs Utilities is in a good position to serve newly developed areas at a relatively low cost due mainly to two factors. Growth on the east side of Marksheffel Road is near the city gate stations avoiding further strain on the already stressed extensive western side of the gas distribution system. And secondly, with natural gas use per customer declining due to improved appliance efficiency and energy conservation measures, the distribution system in existing areas of the city should be able to serve infill developments without adding significant infrastructure.

The ability of the distribution system to deliver needed volumes to specific geographic locations is analyzed using network modeling software to identify locations where delivery pressures would not meet customer needs. Additionally, the pipeline model allows computer simulation of new projects to evaluate the ability to serve customer growth. A capacity expansion at the McClintock gate station and potential 150P system reinforcements are planned in the near future to adequately serve new customer growth and new gas fired power generation units. Capacity margin stress tests were modeled for power plants, military bases and single gate station failures in order to identify any relative weakness in the system.

9.2 NETWORK MODELING

When designing new main extensions, network modeling is essential in optimizing the size for pipes (mains and services) and pressure regulator stations to meet current and future demands. Springs Utilities conducts gas distribution system load studies using the steady state pipeline network analysis software "Synergi®." The Synergi modeling tool allows Springs Utilities to analyze and interpret solutions graphically, based on the gas customer load and location throughout the service territory. Network modeling assists in master planning to optimally size gas mains and pressure regulator stations avoiding expensive replacement/reinforcement projects in the future due to under-sizing.

Figure 9-1: Springs Utilities Natural Gas Service Area Map

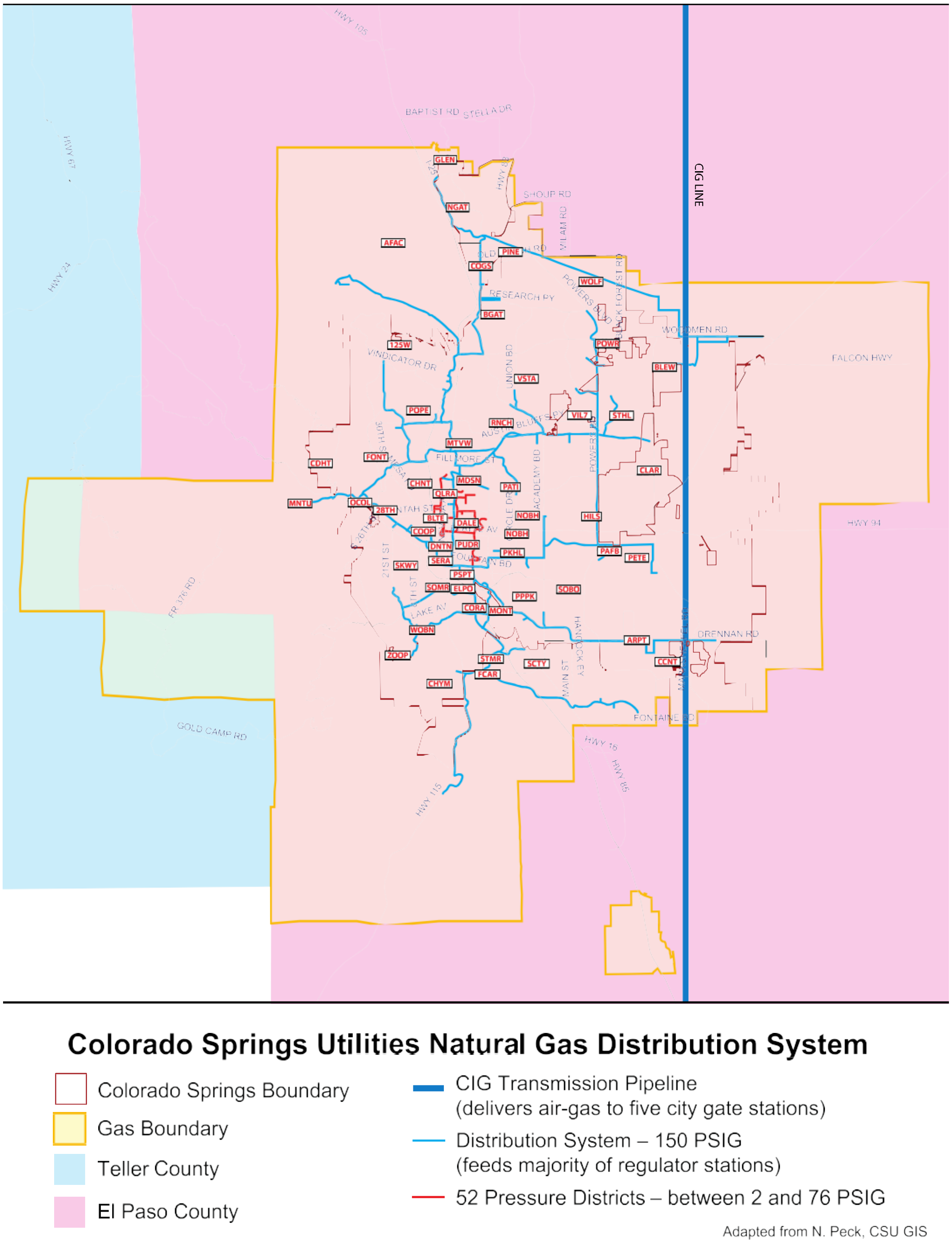


Figure 9-1 shows the relative location of the interstate pipeline (where natural gas enters the Springs Utilities network) on the east side of the Colorado Springs service territory with the vast majority of the distribution system creating a westward web to provide natural gas to gas customers.

9.2.1 Model Creation

With the help of the software and data from the Geographical Information System (GIS) Springs Utilities has accurately modeled the current distribution system. Facility properties such as pipe internal diameter, connectivity, pressure regulator station size, and valve operating settings are captured to construct the pipe network model.

The city gate stations deliver natural gas at a pressure of 145 psig to an all-steel 150 psig MAOP (maximum allowable operating pressure) system. This system acts as the “backbone” to distribute natural gas throughout the service territory.

From the 150 psig MAOP system, there are currently 47 isolated pressure districts within the Springs Utilities service territory. There are approximately 137 regulator stations throughout the service territory that lower the pressure from 145 psig to a range of fixed levels between 2 psig and 76 psig; most pressure districts are fed by more than one regulator station. The pressure districts distribute natural gas throughout a specified area, and finally to customers.

Customer usage data from the customer billing system is added as a modeling component in order to analyze system capacity and operation.

9.2.2 Modeling Benefits

Once the model is created, the results are used for numerous purposes, such as:

- Determining appropriate sizing for both new and renewal pipe projects to support current and future customer loads.
- Identify system bottlenecks and provide insight into the capacity margin in the system (through capacity stress testing of the system).
- Analyze critical scenarios, such as key equipment failures, natural disaster events, severe weather and excavator damage.
- Create system alarm points and simulate distribution system performance (such as isolating a portion of the system, creating a one-way feed, etc.).
- Facilitate main replacement projects where portions of the system can only be taken out of service certain times of the year.

9.2.3 Gas Distribution Model Verification

In order to improve the model’s accuracy, verification is performed by comparing actual operating data with predicted model values for peak-hour and peak-day. Telemetry (automated communication and data collection) equipment gathers the actual pressure values at various locations through the system and the flow volumes at the city gate stations. The telemetry data points are used to validate the accuracy of the model. Areas with a noticeable difference between predicted and actual pressure are reviewed in more detail, and adjustments made as necessary. This process is commonly called “Model Calibration”.

During the verification procedure, it is essential to model existing conditions as closely as possible to achieve a more accurate result. Key data that is monitored includes:

- New loads added to the system.
- Large customer loads
- Interruptible loads
- Up-to-date Graphical Information Systems (e.g., maps) data to capture all new main installation and replacements.
- Off-normal operating conditions, such as a valve closure or a regulator pressure adjustment (noted in the “Clearance” database)
- Production at the Propane-Air Plant

Verification results are used in defining/validating the peak design criteria used by Springs Utilities for managing the system.

9.3 PLANNING CRITERIA

Considering various operating pressures throughout the natural gas system (ranging from 2 psig to 76 psig pressure districts, and the 150 psig MAOP backbone), Gas Planning and Design has defined minimum pressure criteria for planning purposes needed to maintain reliable service to customer locations. Model results that fall below these criteria are reviewed for improvement. The table below shows the minimum supply pressure at the inlet to the regulator at the customer meter, as established by Gas Planning and Design. Minimum Supply Pressure Planning Criteria are shown in Table 9-1. These minimum pressures will ensure deliverability as natural gas exits the distribution mains and travels through service lines to a customer’s meter.

Table 9-1: Minimum Supply Pressure Planning Criteria

Minimum Supply Pressure Planning criteria	
Pressure District	**Minimum Pressure**
Water Column (Inches WC)	18" water column
Greater than 34 psig	10 psig

9.4 DETERMINING PRESSURE DISTRICT MAXIMUM CAPACITY

Using the constructed model, a detailed assessment is conducted for each of the pressure districts. The heat load is increased beyond the peak-hour load until the pressures falls below the listed minimum pressure. At that point, the total volume of natural gas entering the system, theoretically, equals the maximum capacity before reinforcements are necessary. Thus, the difference between the maximum volume and the volume determined at the design peak-hour is the additional capacity that can be served by the distribution system as currently designed.

Since the approximate natural gas usage for the average customer is known, it can be determined how many new customers can be added to the distribution system before system reinforcements are needed. The model and procedures are used with new construction proposals and/or mainline reinforcements to determine potential projects needed to maintain the integrity of the gas distribution system.

9.5 LOAD FORECASTING

Load growth and expansion forecasting (master planning) is performed to predict the distribution system's behavior and reinforcements necessary within the next ten years. System reinforcements and expansions are evaluated with the network model. A major factor impacting the ability of the distribution system to accommodate load growth and expansion is the geographic location of the load on the distribution system. Springs Utilities partners with a variety of community organizations to predict load growth, such as Pikes Peak Area Council of Governments (PPACG) Small Area Growth Forecast, the approved Springs Utilities Corporate Annual Sales and Load Forecast, and land developer's master planning proposals. This results in a distribution planning forecast that is highly beneficial in preparing budget forecasts as a part of critical infrastructure planning efforts.

9.6 NEW GROWTH

Master plan models are created for full build-out of new developments, laying out the pipe sizes and materials, along with any regulator stations that may be needed. Line extensions serving new developments are funded in advance, either by the developer or by Springs Utilities as determined by a feasibility analysis under Springs Utilities Tariff provisions. Some major new master planned developments that are likely to see growth in the next ten years include Banning Lewis Ranch, Rolling Hills Ranch, Santa Fe Springs and potential service territory annexations.

9.7 REINFORCEMENTS

Some future distribution system reinforcements will be needed as new customers are added or existing customers expand their load.

- The McClintock Gate Station capacity will need to be expanded in the next two years to support load growth in the northeast side of the gas service territory.
- Some distribution system 150P system reinforcements may be needed to serve new gas fired power generation units depending on their location on the system.
- There may be some 150P reinforcements that would benefit expanding the capacity of the existing Propane Air Plant.
- Future annexations may also drive the need for system reinforcements.

If major load expansions are needed due to infill development, they will be evaluated as they materialize.

9.8 DISTRIBUTION SYSTEM ENHANCEMENTS

Demand studies enable Springs Utilities to model numerous “what if” demand forecasting scenarios, constraint identification, and the corresponding optimum combination of pipe modification and pressure modification solutions to maintain adequate pressures throughout the natural gas distribution system.

Distribution system enhancements do not reduce demand, nor do they create additional supply. However, they can increase the overall capacity and performance of a distribution pipeline system while utilizing existing gate station supply points. Distribution enhancement solutions can be identified in two broad categories: mainlines (pipes) and regulator stations.

9.9 MAINLINE IMPROVEMENT TECHNIQUES

Techniques used to plan mainline improvements include looping, upsizing, and uprating are as follows:

9.9.1 Looping

Mainline looping is the most common method of increasing capacity within an existing distribution system. This involves constructing a new pipe parallel to an existing mainline that has, or may become, a constraint point. Constraint points inhibit volume and pressure levels downstream of the constraint, creating inadequate pressure to serve customers during high demand periods. When the parallel line is connected to the system, this second alternative path allows natural gas flow to bypass the original constraint point and bolster downstream pressure levels. The feasibility of looping a mainline is primarily dependent upon the location where the mainline will be constructed. Installing gas mainlines through private easements, residential areas, existing asphalt, and steep or rocky terrain can greatly increase the costs, compared to alternative solutions.

9.9.2 Upsizing

Mainline upsizing is simply replacing existing pipe with a larger diameter pipe resulting in a lower pressure drop. This option is usually pursued when there is damaged pipe or when pipe integrity issues exist. If the existing pipe is otherwise in satisfactory condition, looping is usually pursued, allowing the existing pipe to remain in use.

9.9.3 Uprating

Mainline uprating involves increasing the maximum allowable operating pressure (MAOP) of an existing mainline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional system facilities. However, safety considerations and pipeline regulations may limit the feasibility or lengthen the time before uprating can be completed. Also, increasing line pressure may produce leaks or other mainline damage, creating unanticipated costly repairs.

9.10 REGULATOR STATIONS

Regulator stations are used to supply a reduced pressure to an existing pressure district or new pressure district. Regulator stations are usually fed from the 150 psig MAOP system and supply additional capacity to existing or new districts. Operating pressures of an established or new pressure district are determined by the maximum allowable operating pressure established in accordance with the Department of Transportation's pipeline safety regulations. For new districts, the maximum allowable operating pressure is 76 psig or less, which allows the use of polyethylene pipe materials throughout the district. Adding a regulator station to a pressure district increases the capacity of that district. This option is limited by the availability of a higher-pressure gas source from the 150 psig MAOP system.

9.11 RISKS AND MITIGATION

Multiple delivery capacity scenarios of system events were modeled to stress test Springs Utilities distribution system. The capacity margin was selected as the condition when the first customer load does not have sufficient delivery pressure, according to Springs Utilities minimum pressure criteria. Multiple scenarios were created by distinguishing various customer classes, extreme weather, and gate station failure. The scenarios were built around the following customer categories and gate stations failure assumptions:

9.11.1 Core Firm Residential and Commercial Customers

Springs Utilities is obligated by tariff to have natural gas available to these customers at all times.

9.11.2 Military Installations

United States Air Force Academy (USAFA), Fort Carson, Peterson Air Force Base (PAFB) are areas that could potentially see substantial growth. Peterson AFB is all firm service while USAFA and Fort Carson are a combination of firm and interruptible service. The distribution system is designed to serve the firm loads year-round. The distribution system cannot serve the interruptible load on peak day so that load will be curtailed on peak day.

9.11.3 Interruptible Customers

Springs Utilities is not obligated to provide natural gas to these customers at times of peak usage.

9.11.4 Birdsall and Drake Power Plants

These electric power plants are connected to, and use, Springs Utilities natural gas distribution system to help generate electricity and are served on an interruptible basis.

9.11.5 Gate Station Failure

The system has five gates: McClintock, North, South, Drennan and Security. These are the supply sources to Springs Utilities customers. Loss of a gate station could potentially limit the distribution of natural gas depending on weather conditions.

A brief discussion of the scenarios and the key results are indicated below.

9.11.5.1 Base Case

A base case was created to simulate actual capacity for a design peak-hour at a -13 °F average day. Using the model, the system is then stressed to assess a capacity margin (all gate stations on, interruptible and military customers on-line, no asphalt plant or power plant production). The results indicate that the current system will operate down to a -19 °F daily average temperature.

9.11.5.2 Birdsall Power Plant

This scenario was the same as the base case, except with two alternative conditions; (1) Birdsall Power Plant at full production (variable is average daily temperature), and (2) available capacity at -13° F daily average temperature (see Table 9-2 for the results).

9.11.5.3 Drake Power Plant

This scenario was the same as the base case, except with two alternative conditions; (1) Drake Power Plant at full production (variable is average daily temperature) and (2) available capacity at -13 °F daily average (see Table 9-2 for the results).

9.11.5.4 Birdsall *and* Drake Power Plants

This scenario was the same as the base case, except with two alternative conditions; (1) Birdsall and Drake Power Plants at full production (variable is average daily temperature) and (2) available capacity to serve both plants at a -13 °F daily average (see Table 9-2 for the results).

9.11.6 Military Load Growth

This scenario was the same as the base case, except adding load to each military installation to determine available capacity. The model indicates that load growths of 68% at USAFA, 49% at Ft. Carson, and 24% at PAFB can be supported without any modifications to the existing system, except for metering facilities.

9.11.7 Interruptible Customers

This scenario was the same as the base case, except with an increased load on Interruptible (industrial) customers. This scenario did not cause limitations on the system.

9.11.8 Gate Station Failures

Full gate station failures would be an extremely rare event, as no event has occurred in the history of Springs Utilities. Nevertheless, models were created simulating failure of the gate stations one at a time (see Table 9-3 for the results).

Power plant capacity limits and gate station capacity limits from the scenarios described above are summarized in Table 9-2.

Table 9-2: Power Plant Maximum Capacity[1]

Power Plant Capacity Limits				
Power Plant	**Total Hourly Demand (dth/hr)**	**Percent Served (-13°F Daily Average)**	**Total Hourly Demand Served (-13°F Daily Average) (dth/hr)**	**Temperature Where 100% Served (°F)**
Drake 6&7	2,240	7.6%	170	0
Drake Aeroderivative	1,701	10%	170	-2
Birdsall	735	100%	735	-13
Drake 6&7 and Birdsall	2,975	11.4%	735	2
Drake Aero and Birdsall	2,436	13.9%	735	0

[1] Either power plant running on natural gas at 100% capacity restricts heating load on the system.

Table 9-3: Gate Station Capacity Limits[2]

Gate Station Capacity Limits				
Gate Station	**2020 Total System Hourly Demand (dth/hr)**	**Percent of Total Served by Other Four Gates (-13°F Daily Average)**	**Total System Hourly Demand Served (-13°F Daily Average) (dth/hr)**	**Temperature Where 100% Served (°F)**
McClintock off	14,349	30.0%	4,299	50
North off	14,349	53.3%	7,649	29
South off	14,349	88.9%	12,754	-3
Drennan off	14,349	74.4%	10,680	10
Security off	14,349	85.5%	12,275	0

9.12 CONCLUSION

Springs Utilities distribution system is constantly reviewed, especially following cold weather events, or substantial load changes from new or existing customers. The distribution system operated well during the last system record demand event of February 1, 2011, with no customer outages due to capacity constraints. System capacity expansions for new customers and load growth are forecasted and planned each year on an as needed basis.

Potential loss of the McClintock, North, South, or Drennan gate stations on an individual basis could result in restricted capabilities on the distribution system during peak-day or peak-hour conditions. The likelihood of such an event is quite low, but those scenarios will continue to be monitored for possible system improvement opportunities that would minimize the risk at a reasonable cost. In the unlikely event there is a gate station failure resulting in capacity shortages, the "Gas Curtailment Plan" will be implemented.

[2] Complete failure of any gate station, combined with extreme cold weather, would lead to restrictions on the system.

10.0 EIRP PORTFOLIO GAS CAPACITY ANALYSIS

10.1 EIRP BACKGROUND

Concurrent with the GIRP process, Springs Utilities additionally developed an Electric Integrated Resource Plan (“EIRP”). An EIRP generally follows the same process and develops a comprehensive long-term plan for the electric system. EIRP Portfolio 17 was identified as one of the portfolios and was approved as the preferred portfolio by the Utilities Board.

10.2 EIRP PORTFOLIO 17

EIRP Portfolio 17 indicates a need for 156 MW of gas-fired aeroderivative power generation beginning in 2022 to facilitate the early retirement of the Martin Drake coal-fired power plant. Portfolio 17 includes several renewable resources and battery storage, with the aeroderivative units expected to run as peaking units. The annual capacity factor of the units is estimated at 2% with a run-time of six hours per day when needed. The operating hours would be predominately summer peaking. The units would additionally need provide up to 20 MW of generation during winter months through 2023 until the North electric transmission improvements are completed.

Allowing for year-round operation on gas at the Martin Drake location would be prohibitively expensive. Because of this, the aeroderivative units will be configured for dual fuel gas/oil operation. Existing LDC contracted capacity on KM/CIG can support the units for most of the year with the exception of peak winter conditions. The units are mainly expected to operate during summer months where sufficient LDC capacity is available. With the low anticipated capacity factor and primarily summer operation, no additional capacity on the KM/CIG system is expected to be required in the near-term.

10.3 EIRP GAS ANALYSIS ASSUMPTIONS

The evaluation of EIRP Portfolio 17’s impacts on the gas system included the following assumptions:

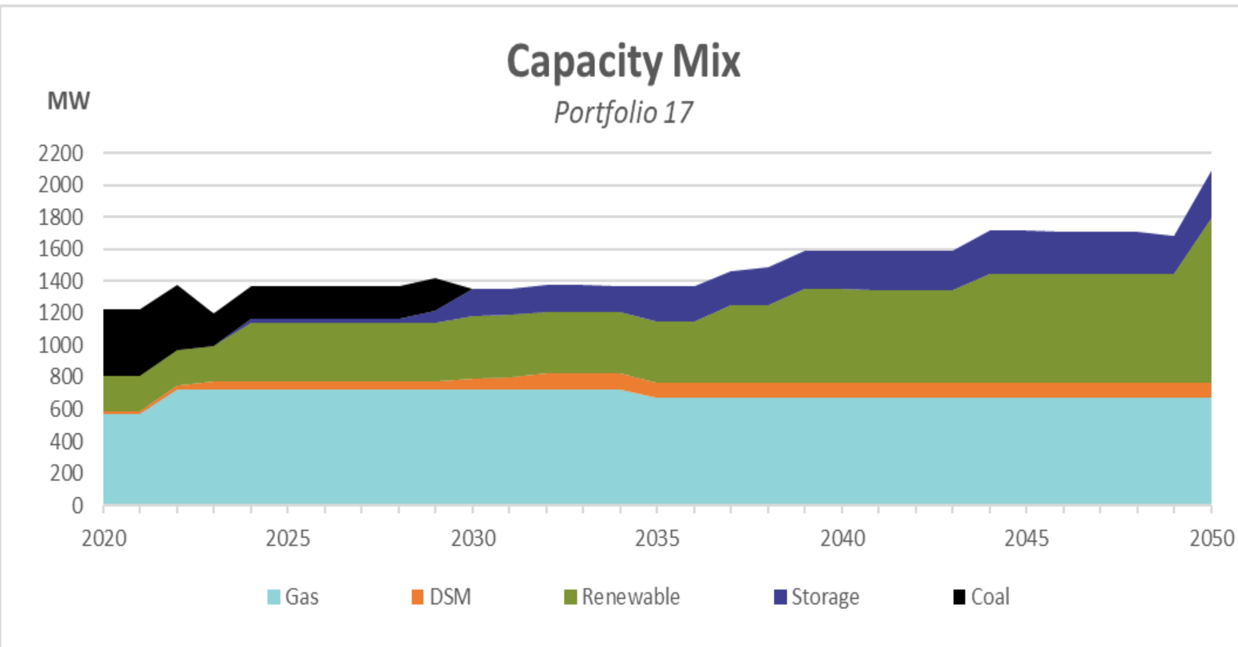
- The LDC demand forecast for 2026 at temperatures of -13, -5, 0 degrees F and in increments of 5 degrees from 5 to 50 degrees.
- Aeroderivative load was calculated for 20, 30, 60, 90, 120, 150, and 180 MW ratings using a 9,500 Btu/kWh heat rate.
- KM/CIG capacity was profiled in segments at differing times of a year considering seasonal contracts, differing peak hour multipliers, and differing storage level impacts.
- Graphical representations of the information above identified temperatures at differing times of a year where capacity would not be sufficient to support the varying unit operating levels. It was

assumed that over half of the no notice service (NNT) would be available for distributed generation needs, but some NNT capacity was reserved to cover unexpected temperature variations.

- Those temperatures were compared to 34 years of historical weather data (1996-2019) to determine the worst-case number of days by month where gas capacity would not be available along with the number of consecutive days where gas capacity would not be available. That data was used to determine the fuel oil storage levels required to support aeroderivative unit operations.
- Firm gas capacity reservation costs were estimated for varying unit operation levels and compared to potential fuel oil operational costs.

Figure 10-1 contains EIRP Portfolio 17's build plan over the study period.

Figure 10-1: EIRP Portfolio 17 Build Plan



10.3.1 Aeroderivative Unit Assumptions

The GIRP assumed unit capacity increments of 30 MW and a 9,500 Btu/kWh heat rate to develop gas supply estimates. Updated cold weather information at 20°F was obtained to estimate gas consumption estimates during winter conditions. Winter gas consumption estimates were calculated with increments of 29.7 MW and a heat rate of 9,729 Btu/kWh. Updated hot weather information at 100°F was obtained to estimate gas consumption estimates during summer conditions. Summer gas consumption estimates were calculated with increments of 25.5 MW and a heat rate of 10,067 Btu/kWh.

Table 10-1: Aeroderivative Gas Consumption Estimates

EIRP Gas Consumption Estimates							
Capacity (MW)	**20**	**30**	**60**	**90**	**120**	**150**	**180**
Heat Rate	9,500	9,500	9,500	9,500	9,500	9,500	9,500
Hourly Load (dth/hr)	190	285	570	855	1,140	1,425	1,710
Daily Load (dth/day)	4,560	6,840	13,680	20,520	27,360	34,200	41,040
Winter Gas Consumption Estimates (20°F)							
Capacity (MW)	**20**	**29.7**	**59.4**	**89.1**	**118.8**	**148.5**	**178.2**
Heat Rate	10,936	9,729	9,729	9,729	9,729	9,729	9,729
Hourly Load (dth/hr)	219	289	578	867	1,156	1,445	1,734
Daily Load (dth/day)	5,249	6,935	13,870	20,804	27,739	34,674	41,609
Summer Gas Consumption Estimates (100°F)							
Capacity (MW)	**20**	**25.5**	**51**	**76.5**	**102**	**127.5**	**153**
Heat Rate	10,871	10,067	10,067	10,067	10,067	10,067	10,067
Hourly Load (dth/hr)	217	257	513	770	1,027	1,284	1,540
Daily Load (dth/day)	5,218	6,161	12,322	18,483	24,644	30,805	36,966

10.4 HOURLY LOAD ANALYSIS

Another factor used to evaluate gas supply availability was the load profile of the electric system and gas distribution system. Although the system peaks for the gas and electric system occur at different times, ramping and time periods need to be considered to understand gas consumption dynamics on an hourly and daily basis. Indicative days for winter and summer periods were chosen based on gas consumption because gas availability is the limiting factor on for the aeroderivative units. Figure 10-2 contains the hourly electric load profiles for indicative winter and summer conditions. Figure 10-3 contains the gas consumption profile under the same winter and summer conditions. Note the gas load profile in the 25 to 45°F range is much different than a peak LDC day profile. Both the electric and gas load see rapid increases during peak gas hours (5:00 AM to 9:00 AM). Providing sufficient capacity for gas customers and the new aeroderivative units would require system upgrades to provide adequate hourly gas capacity during peak consumption periods. Extensive LDC reinforcements would be required, and KM/CIG would have to make substantial infrastructure expansions to provide the additional capacity required during peak consumption periods.

Figure 10-2: Hourly Electric Load Profile

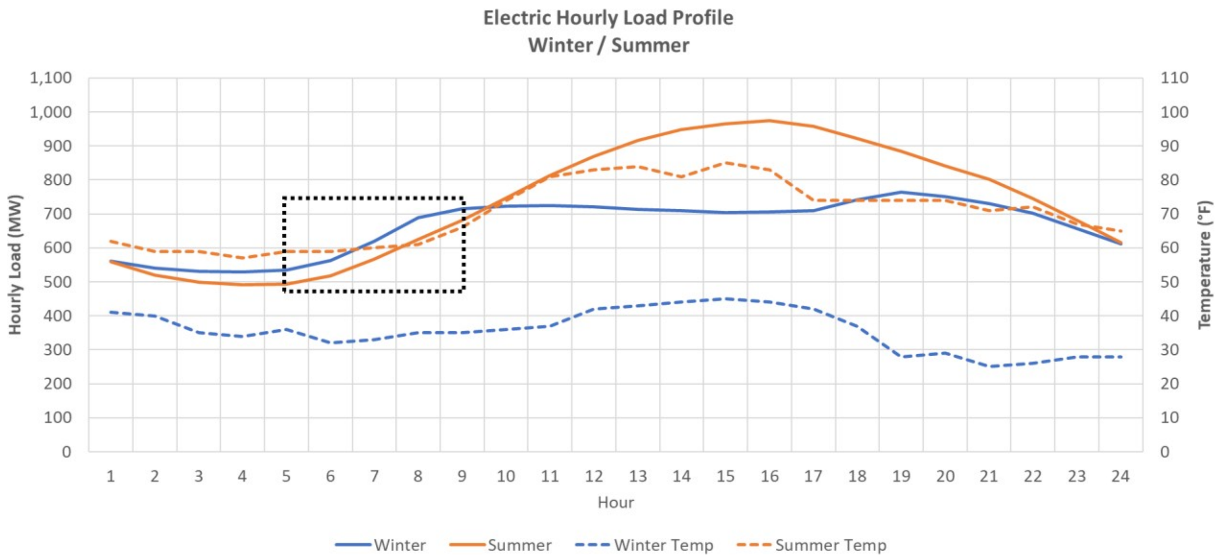
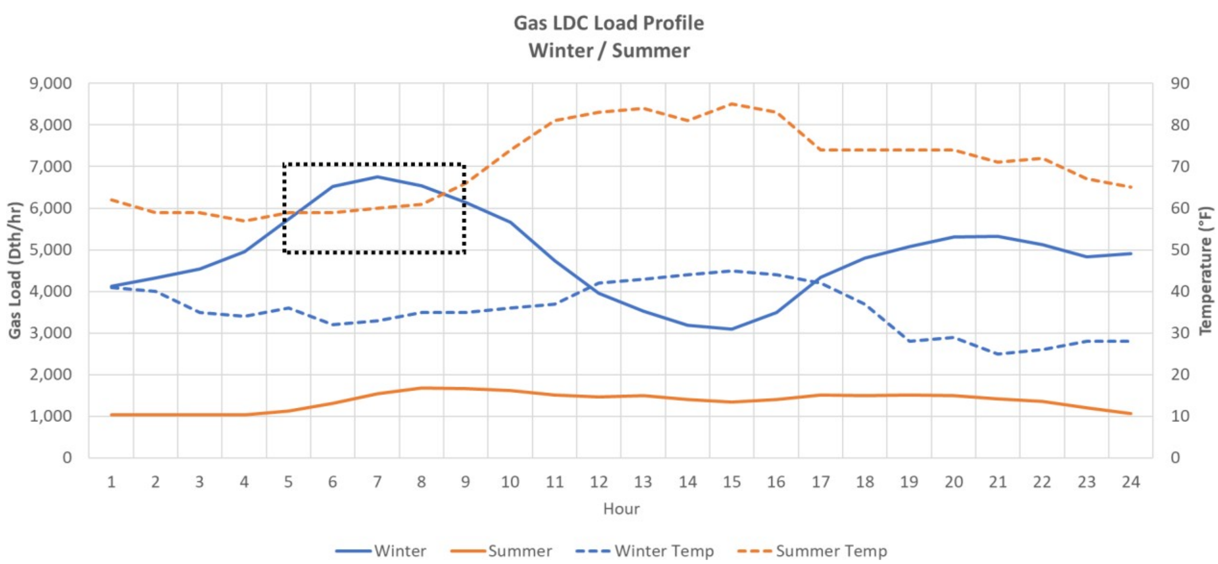


Figure 10-3: Hourly Gas LDC Profile



10.5 EXISTING GAS CAPACITY EVALUATION

Springs Utilities' existing gas resources were evaluated to determine the ability to provide the aeroderivative units with firm gas without adding additional capacity. As discussed in Section 10.4, hourly gas capacity is the main concern with gas resource due to gas consumption coinciding with significant increases in electric load during peak gas periods. Due to this, peak-hour capacity was evaluated to determine the ability to supply firm gas to the aeroderivative units. Figure 10-4 contains a comparison of existing natural gas supply resources along with the 2026 LDC load with varying levels of aeroderivative unit operation. Existing gas resources are sufficient to cover baseline LDC demand but are insufficient to serve the aeroderivative units during winter months. The system has sufficient capacity to provide the units with gas during remaining months of the year. To supply the units with firm gas during winter months, additional gas capacity would have to be procured.

Figure 10-4: 2026 Gas Capacity Availability by Season

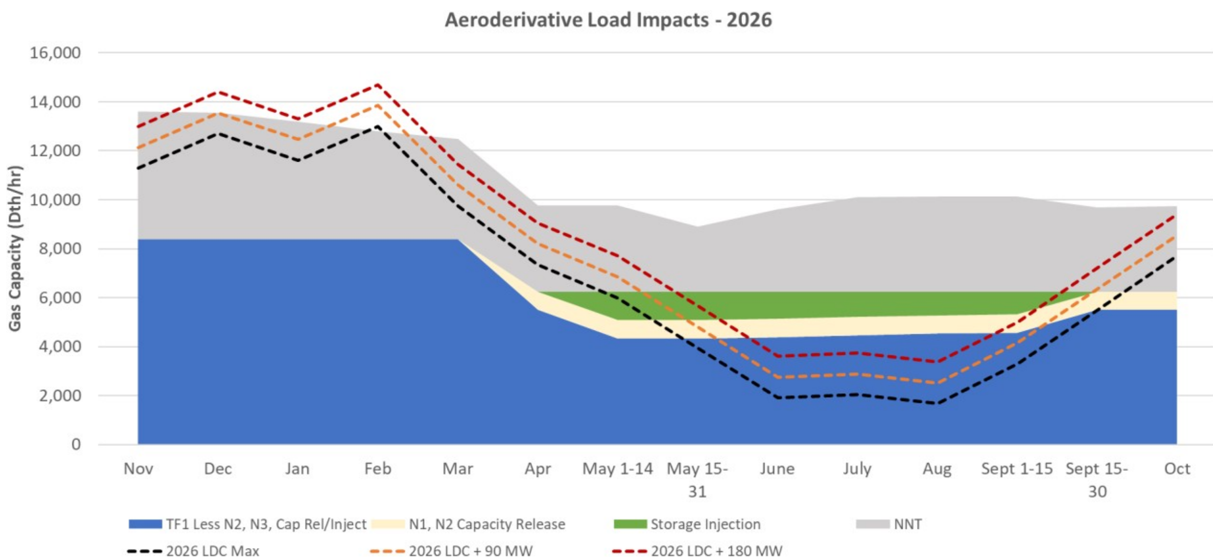
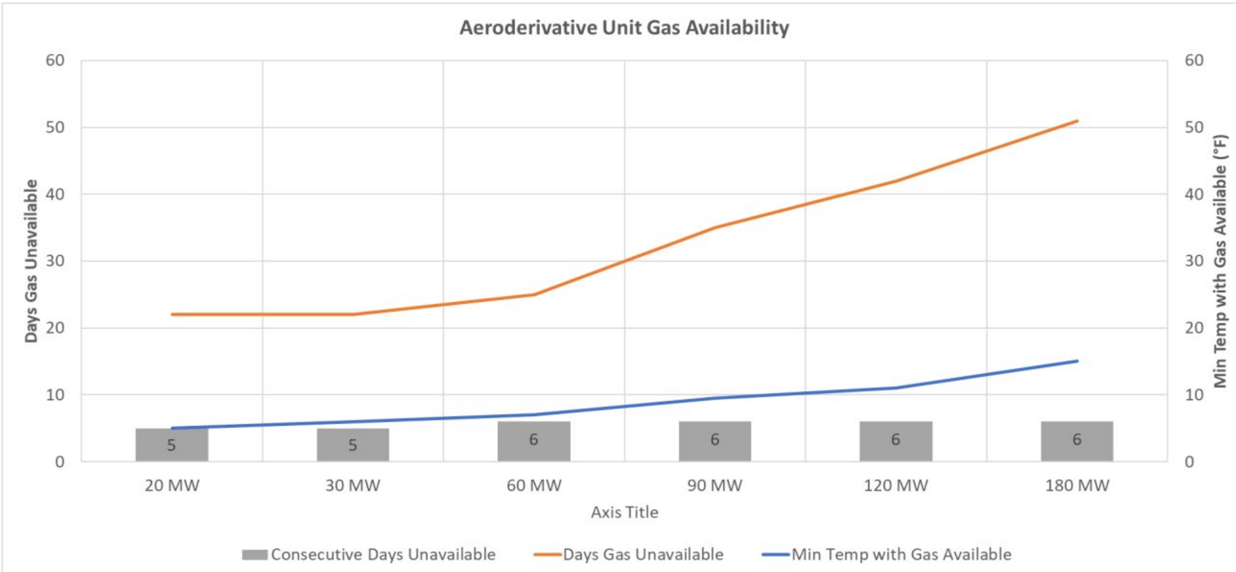


Figure 10-5 contains estimates on the number of days where gas is unavailable at various aeroderivative operating levels. The number of unavailable days significantly increases at operating levels above 60 MW. Importantly, the number of consecutive days with gas unavailable remains stable at 5 to 6 days regardless of operating level. The number of consecutive days with gas unavailable would guide the size of fuel oil storage required on site to provide sufficient fuel during extended periods with gas unavailable. This indicates that fuel oil backup would be an attractive option to allow for operation during periods of gas unavailability.

Figure 10-5: Aeroderivative Unit Gas Availability



Based on existing contracts Table 10-2 and Table 10-3 contain the estimated weather conditions and days gas is available for the aeroderivative units at various operating levels.

Table 10-2: Estimated Gas Availability 20 MW – 60 MW

	20 MW			30 MW			60 MW		
Time Period	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**
January	7	3	3	8	3	5	10	4	5
February	9	4	5	10	4	5	12	4	5
March	10	2	2	11	2	2	13	2	2
April	27	4	3	28	4	3	30	6	6
May 1-14	27	0		28	0		30	0	
May 15-31	32	0		33	0		35	0	
June	26	0		27	0		29	0	
July	23	0		24	0		26	0	
August	23	0		24	0		26	0	
Sept 1-15	23	0		24	0		26	0	
Sept 16-30	19	0		20	0		22	0	
October	19	3	3	20	3	3	22	3	3
November	5	2	2	6	2	2	7	2	2
December	5	4	4	6	4	4	7	4	4
Total	5	22	5	6	22	5	7	25	6
Days Gas Available	343			343			340		

Table 10-3: Estimated Gas Availability 90 MW – 180 MW

	90 MW			120 MW			180 MW		
Time Period	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**	**Min Temp Gas Available (°F)**	**Days Gas Unavailable**	**Consecutive Days Unavailable**
January	12	5	5	13.5	7	5	17	7	5
February	14	5	5	16	5	5	19	7	5
March	15	3	3	17	3	3	20	4	3
April	32	10	6	34	11	6	37	12	6
May 1-14	32	0		34	2	2	37	2	2
May 15-31	36.5	1	1	38	1	1	42	3	4
June	30	0		32	0		35	0	
July	28	0		29.5	0		33	0	
August	28	0		29.5	0		33	0	
Sept 1-15	28	0		29.5	0		33	0	
Sept 16-30	23.5	0		25	0		29	0	0
October	23.5	3	3	25	5	4	29	6	5
November	9.5	2	2	11	2	2	15	3	3
December	9.5	6	6	11	6	6	15	7	6
Total	9.5	35	6	11	42	6	15	51	6
Days Gas Available	330			323			314		

10.6 BREAKEVEN ANALYSIS

Springs Utilities performed an analysis to evaluate adding fuel oil backup capabilities to the aeroderivative units. Fuel oil backup could avoid or defer the need for costly gas system upgrades and thus was considered as part of Portfolio 17's analysis. The breakeven analysis evaluated the costs of operating on natural gas with the additional cost of firm gas capacity against the cost of operating on fuel oil. The analysis additionally considered various gas commodity prices to consider the impacts of varying natural gas prices. Table 10-4 includes the number of breakeven hours for the considered gas capacity options over the gas prices evaluated along with the annual fixed costs for the gas capacity options. The temporary contract option is for November through May and is not available as a long-term supply option. Across the options with additional KM/CIG gas capacity, the breakeven hours are greater than the expected number of hours where the aeroderivative units would be operating when natural gas is unavailable. In other words, the expected number of hours where firm gas capacity would be required to operate on natural gas are lower than the breakeven period. Overall, the aeroderivative units are not expected to operate frequently enough during periods with gas constraints to warrant additional firm gas capacity on KM/CIG.

Table 10-4: Aeroderivative Gas Capacity Breakeven Hours

		Break Even Hours Oil vs Gas			
Gas Supply	Gas Price ($/Dth)	30 MW	60 MW	90 MW	180 MW
LDC IT With Temporary Contract	$ 1.50	41	41	NA	NA
	$ 2.00	43	43	NA	NA
	$ 3.00	46	46	NA	NA
	$ 4.00	49	49	NA	NA
Annual Fixed Costs		$ 182,779	$ 365,559	NA	NA
LDC IT With New Capacity + New Air	$ 1.50	423	423	423	423
	$ 2.00	438	438	438	438
	$ 3.00	472	472	472	472
	$ 4.00	512	512	512	512
Annual Fixed Costs		$ 1,747,620	$ 3,495,240	$ 5,242,860	$ 10,485,720
212 Pipeline Capacity	$ 1.50	254	254	254	254
	$ 2.00	262	262	262	262
	$ 3.00	281	281	281	281
	$ 4.00	302	302	302	302
Annual Fixed Costs		$ 1,123,470	$ 2,246,940	$ 3,370,410	$ 6,740,820
212 Pipeline Capacity + NNT	$ 1.50	394	394	394	394
	$ 2.00	407	407	407	407
	$ 3.00	436	436	436	436
	$ 4.00	470	470	470	470
Fixed Costs		$ 1,745,123	$ 3,490,247	$ 5,235,370	$ 10,470,740

Notes: Temporary contract is for November through May and is not available long term
Oil Price: $2.34/Gal, $17.04/Dth
Fixed costs for Temp Contract assumed to be $2.00/Dth gas

10.7 EIRP GAS CAPACITY PLAN

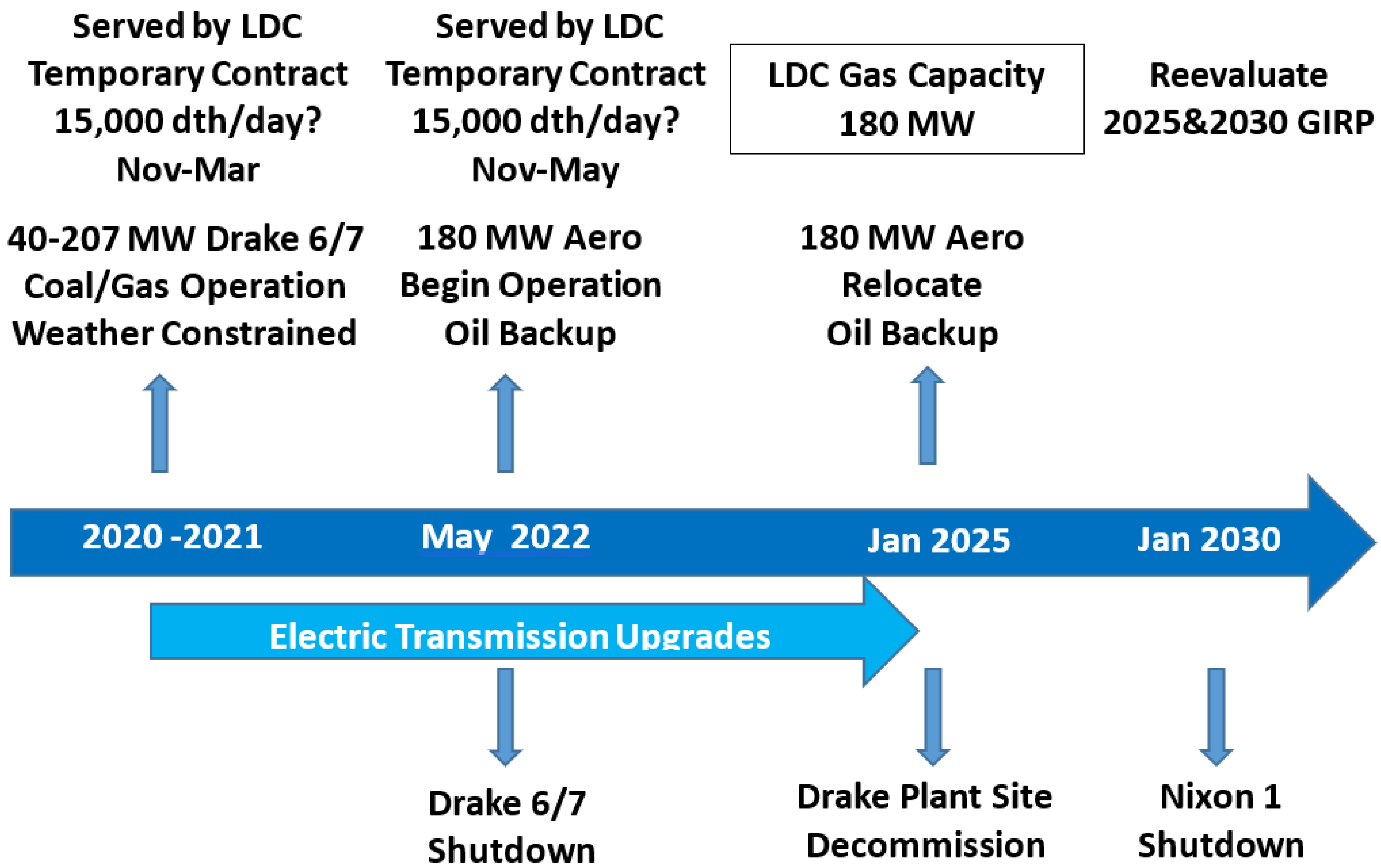
Gas capacity options for the planned aeroderivative power generators were evaluated by looking at the gas demand forecast, existing KM/CIG capacity, historical weather, planned operating conditions, and the location of the units. Consideration was also given to potential sites where the aeroderivative units could be moved from the Drake Power Plant location to other locations in Springs Utilities' service territory.

In order to obtain firm gas capacity at the Martin Drake Power Plant site, extensive LDC reinforcements would be required, and KM/CIG would have to make substantial infrastructure expansions to increase the capacity of their delivery pipeline and air injection facilities. The new units are projected to only operate at a 2% annual capacity factor and only six hours per day when needed. Additionally, the units would additionally only be operated at the Drake site for less than four years. Costly improvements required to supply firm gas to the Drake site would only be utilized for four years and subsequently leave stranded costs on the gas distribution system.

With those considerations, it was determined that the aeroderivative should be equipped with dual-fuel capability. The capital costs and annual KM/CIG capacity reservation costs to provide firm gas capacity to the Drake site could not be economically justified compared to building fuel oil backup facilities. With this capability, the aeroderivative units would be able to operate on fuel oil during peak winter periods in the event natural gas supplies are limited. Existing LDC capacity should be sufficient to supply the units with natural gas during critical summer months and partially cover operation for a large part of the year.

Figure 10-6 contains the gas capacity plan for EIRP Portfolio 17 as part of this analysis. In the short-term temporary LDC capacity would be added, the aeroderivative units would be added in May 2022 with fuel oil backup, and Martin Drake Unit 6 and 7 would be retired in 2022. The aeroderivative units will be relocated in 2025 after the completion of transmission upgrades and the Drake site will be decommissioned. At this point gas capacity requirements will be reevaluated in the 2025 GIRP.

Figure 10-6: EIRP Gas Capacity Plan

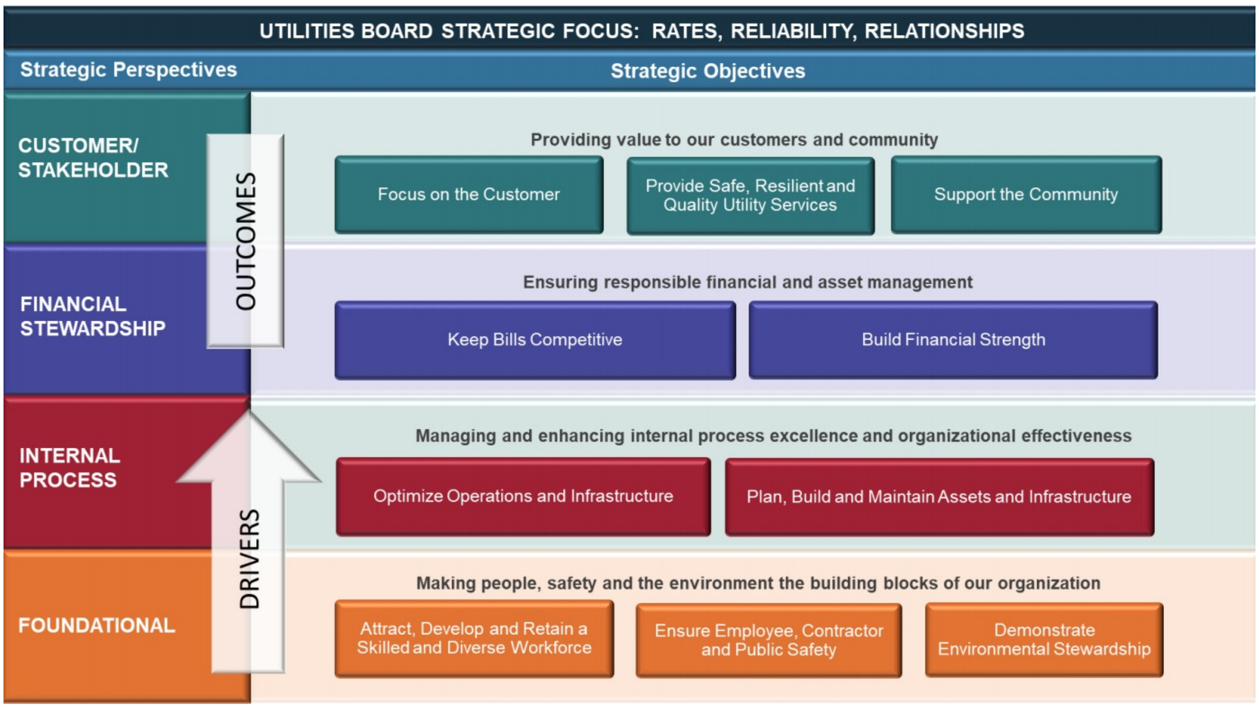


11.0 STAKEHOLDER AND PUBLIC ENGAGEMENT

11.1 OVERVIEW

Springs Utilities uses the Kaplan-Norton Balanced Scorecard Model as a basis for its strategic planning efforts. Figure 11-1 includes a visual representation of Springs Utilities' internal strategic planning efforts. As part of this model, the Strategy Map provides a visual overview of Strategic Objectives that have been identified to close performance gaps and leverage organizational strengths. The Strategy Map is read from the bottom-up, with the first two perspectives, Foundational and Internal Process, being the drivers for the Financial Stewardship and Customer/Stakeholder outcomes perspectives.

Figure 11-1: Springs Utilities Approach on Stakeholder and Customer's Engagements



11.1.1 Focus on the Customer

We take a comprehensive approach to building customer centered solutions and satisfaction for residential, commercial, and industrial customers. To achieve this, we need to:

- Anticipate and meet customer preferences
- Include customer perspectives in decisions and development
- Enhance internal and external customer relationships
- Improve customer experience, satisfaction, and loyalty
- Communicate effectively with customers through various channels
- Provide innovative customer solutions and options

- Instill and reward a culture of public service
- Be easy to do business with

11.1.2 Provide Safe, Resilient and Modern Utility Services

Being a utility that can change with the times while providing on-demand services to our customers and timely responses and information to our regulators is essential. Therefore, we have a duty to:

- Meet or exceed regulatory requirements
- Protect and secure physical assets
- Provide robust cybersecurity and information protection
- Provide reliable service
- Deliver quality products and services
- Strengthen resiliency

11.1.3 Support the Community

We contribute to the growth, vitality, and quality of life in the Pikes Peak Region. To accomplish this, we must:

- Collaborate with city and regional governments
- Promote transparent decision making
- Engage community stakeholders
- Build and maintain utility industry relationships
- Support economic growth

11.2 APPROACH TO MEETINGS AND WORKSHOPS

Below are the summery of public outreach, meetings and workshops help in 2019 and 2020.

11.2.1 Public Comment Summary

- 606 emails were sent to energyvision@csu.org.

11.2.2 Public Meetings and Workshops

- April 18, 2019 – Energy Vision Open House at Leon Young Service Center
- April 18, 2019 – Business Users Group
- August 28, 2019 – Public Workshop at Mesa Conservation Center
- October 31, 2019 – Business Customers Workshop
- January 29, 2020 – Public Workshop at Library 21C
- May 14, 2020 – Telephone Town Hall

11.2.3 Public Events

- Wagon Trail Recreation Association
- Chapel Hills Safety Day

- Smart Home "Ask the Experts" Day
- Compassion International Wellness Fair
- Home Depot Safety Event
- Swerdfeger Construction
- UCCS Cool Science Carnival
- Fort Carson Safety Expo

11.2.4 Public Presentations

- Sustainability in Progress
- City of Manitou Springs City Council Workshop
- Downtown Rotary Meeting
- Pikes Peak Construction Specifications Institute
- Downtown Partnership Board of Directors
- Manitou Springs City Council
- Leadership Pikes Peak
- Watergy

Figure 11-2: Approach to Connect with Customers

11.2.5 Quad Youth Outreach

Colorado Springs Utilities kept an engagement with the youth (ages 14-18) to get their opinion on the future of the energy industry. The results of surveys happened in 38 high schools are summarized below in Figure 11-3 and Figure 11-4.

Figure 11-3: Demographics and per school count on the youth community outreach.

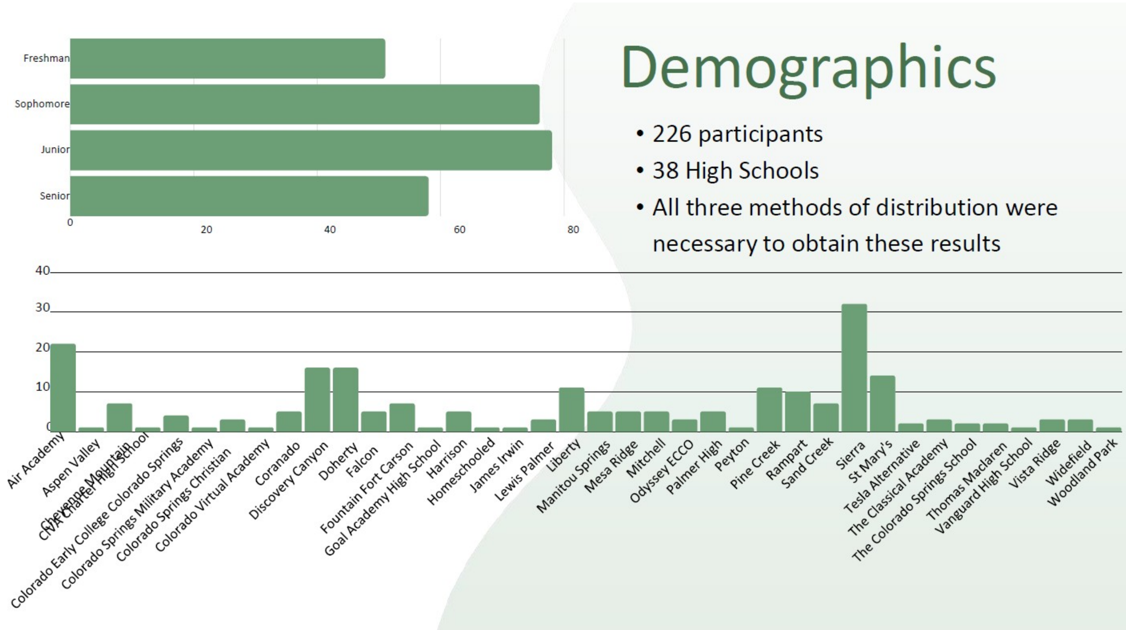
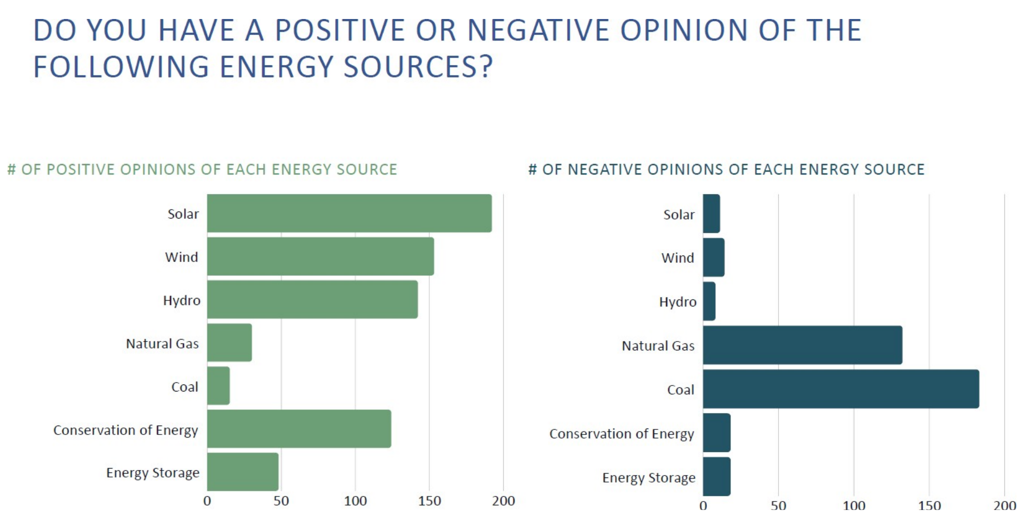


Figure 11-4: Youth community outreach response statistics to the following question:



11.3 LIST OF STAKEHOLDERS

A list of the primary external stakeholders consulted during the GIRP process is included in Table 11-1 and a list of the primary internal stakeholders is included in Table 11-2.

Table 11-1: GIRP External Stakeholders

Primary GIRP External Stakeholders
Colorado Springs Utilities Natural Gas Customers:
o Residential
o Commercial
o Industrial
o Military
o Transport
Prospective Customers
Economic Development Corporation
Chamber of Commerce
Housing & Building Association
Land Developers
Gas/Propane Suppliers
Kinder Morgan/Colorado Interstate Gas
Pipeline Construction Contractors
Heating Contractors
Equipment/Materials Suppliers
Colorado Springs City Government
El Paso County Government
Communities adjacent to Colorado Springs

Table 11-2: GIRP Internal Stakeholders

Primary GIRP Internal Stakeholders
Colorado Springs Utilities Board
Colorado Springs Utilities CEO
Colorado Springs Utilities Division Organizations:
• Environmental
• Energy Services
○ Fuels and Purchased Power
○ Operations Engineering
○ Power Plant Management
○ Gas Control Operations
○ Gas Instrumentation and Control
○ Remote Energy Plants (Propane Air)
• Energy Planning & Projects
○ Energy Planning & Innovation
▪ Energy Planning
▪ Gas Planning & Design
▪ Electric Planning
▪ DSM and Distributed Energy Strategies
○ Engineering
○ Project Management
○ System Extensions
• Planning & Finance
○ Financial Forecasting and Reporting
▪ Corporate Economist
○ Financial Planning & Pricing
• Customer and Corporate Services
○ Business Account Management
○ Government Affairs
○ Public Affairs (Corporate Communications)

11.4 SUMMARY OF PUBLIC INPUT

11.4.1 Residential Customers

- Preferred Pathway: New Renewable Resources
  Environmental Goals and New Energy Resources chosen in three pathways as the influence
- Chosen pathway bill impact: 26% not willing to accept an increase; 22% willing to accept $15 or more
- Emissions Approach: Moderate
  DSM responsibility: Individuals at 40%

11.4.2 Commercial Customers

- Preferred Pathway: New Renewable Resources
- Chosen Pathway Bill Impact: 39% not willing to accept an increase; 13% 10% or more
- Emissions Approach: Moderate
- DSM Responsibility: Individuals at 37%

11.4.3 Youth Outreach

- Students are overwhelmingly concerned with environmental issues
- Students understand the nuances and complexities of energy planning

12.0 30 YEAR ACTION PLAN

As shown in the previous chapters, due largely to local population growth, the customer demand for natural gas in the Springs Utilities coverage area will exceed current KM/CIG pipeline and Springs Utilities propane air capacity starting in the 2032-2033 heating season. The 2020 GIRP evaluated resource options needed to meet annual, peak day and peak hour customer demands forecasted through year 2050. The plan considers existing resources, the distribution system, electric generation, and efficiencies to produce a set of potential resource options that are tailored for the specific Colorado Springs Utilities requirements in specific time frames going forward.

The GIRP core team employed rigorous technical analysis to ensure safe, reliable, and cost-effective natural gas supply. A multi-discipline project team evaluated possible options (see Chapter 5 – Supply-Side Analysis and Chapter 6 – Demand-Side Management) to the upcoming supply shortfalls and recommended good solutions for detailed analysis and implementation.

Options to be developed further for implementation within this GIRP cycle based on GIRP Portfolio 6 include:

1. Planning to expand capacity of the existing Propane Air Plant to provide an additional 300 Dth/hr of supply capacity as early as year 2032.
2. Feasibility analysis and planning for construction of an additional Propane Air Plant to provide 650 Dth/hour (15,000 Dth/day) of capacity at a new location near the Drennan Gate Station as early as year 2034.
3. Initiate new Demand-side Management programs to create sustainable reductions in natural gas demand.

13.0 Colorado Springs Utilities Board Phase Presentations

Utilities Policy Advisory Committee Electric and Gas Integrated Resource Plans Assignment

Phase 1 Recommendations

Colorado Springs Utilities Board

September 19, 2019

Agenda

- IRP Assignment and Background
- IRP Goals and Guiding Principles
- Public Input Process
- Key Inputs
- Reference Case and Sensitivities
- Next Steps

UPAC Assignment Deliverables

Public Process Oversight

Goals, Reference Case, Inputs and Sensitivities

- Recommendation to Utilities Board (Sept) and Board approval (Oct)

Portfolio Evaluation Criteria

- Recommendation to Utilities Board (Feb) and Board approval (Mar)

Portfolio Recommendation with Metrics

- Recommendation to Utilities Board (Jun) and Board approval (Jul)

IRP Process

Portfolio Recommendation with Metrics

Q3 2020

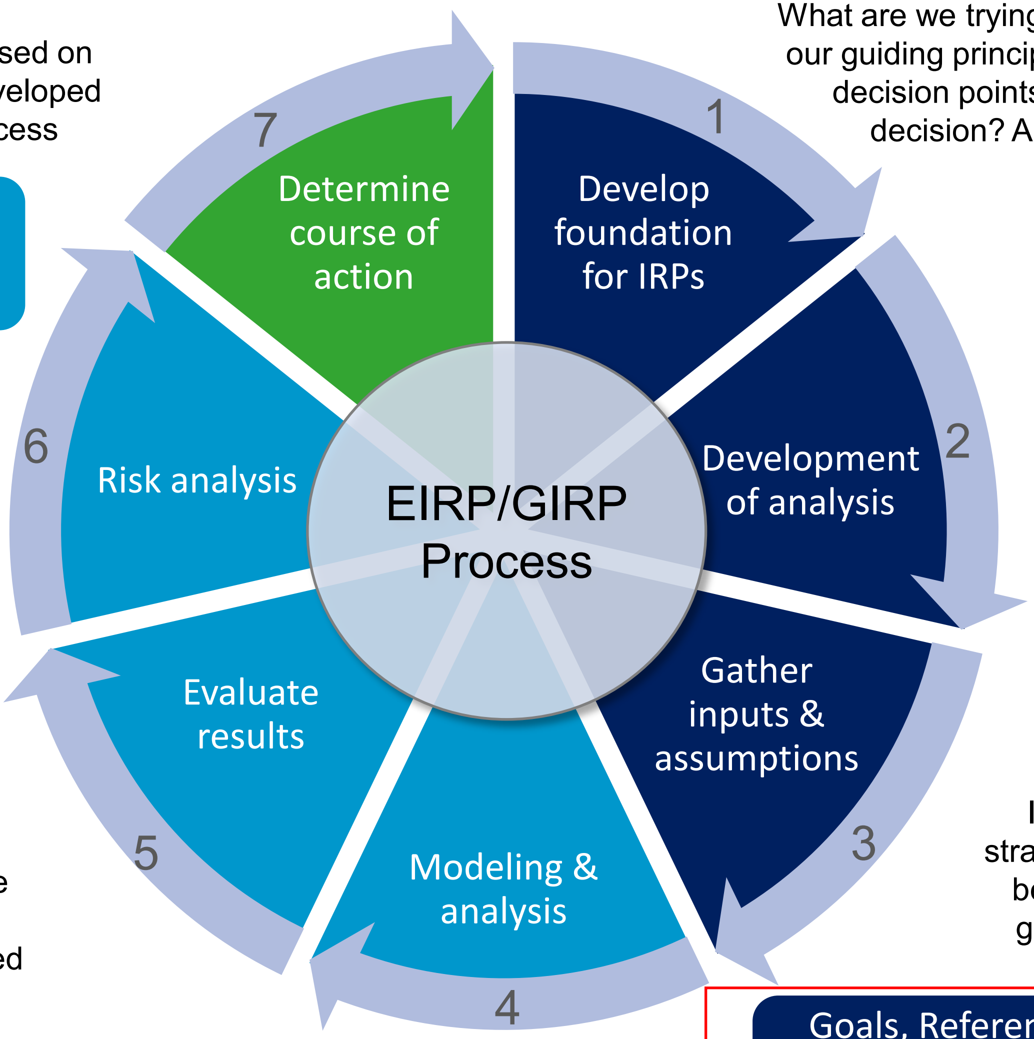
Rate portfolios based on scoring criteria developed early in the process

What are we trying to accomplish? What are our guiding principles? What are the critical decision points? How will we make a decision? Alternative resources

Q1 2020

Portfolio Evaluation Criteria

Focus in on specific plans to understand the uncertainty and impact of changes in assumptions



What is being evaluated and how will it be analyzed? Sensitivities / strategies / risk / reference case

It is critical to know the strategies and sensitivities to be considered in order to gather the correct inputs

Initial results may provide insight to additional sensitivities to be evaluated

Goals, Reference Case, Inputs and Sensitivities

Q4 2019

Energy Vision

Provide resilient, reliable and cost-effective energy that is environmentally sustainable, reduces our carbon footprint and uses proven state-of-the-art technologies to enhance our quality of life for generations to come.

Pillars of the Energy Vision

ECONOMIC

Cost-effective and equitable initiatives that drive a strong economy

ENVIRONMENT

Sustainable solutions that complement our natural resources

RESILIENCY

Reliably withstand and recover from disturbances in a dynamic environment

INNOVATION

Proactively and responsibly evolve in a transforming landscape

OUR FOUNDATION IS THE COMMUNITY WE SERVE

IRP Goals -- Developing Long-Term Plans that Align with the Energy Vision (slide 1 of 2)

Resilient and reliable

- Industry leading reliability and resiliency while avoiding potential stranded assets
- Support economic growth of the region

Cost-effective energy

- Maintain competitive and affordable rates
- Further advance energy efficiency and demand response

Environmentally sustainable

- Grow renewable portfolio
- Establish timelines for decommissioning of assets

IRP Goals -- Developing Long-Term Plans that Align with the Energy Vision (slide 2 of 2)

Reduces our carbon footprint

- Meet all environmental regulations with specific metrics that include reducing our carbon footprint
- Reduce reliance on fossil fuels

Uses proven state-of-the-art technologies

- Proactively and responsibly integrate new technologies

to enhance our quality of life for generations to come

Public Input Process

Goals

- Engage with customers in the development of the Electric and Natural Gas IRPs and planning for future energy resources for Colorado Springs.
- Provide this customer input to the Utilities Policy Advisory Committee and the Utilities Board regularly until the IRPs are approved (to occur no later than August 2020).

Objectives

- Conduct public listening sessions and engage with key stakeholders.
- Conduct surveys among residents and businesses within our community to measure public opinion of proposed IRPs.
- Leverage various communication channels to:
  - Educate customers about the new Energy Vision, Pillars, Guiding Principles and their role in the creation of the IRPs
  - Encourage community involvement in the planning process
  - Inform customers of the approved IRPs

Stakeholder Outreach – Key Groups

- Apartment Association
- Association of Realtors
- Black Chamber of Commerce
- Building Owners & Managers Assoc. (BOMA)
- City of Colorado Springs
- Colorado Springs Chamber/EDC
- Colorado Springs Forward
- Colorado Springs Leadership Institute (CSLI)
- Colorado Springs Young Professionals
- Council of Neighbors and Organizations (CONO)
- Downtown Colorado Springs Rotary
- Downtown Partnership
- Energy Resource Center
- Health Foundation
- Hispanic Chamber of Commerce
- Housing & Building Association
- Leadership Pikes Peak (LPP)
- Military Installations
    - Fort Carson
    - Peterson Air Force Base
    - United States Air Force Academy
- Neighboring Communities
    - City of Fountain
    - City of Manitou Springs
- Pikes Peak Area Council of Governments (PPACG)
- Pikes Peak Community Foundation
- Pikes Peak Small Business Development Center
- School Districts
- Sierra Club – Colorado Springs Chapter
- Student Groups
    - Colorado College
    - Pikes Peak Community College
    - University of Colorado at Colorado Springs
- Together for Colorado Springs
- Women's Chamber

Phase 1 Communications Outreach

- Paid Media
  - Print (Aug. 21 & 28)
  - Social media advertising (Aug. 12-28)
- Customer Newsletters (August)
  - Connection
  - Smart Home
  - First Source
- Social media event (August)
- Media advisory (Aug. 26)

Phase 1
Public Outreach and Comment Summary

- Comments collected from public meetings and emails
- Public Comment Summary
  - 6 emails
- Events
  - Wagon Trail Recreation Association
  - Chapel Hills Safety Day
  - Smart Home "Ask the Experts" Day
- Public Meetings
  - Sustainability in Progress
  - City of Manitou Springs City Council Workshop
  - Colorado Springs Utilities IRP Public Workshop
  - Downtown Rotary Meeting
- Results from Energy Vision public survey conducted in Spring 2019

Methodologies/Sources on Key Inputs

- **Electric Load Forecasts**
  - Historical trends: ABB Group
  - Population and economic: UCCS economic forecast
  - Modeling: Energy Information Administration (EIA), Bloomberg, Itron
- **Gas Peak Load Forecasts**
  - Regression based modeling and weather analysis
- **Demand Side Management Potential Study**
  - Cadmus
  - Baseline system loads from sector, segment, end use baseline loads
  - Customer solar photovoltaic and battery potential
- **Planning Reserve Margin**
  - General Electric
- **Gas Price Forecast**
  - ABB Group
  - Staff forecast
- **Potential Electric and Gas Resources**
  - Energy Information Administration (EIA)
  - Gas: Staff Recommendations

Definitions: Reference Case and Sensitivities

Reference Case

- Status quo with existing policies, Board directives and updated inputs
- Existing and approved assets

Sensitivities

- A change to the status quo to determine potential scenarios

Electric IRP Reference Case (draft)

Reference Case Assumptions	Methodology (Study period through 2050)
Load Forecast	Utilize Planning and Finance Department's peak demand and sales forecasts
Planning Reserve Margin	16.5%. Recommendation from reserve margin study
Commodity Price Forecast (Gas, Coal, Energy Market)	First 5 years utilizes short-term forward pricing. Fundamental forecast utilized between 2025-2050.
Energy Efficiency	1% annual energy efficiency savings/spend throughout study period. No dispatchable capacity provided beyond what's included in load forecast.
Renewables	264 Megawatt (MW) solar and 25 MW battery by 2024. Rooftop solar provides no additional capacity on peak. Integration costs from Xcel Balancing Authority.
Drake and Birdsall[1]	Retire by 2035; no selective catalytic reduction control
Nixon	No selective catalytic reduction control (will perform sensitivities around nitrogen oxides [NO_x] controls). Not retired during study period.
Front Range	No selective catalytic reduction control (will perform sensitivities around NO_x controls). Not retired during study period.
Hydro	Maintain/extend existing hydro contracts through Western Area Power Administration (WAPA)
Interruptible Customer Load	Assume 20 MW of interruptible load throughout study period
Transmission	Full transmission project to import replacement generation for Drake/Birdsall[2]

1. Replacement Generation is Gas Reciprocating Engines
2. Assumes no generation at Drake or Birdsall sites

EIRP Sensitivities (draft)

- High and low load growth
- Low cost energy efficiency
- High demand response potential
- Regional transmission organization (RTO)/Market
- High and low natural gas prices
- Plant decommission dates*
- Carbon reduction*
- Renewables*
- Military resiliency
- Low energy purchases available
- High and low renewables/battery costs
- Carbon price
- High renewable integration costs
- Extension of investment tax credit/ production tax credit (ITC/PTC)
- Higher and lower planning reserve margin
- Front Range reliability[1]

*see subsequent slides

1. Control Upgrades, isolate combustion turbine from steam turbine

Plant Decommission Sensitivities (draft)

	Decommissioning Sensitivities	Selective Catalytic Reduction
Drake/Birdsall	All units in – 2023, 2025, 2028, 2030 Birdsall Only 2025 Drake 6 only 2025	
Nixon 1	2026, 2030, 2035, 2040, 2050	2028
Front Range	2030, 2040, 2050	2028, 2038

Renewables Sensitivities (draft)

- 100% by 2030
- 100% by 2040
- 100% by 2050
- 100% by 2030 (market purchases available)
- 100% by 2040 (market purchases available)
- 100% by 2050 (market purchases available)
- 30% and 50% by 2030
- 40% and 60% by 2040
- 60% and 80% by 2050
- 100% Carbon Reduction by 2050
- 90% Carbon Reduction by 2050

Carbon Reduction Sensitivities (draft)

- 50% by 2030, 90% by 2050[1]
- 50% by 2030, 100% by 2050
- 50% by 2030, 80% by 2040, 90% by 2050
- 80%[2] by 2030, 90% by 2050
- 80% by 2030, 100% by 2050

1. State requirement. Uncertain if electric utility will have to exceed these goals
2. Intended to represent carbon reduction that includes Drake and Nixon retirement

Gas IRP Reference Case (draft)

Reference Case Assumptions	Methodology (Study period through 2050)
Load Forecast	Utilize Planning and Finance Department’s peak demand and sales forecasts
Hourly Peak Factor[1]	5.1% based on recent study conducted by gas planning
Natural Gas Price Forecast	First 5 years utilizes short-term forward pricing. Fundamental forecast utilized between 2025-2050.
Gas-fired generation	No new local distributing company (LDC) load from gas-fired generation
Interruptible Customer Load	Assume no change to prior years
Current Capacity	Assume no changes to current capacity charges (Firm, No Notice Transport (Storage), Propane Air)

1. Planning Criteria is a 1 hour in 25 year event
Design Temperature is -13F daily average

GIRP Sensitivities (draft)

- High and low load growth
- High and low gas prices
- Firm reservation cost
- Firm and non-firm capacity options
- Higher heat content fuel
- Gas demand side management potential
- Gas-fired generation sensitivities to align with EIRP capacity expansion
- Planning criteria alternatives 1-in-10 year event (vs. 1-in-25 year event)

Next Steps

October

- Board approval of IRP Phase 1
- UPAC begins IRP Phase 2

January

- Public meeting for IRP Phase 2

February

- UPAC recommendations for IRP Phase 2

March

- Board approval of IRP Phase 2

Utilities Policy Advisory Committee

Electric and Gas Integrated Resource Plans
Phase 1

Questions, Discussion

Utilities Policy Advisory Committee Electric and Gas Integrated Resource Plans

Phase 2 Recommendations

Colorado Springs Utilities Board

February 19, 2020

Utilities Board Agenda

- Review IRP Process
- Phase 1 Summary
- Phase 2 Public Process Summary
- Phase 2 Deliverable Recommendation

UPAC Assignment Deliverables

Public Process Oversight

Reference Case, Inputs, Sensitivities, and Goals

- Recommendation to Utilities Board (Sept) and Board approval (Oct)

Portfolio Attributes

- Recommendation to Utilities Board (Feb) and Board approval (Mar)

Portfolio Recommendation with Metrics

- Recommendation to Utilities Board (Jun) and Board approval (Jul)

Phase 1 Summary

Electric IRP Reference Case

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- Low cost energy efficiency
- High demand response potential
- Regional transmission organization/market
- High and low natural gas prices
- Plant decommission dates[1]
- Carbon reduction[1]
- Renewables[1]
- Military resiliency
- Low energy purchases available
- High and low renewables/battery costs
- Carbon price
- High renewable integration costs
- Extension of investment tax credit/ production tax credit
- Higher and lower planning reserve margin
- Annexations
- Front Range reliability[2]

1. See subsequent slides
2. Control Upgrades, isolate combustion turbine from steam turbine

Plant Decommission Sensitivities

	Decommissioning Sensitivities	Selective Catalytic Reduction
Drake/Birdsall	All units in – 2023, 2025, 2028, 2030 Birdsall Only 2025 Drake 6 only 2025	
Nixon 1	2026, 2030, 2035, 2040, 2050	2028
Front Range	2030, 2040, 2050	2028, 2038

SCR = Selective Catalytic Reduction

Gas IRP Reference Case

Reference Case Assumptions	Methodology (Study period through 2050)
Load Forecast	Utilize Planning and Finance Department's peak demand and sales forecasts
***Hourly Peak Factor*[1]**	5.1% based on recent study conducted by gas planning
Natural Gas Price Forecast	First 5 years utilizes short-term forward pricing. Fundamental forecast utilized between 2025-2050, from ABB 2019 Spring reference case commodity forecast
Gas-fired generation	No new local distributing company (LDC) load from gas-fired generation
Interruptible Customer Load	Assume no change to prior years
Current Capacity	Assume no changes to current capacity charges (Firm, No Notice Transport (Storage), Propane Air)

1. Planning Criteria is a 1 hour in 25 year event
Design Temperature is -13F daily average

GIRP Sensitivities

- High and low load growth
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- Higher heat content fuel
- Gas demand side management potential
- Gas-fired generation sensitivities to align with EIRP capacity expansion
- Planning criteria alternatives 1-in-10 year event (vs. 1-in-25 year event)

Phase 2
Public Process Summary

IRP Phase 2 Communications Outreach

Paid Media

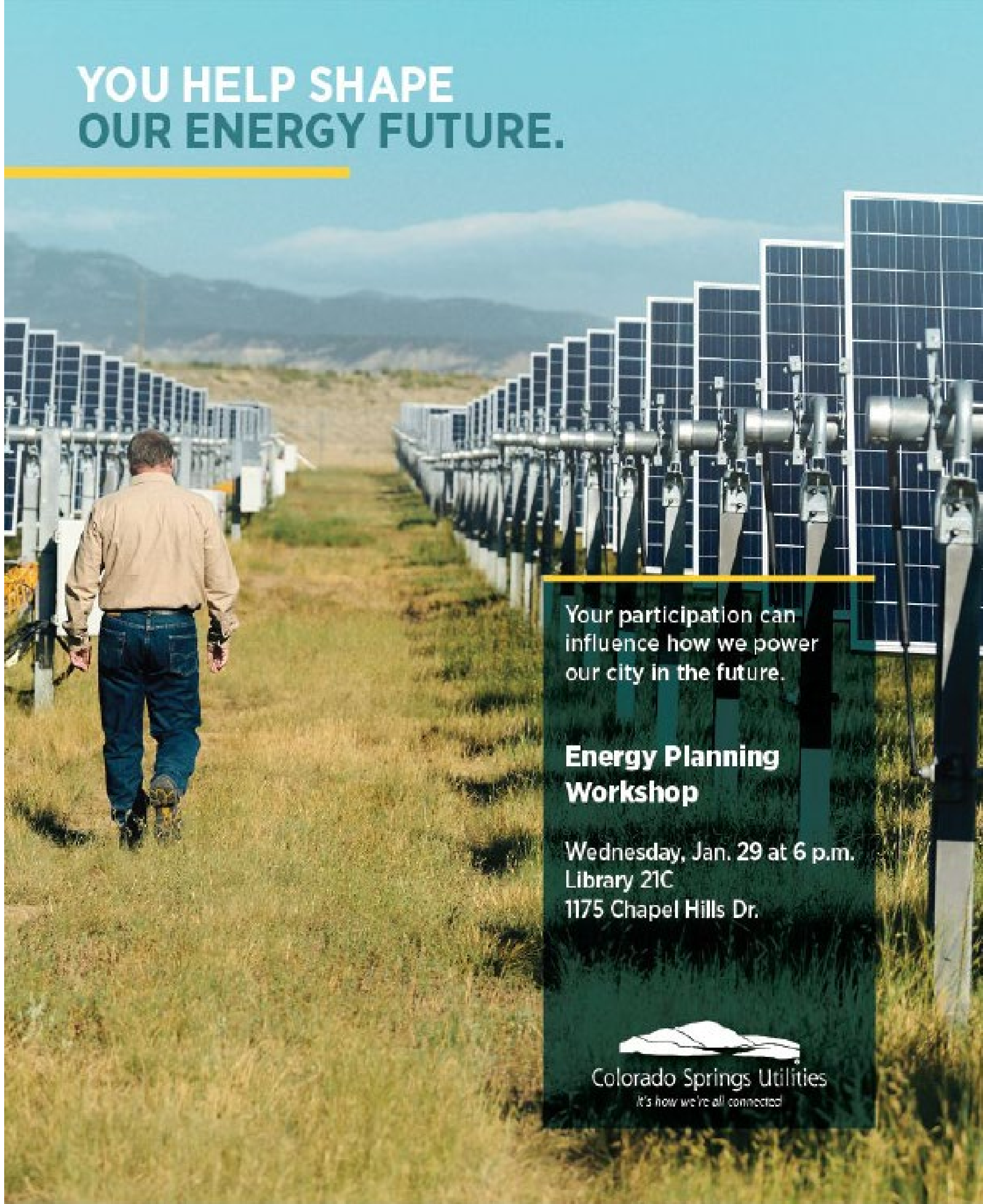
- Print (Jan. 15 & 22)
- Social media advertising (Jan. 8-29)

Newsletters (December & January)

- Connection
- Smart Home
- First Source

Social media event & posts (January)

Media advisory (Jan. 23)



Phase 2
Outreach Summary

- Public Comment Summary
  - 389 emails

- Events
  - Compassion International Wellness Fair
  - Home Depot Safety Event
  - Swerdfeger Construction
  - UCCS Cool Science Carnival
  - Fort Carson Safety Expo

- Outreach and Presentations
  - Pikes Peak Construction Specifications Institute
  - Business Customer Managed Accounts
  - QUAD Partnership Youth Outreach
  - Downtown Partnership Board of Directors
  - Manitou Springs City Council
  - Public Workshop – January 29, 2020

- Stakeholder Presentations to UPAC
  - Sierra Club Beyond Coal
  - Southeast Colorado Renewable Energy Society
  - Colorado Lung Association

IRP Phase 2
Public Comment Summary - Emails

- All public comment is provided to UPAC prior to each meeting

- Of 389 emails received at energyvision@csu.org:
  - 275 individual senders
  - “Chain” email of 170 responses

- Comments included:
  - Drake and Nixon Power Plants decommissioning in 2023/2026, including keeping lower-cost generation
  - Advocating renewable energy, primarily solar and wind
  - Concern for climate change, public health and air quality
  - Concern for capacity, rate impacts and costs moving to renewable energy
  - Inclusion of societal costs of using fossil fuels, monetizing societal costs, and concern for societal vs. renewable energy costs

Public Comment Summary
January 29 Workshop

- 172 Sign-Ins, 46 Comments Submitted
- Comments included:
  - Concern with high renewables
  - Advocate sustainability, clean air, concern for climate change
  - Close Drake or run it on natural gas
  - Utilize clean energy sources, especially solar (including on rooftops) and wind
  - Include environmental and health impacts to cost analyses
  - Use proven technology to reduce risk to ratepayers
  - Use coal for energy security
  - No certainty of costs in use of renewables
  - Use DSM/Energy Efficiency as a resource
- Attribute Comments:
  - Prioritize the environment
  - Combine innovation with flexibility/diversity

Input on Attributes

Business Customer Workshop

Key Themes:

- Concern over *cost* and what is included in *environment*
- Add *resiliency* to the attributes with *reliability*
- Desire for more mention of efficiency and DSM

Attribute Input

- Most often mentioned targets for combining with other attributes:
    - Diversity
    - Flexibility
    - Reliability
    - Stewardship
    - Innovation

Quad Youth Outreach

Key Themes:

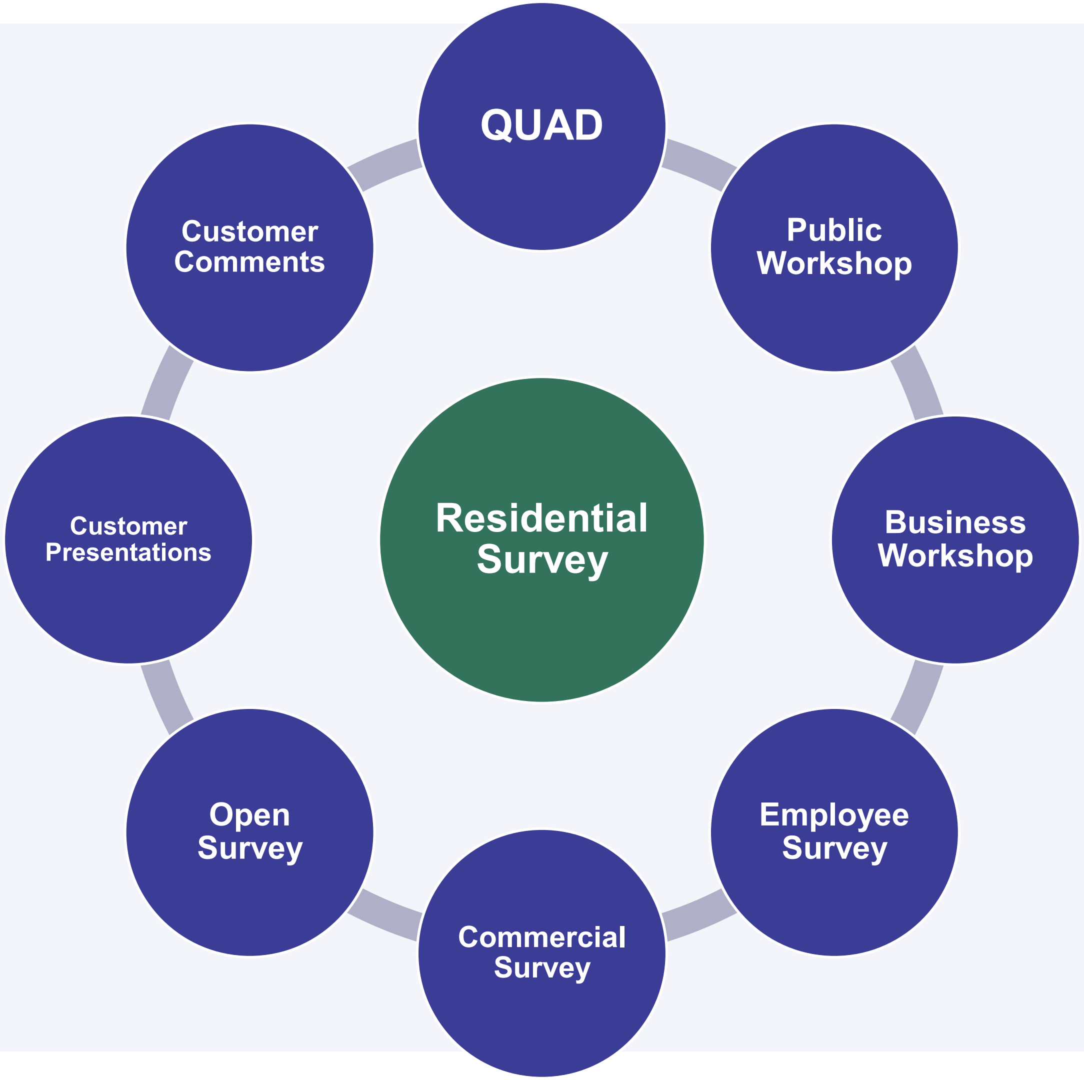
- Highest consideration given to *environment* attribute, followed by reliability and cost
- *Stewardship* had largest increase in importance after education and discussion
- Public health is an important consideration

Attribute Input

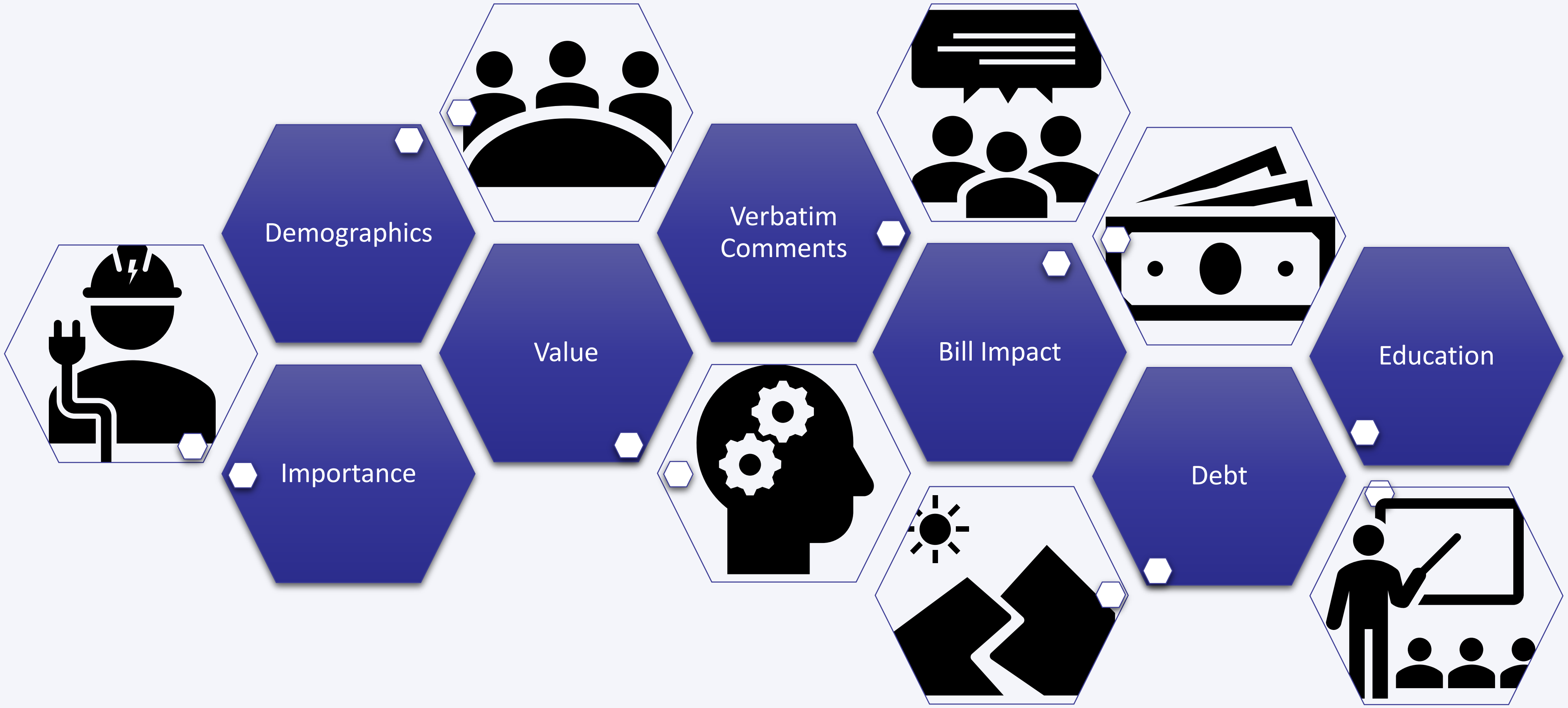
- Recommended for combining with other attributes:
    - Innovation/ Implementation
    - Reliability/Flexibility
    - Diversity/Flexibility

Survey Results

Voice of the Customer – Community Input



Survey Design



Survey Performance

- 1,918 completed surveys
- 1,824 comments reviewed

Quantitative Results
- Residential (n=619)
- Employee (n=350)

Qualitative Results
- Commercial (n=136)
- Open Web Survey (n=813)

Attributes Surveyed

Cost	Cost-effective, maintaining competitive and affordable rates, and the financial health of the utility which drives a strong economy.
Diversity	Balancing multiple types of generators and sources of fuel, including distributed generation, and reducing reliance on fossil fuels.
Environment	Sustainably grow our renewable portfolio, reduce our carbon footprint and meet all environmental regulations.
Flexibility	The ability to modify a strategy to account for regulatory and market disruptions. (e.g. Portfolio can quickly adapt to sudden change in demand.)
Innovation	Proactively and responsibly integrating technologies and programs.
Implementation	Constraints impacting the execution of a portfolio within a desired timeframe.
Reliability	The ability to react to variable or extreme daily operating conditions. (i.e. The lights stay on.)
Stewardship	Responsibly protecting and supporting quality of life now and for the future.

Key Residential Findings

- Cost, Environment, Reliability, and Stewardship were rated most important
- Cost, Environment, Reliability, and Stewardship showed to have the most value
- 39% of residential customers would resist any bill increase or up to $2
- 16% of residential customers would approve of a bill increase of $15 or more
- 49% of residential customers needed more information on the debt question

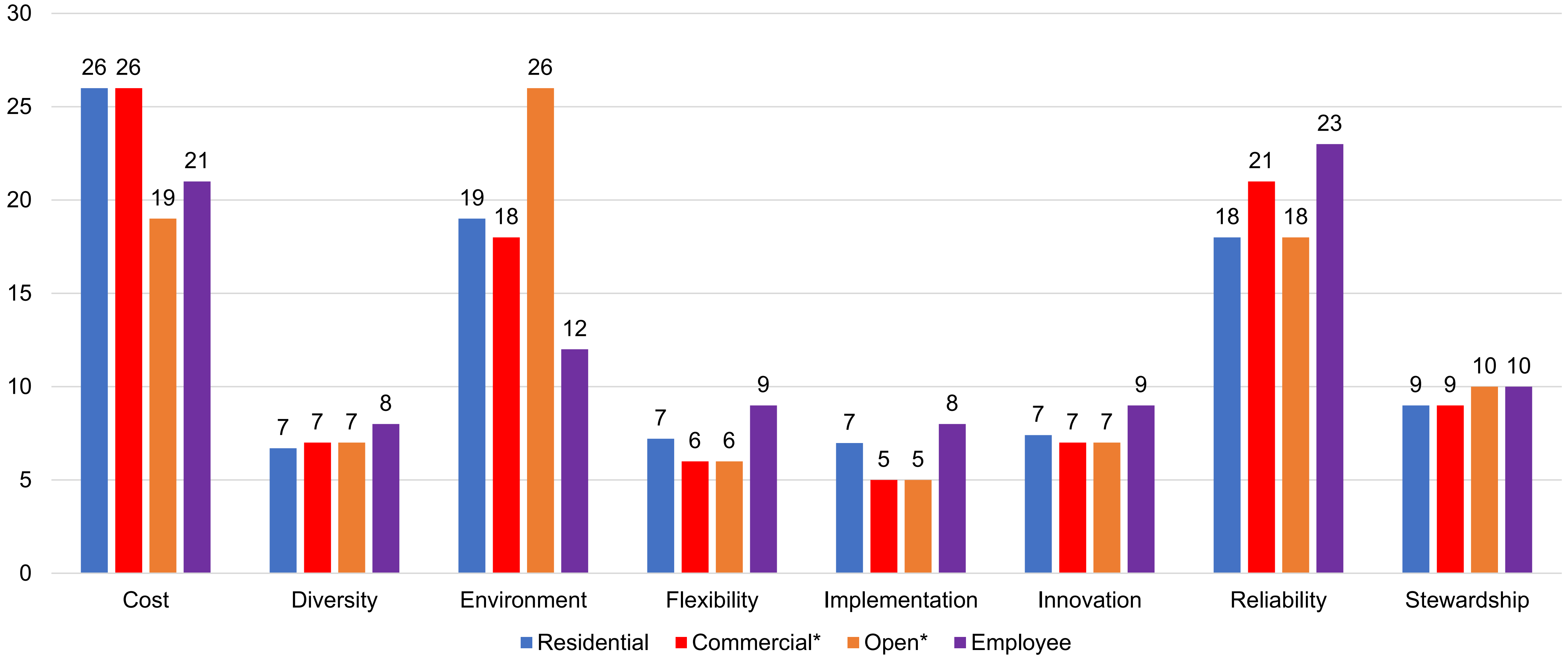
Key Findings Overall

- Top four attributes for all segments are Cost, Reliability, Environment and Stewardship
  - Residential - Focused on Cost and Reliability
  - Commercial* - Focused on Cost and Reliability
  - Employee - Focused on Reliability and Cost
  - Open* - Focused on Environment and Cost
- Diversity did not resonate on any survey

*Qualitative Results

Value Allocation By Attribute – 8

*Qualitative Results



Attribute Consolidation

- Combining related concepts
- Making measurements meaningful
- Aligning with Energy Vision pillars and goals
- Simplifying scoring process
- Considering stakeholder input

Phase 2 Attributes (5 attributes draft)

Cost	Implementation	Cost-effective, maintaining competitive and affordable rates, and the financial health of the utility which drives a strong economy while being able to execute the portfolio within a desired timeframe.
Environment	Stewardship	Sustainably grow our renewable portfolio, reduce our carbon footprint, meet all environmental regulations while responsibly protecting and supporting quality of life now and for the future.
Flexibility	Diversity	The ability to modify a strategy to account for regulatory and market disruptions through balancing multiple types of generators and sources of fuel, including distributed generation, and reducing reliance on fossil fuels.
Innovation		Proactively and responsibly integrating technologies and programs.
Reliability		The ability to react to variable or extreme daily operating conditions. (i.e. The lights stay on.)

IRP Phase 2 Recommendations

Phase 2 Recommendations Process

INPUT (Qualitative and Quantitative)

IRP Phase 1:

Reference Case, Inputs & Sensitivities

Energy Vision goals

Colorado legislation

Industry trends

Information from staff

Customer, employee & open surveys

Input at public meetings

Email comments

Stakeholder input

UPAC

Selected eight attributes

Based on public input consolidated eight attributes to five

Members individually applied weightings

Members deliberated and finalized weightings as a group

Recommend attributes and weightings to Utilities Board

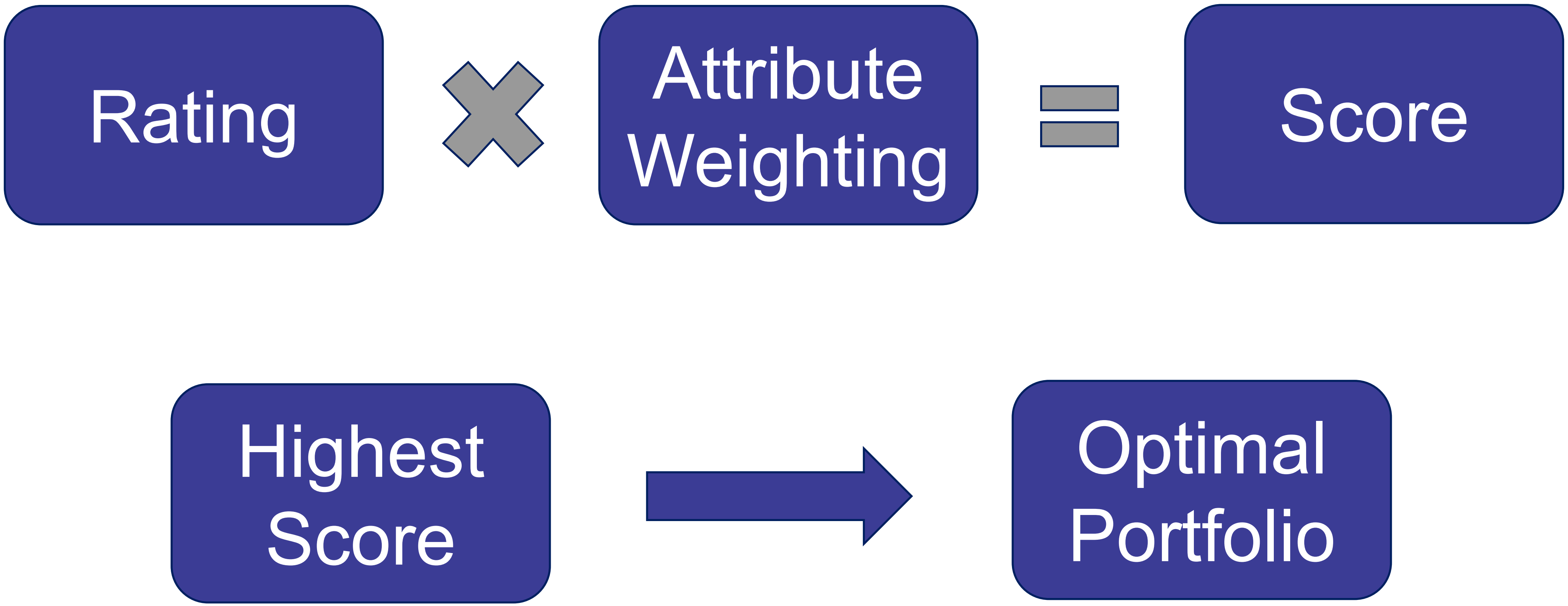
UTILITIES BOARD

Discuss and approve final attributes and weighting

Phase 2 Recommended Attributes and Weighting

Attribute	Weight
Reliability	32%
Ability to react to variable or extreme daily operating conditions (i.e., the lights stay on).	
Cost/Implementation	24%
Cost-effectively maintain competitive, affordable rates and the financial health of the utility to drive a strong economy with ability to execute portfolio in desired timeframe.	
Environment/Stewardship	22%
Sustainably grow renewable portfolio, reduce carbon footprint and meet all environmental regulations while responsibly protecting and supporting quality of life now and for the future.	
Flexibility/Diversity	14%
Ability to adapt to regulatory and market disruptions by balancing multiple types of generators and fuel sources, including distributed generation, and reduce reliance on fossil fuels.	
Innovation	8%
Proactively and responsibly integrate technologies and programs.	

Applying Attribute Weighting to Portfolios



Scoring Example

Year	Portfolio 1	
2023		
2024	25 MW Battery	150 MW Solar
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033	New Gas Supply	
2034	265 MW RECIP	
2035	Decommission Drake 6 & 7	
2036		
2037		
2038		
2039		
2040		
2041		
2042	New Gas Supply	
2043	65 MW RECIP	
2044		

Attribute	Weighting		Portfolio 1		Score
Reliability	32%	×	4	=	128
Cost / Implementation	24%	×	5	=	120
Environment / Stewardship	22%	×	1	=	22
Flexibility / Reliability	14%	×	3	=	42
Innovation	8%	×	2	=	16

Example Rating Criteria

Cost/Implementation	Score	Portfolio 1	Portfolio 2
Lowest Revenue Requirement	5		
	4		
	3		
	2		
Highest Revenue Requirement	1		

Cost/Implementation	Score	Portfolio 1	Portfolio 2
Operational lead time 1 year or less	5		
Operational lead time less than 3 years	4		
Operational lead time less than 5 years	3		
Operational lead time less than 10 years	2		
Operational lead time 10 year or more	1		

Next Steps

March

- Utilities Board approval of IRP Phase 2
- UPAC begins IRP Phase 3

April

- Public survey for IRP Phase 3

May

- Public Workshop

June

- UPAC IRP recommendations to Utilities Board

July

- Board approval of IRP

Utilities Policy Advisory Committee

Electric and Gas Integrated Resource Plans
Phase 2

Questions, Discussion

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

Electric and Gas Integrated Resource Plans

Utilities Policy Advisory Committee

June 3, 2020

Agenda

- Legislative update (for ELT only)
- Public process update
- Portfolios with Scoring, Financial Results, Sensitivities and Risks
- IRP Workshop and Workbook
- Recommendation to Utilities Board
- Finalize June Utilities Board presentation
- Next assignment for UPAC

IRP Process

Portfolio Recommendation with Metrics
Q3 2020

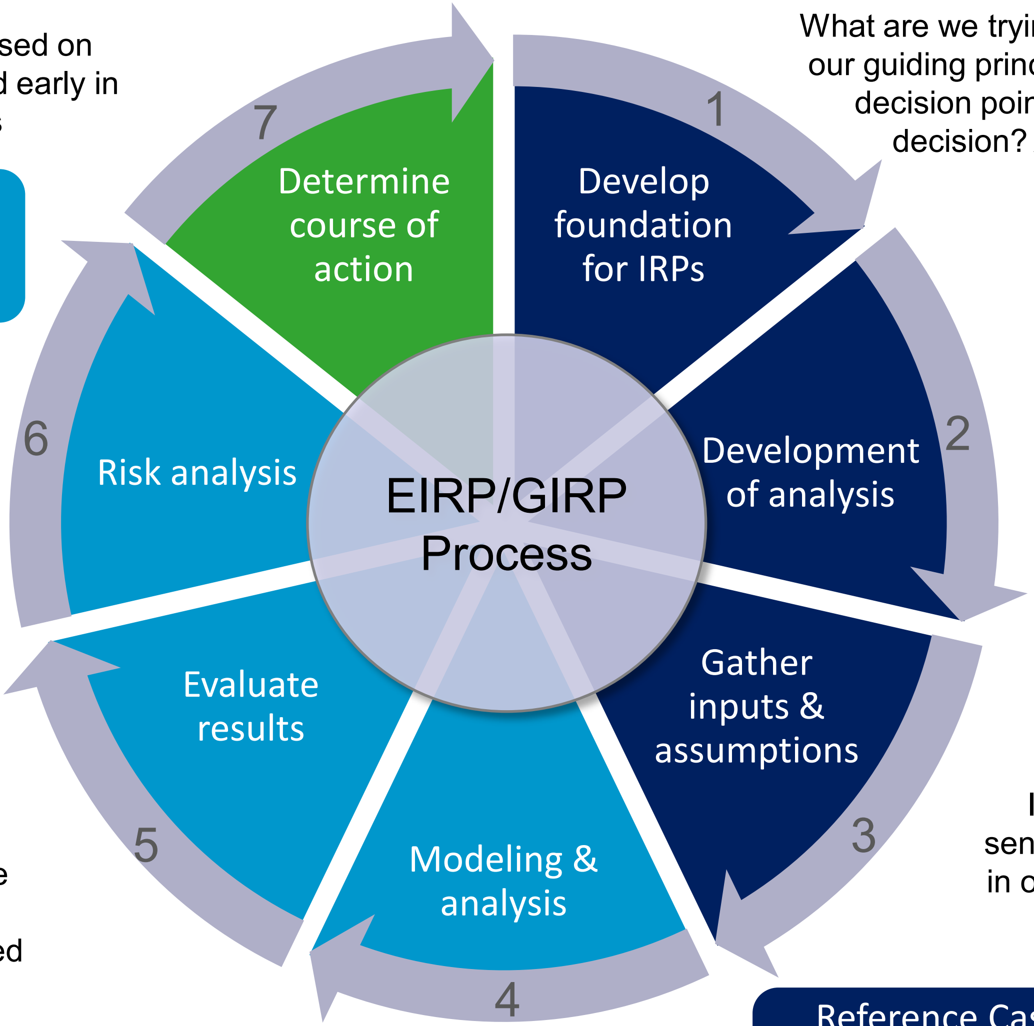
Q1 2020
Portfolio Attributes

Rate portfolios based on attributes developed early in the process

What are we trying to accomplish? What are our guiding principles? What are the critical decision points? How will we make a decision? Alternative resources

Focus in on specific plans to understand the uncertainty and impact of changes in assumptions

What is being evaluated and how will it be analyzed? Sensitivities / risk / reference case



It is critical to know the sensitivities to be considered in order to gather the correct inputs

Initial results may provide insight to additional sensitivities to be evaluated

Reference Case, Inputs, Sensitivities, and Goals
Q4 2019

Legislative update

Regulatory Landscape Coming Into Focus

CEO and CDPHE presentations to AQCC and PUC that HB19-1261 goals cannot be met without 80 x 30 emissions reductions from all Colorado generators

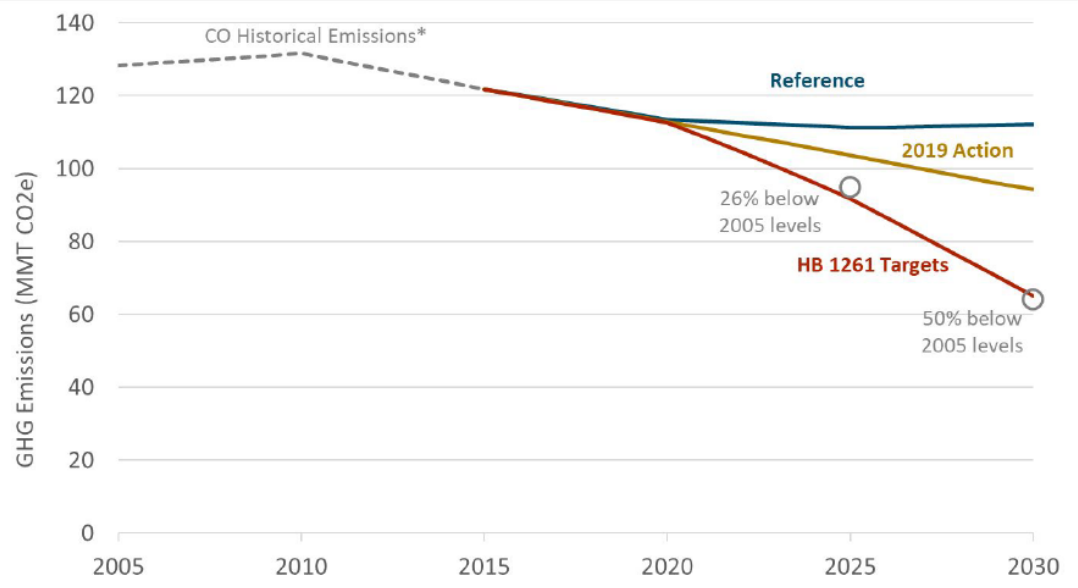
- Any scenarios that achieve 1261 targets will likely require 80%+ emissions reductions in generation by 2030…." –CEO & CDPHE presentation to the Colorado PUC on 05/11/20

Utility Peer Announcements

- Xcel: 80 x 30 / Comanche 1 & 2 (3 / Brush / Hayden?) / Must file CEP
- TSGT: 90 x 30 (gen) 70 x 30 (sales) / No coal / Will file CEP
- BHE: No coal (CACJ 2010) / Will file CEP
- PRPA: 90 x 30* / No coal* / Likely to File CEP*

Recent State Presentation Takeways

Scenarios



- ***Reference Scenario***
  - Existing policies and actions included (e.g. federal CAFE standards)
- ***2019 Action Scenario***
  - Adds recent policies (e.g. 2019 CO Legislative Session)
- ***1261 Target Scenario(s)***
  - Illustrative measures not currently in CO policy that will help the State meet GHG targets

*revised post-2005 with constant Oil & Gas emissions

COLORADO Energy Office · COLORADO Department of Public Health & Environment · COLORADO Department of Agriculture · COLORADO Department of Transportation · COLORADO Department of Natural Resources

Recent State Presentation Takeways

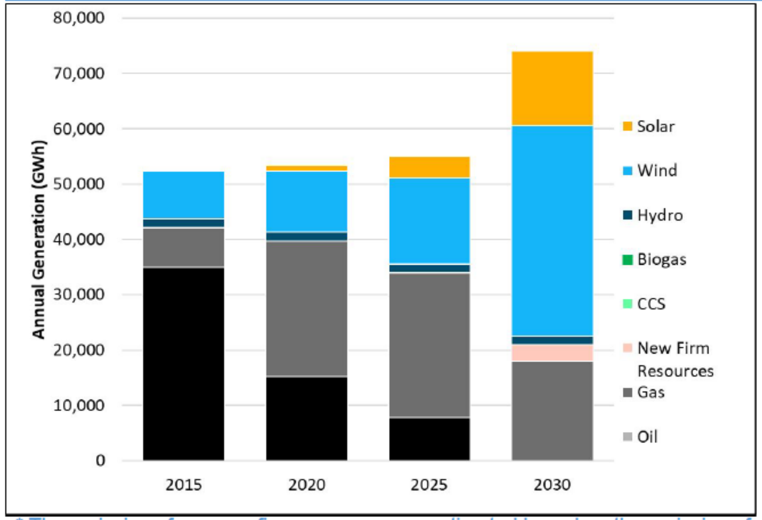
Potential Electricity Supply - HB 1261 Targets

Key Observations

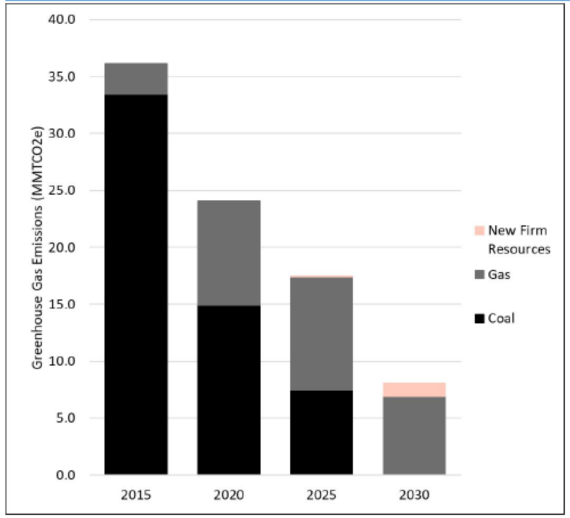
- Coal plants are retired by 2030 to meet the GHG emission reduction target
- Wind, solar, batteries, and new firm resources are added to replace coal

Metric	2025	2030
GHG Emissions (MMT)	17.5	8.1
Effective RPS (%)	40%	75%

Energy Balance (GWh)



Emissions (MMT CO2e)



* The emissions from new firm resources are estimated based on the emissions from equivalent gas plants

COLORADO Energy Office | COLORADO Department of Public Health & Environment | COLORADO Department of Agriculture | COLORADO Department of Transportation | COLORADO Department of Natural Resources

Recent State Presentation Takeways

Some key takeaways

- Electricity generation, transportation and building electrification, and energy efficiency account for more than 50% of potential 2030 reductions
- PUC has a key role through ERPs, CEPs, transportation electrification plans, beneficial electrification, and gas and electric DSM
- Any scenarios that achieve 1261 targets will likely require 80%+ emissions reductions in generation by 2030, significant utility support for transportation and building electrification, and strong utility DSM

COLORADO Energy Office | COLORADO Department of Public Health & Environment | COLORADO Department of Agriculture | COLORADO Department of Transportation | COLORADO Department of Natural Resources

Two Regulatory Paths Available

Clean Energy Plan

- Must achieve least 80 x 30
- Verified by PUC & APCD
- Ultimately approved by governing board
- “Safe harbor” through 2030

AQCC Rule Making

- Required reductions unknown, but safe to assume 80 x 30 based on input being provided
- Process will be open to entire state
- State Agencies will be reaching out to develop potential compliance scenarios (summer 2020)

CEP Advantages (Certainty)

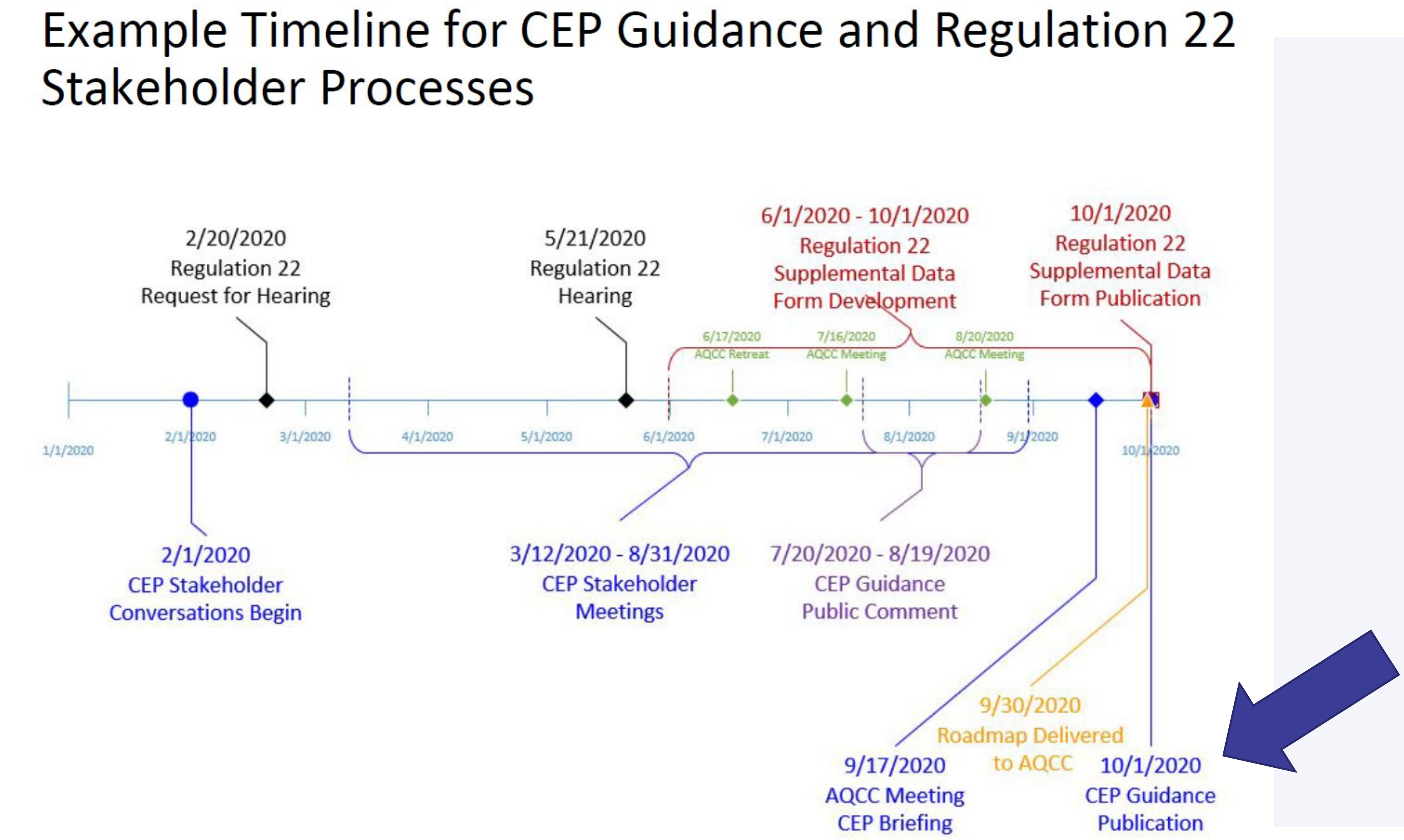
PUC

- Voluntary for MOUs
- Deemed approved if 80 x 30 jointly verified by APCD
- No additional jurisdiction
- Must account for system reliability (SB19-236)
- Max retail rate impact 1.5% (SB19-236)

AQCC / APCD

- Already crafting parameters
- <u>Shall</u> take CEP into consideration
- <u>Shall not</u>
  - Dictate mix of generation
  - Mandate additional reductions (through 2030)
  - Impose direct costs associated with remaining GHGs if CEP achieves at least 75% x 30 (through 2030)

CEP Timeline



Concluding Thoughts

What we know:

- State law requires us to reduce our GHG emissions
- Safe assumption that 80 x 30 will be our expected target
- APCD will be verifying our plan either way

What we don't know:

- What a CEP process looks like (though picture getting clearer)
- Does filing a CEP pose significant precedent issues with PUC?
- Does filing a CEP necessarily provide an advantage?
  - Is the so-called "safe harbor" safe? / What about post 2030?

Recommendation

- All of the portfolios UPAC selected in May put us on track from a policy and decision-making standpoint for meeting the 80% reduction by 2030.
- UPAC would recommend one of these portfolios (with a couple of alternates) to the Board for consideration of approval.
- We recommend expressing to the state agencies (after the Board IRP decision) that we intend to file an associated CEP, and that this would be sometime subsequent to the finalization of the associated guidance document.
- In the meantime, Environmental Services, Government Affairs and Energy Planning will continue to flesh out requirements for two compliance paths.

Public process update

Communication Outreach

IRP Phase III Public Participation

Utilities Policy Advisory Committee

- May 6
- June 3 – Finalize portfolio recommendations

Utilities Board

- June 17 – Discuss UPAC's portfolio recommendation
- June 26 - Consider approval of final portfolios

Workshop

- May 14, 6:00 pm – Public Telephone Town Hall
- June 19, Business Customer Meeting

Survey

- April 1 – May 3

Email energyvision@csu.org

Website: csu.org

Integrated Resource Plan – Next Steps External Engagement

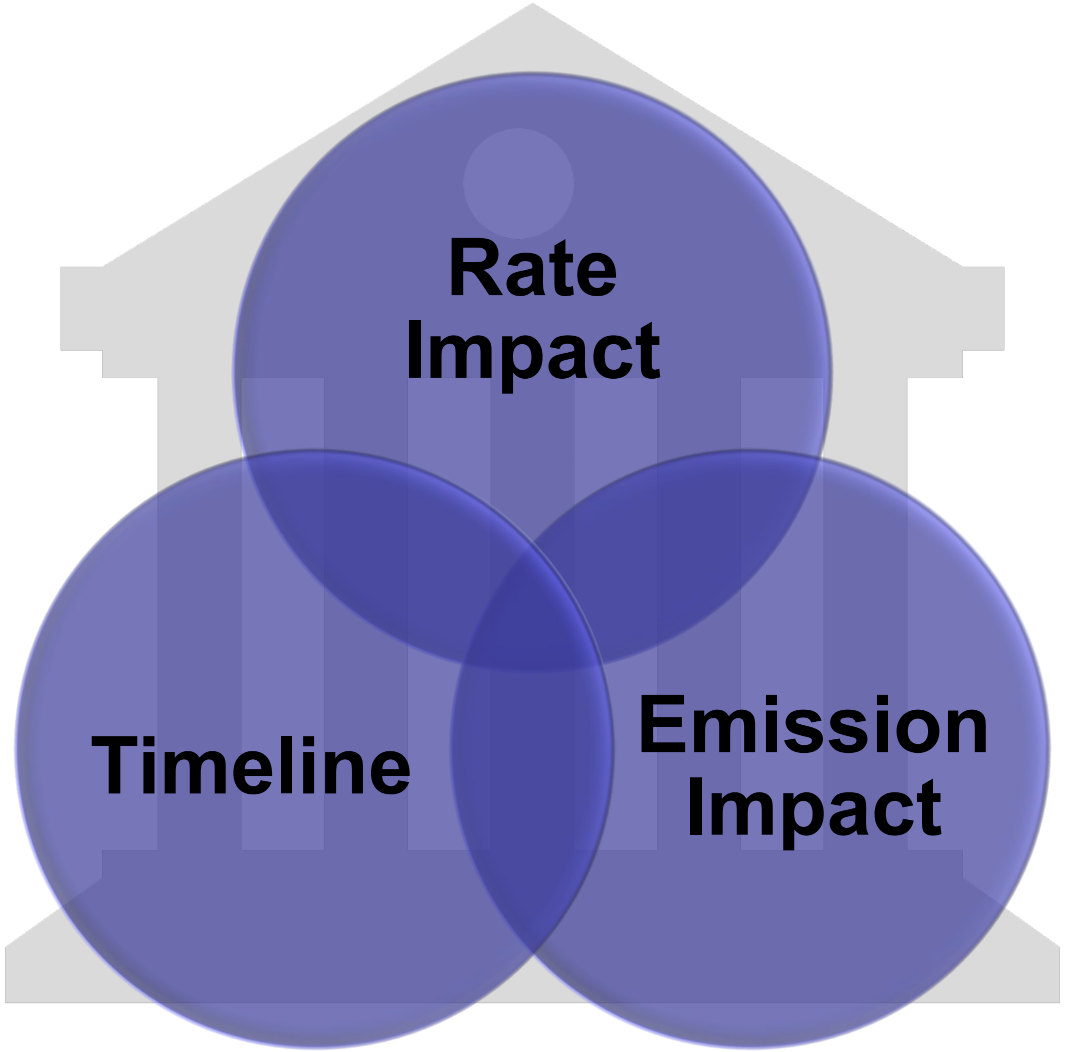
Date	Activity
June 17: 9:30am – 12pm	Joint UPAC/UB Workshop for in-depth portfolio review
June 17: 1pm	Utilities Board meeting: UPAC formally recommends portfolio
June 26: 8am – 10am	Special Utilities Board meeting: final approval of portfolio

Telephone Town Hall Summary

QUAD Youth Outreach

Survey Response Summary

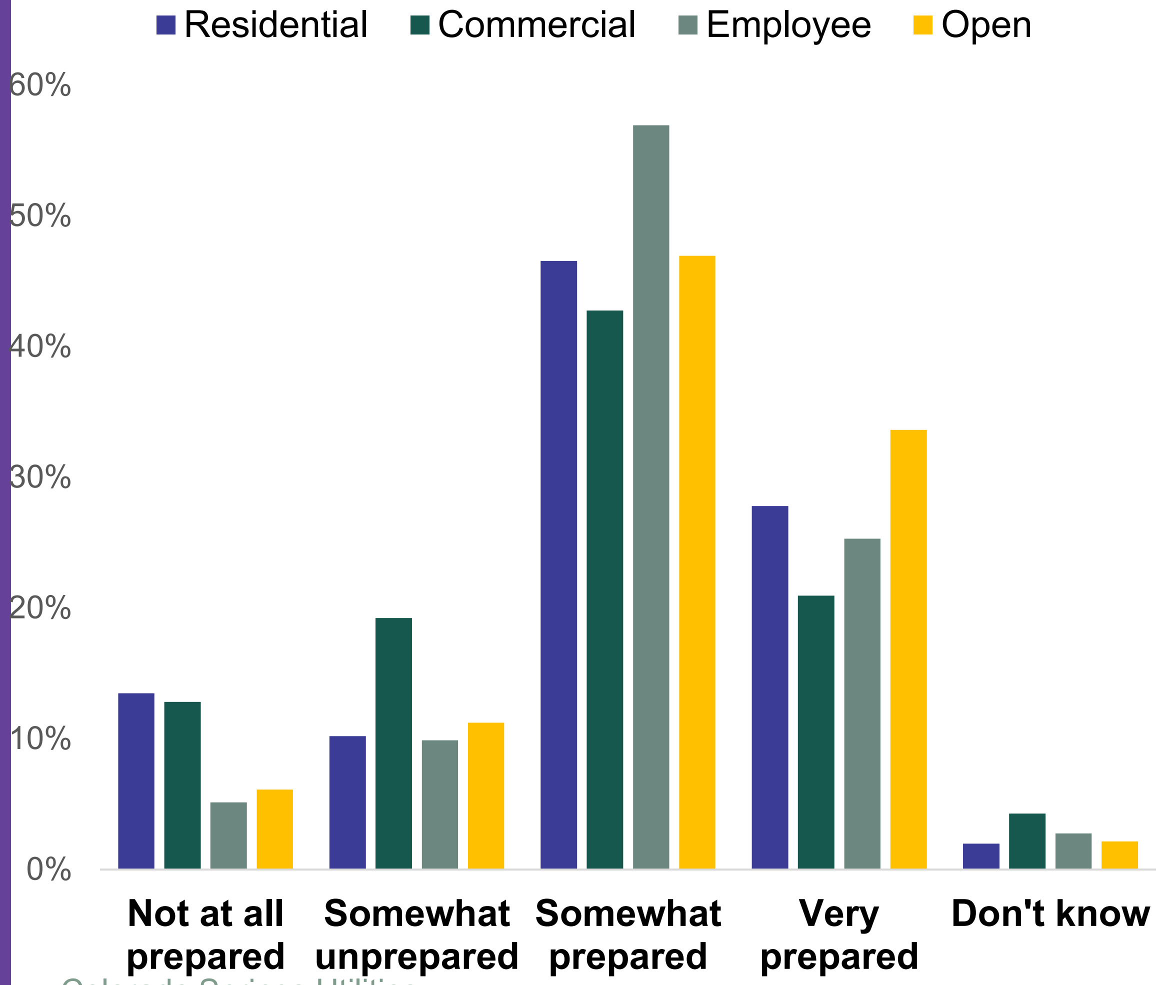
Phase 3 Community Survey Concept



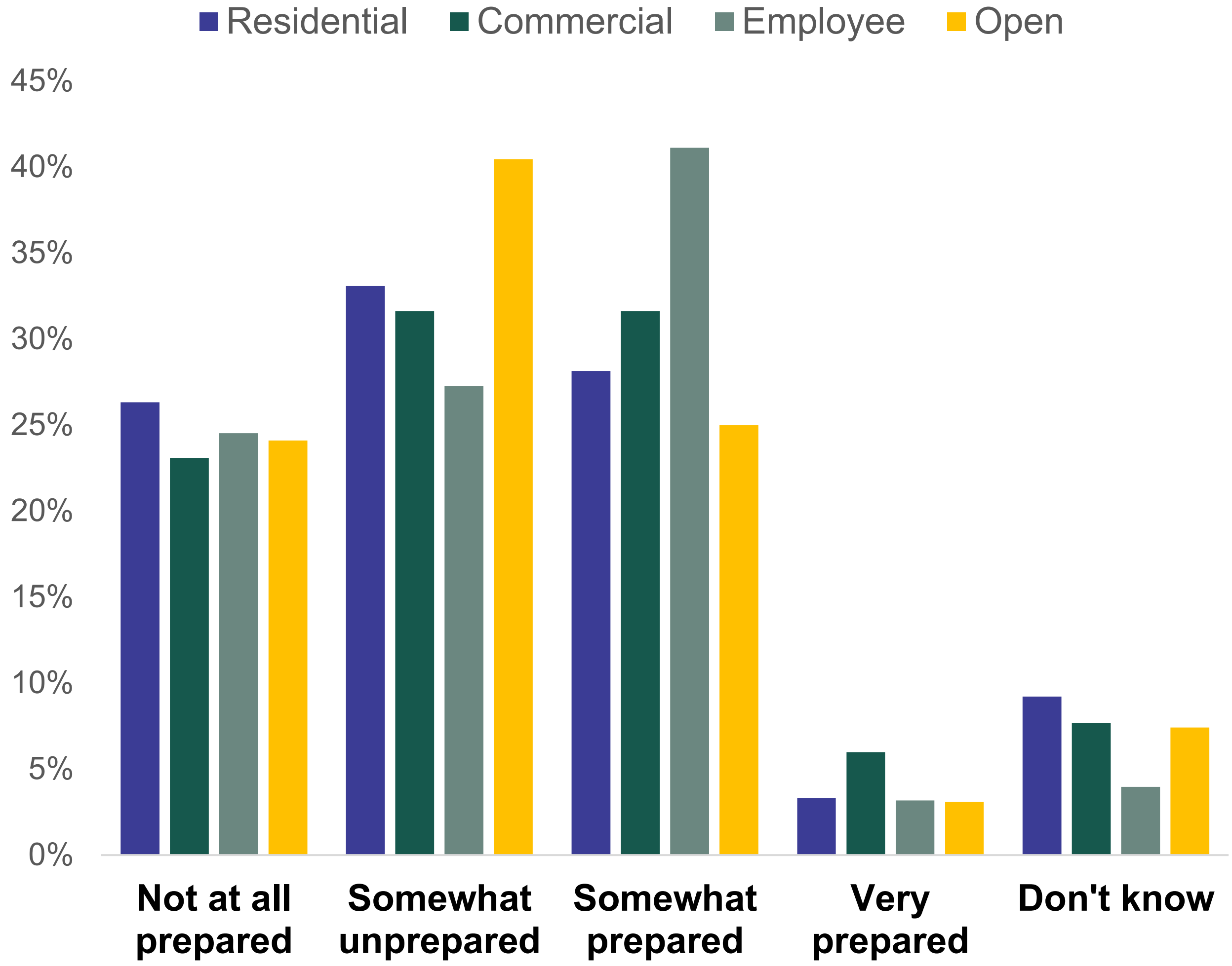
COVID-19 Results

IRP Survey Results

How prepared are you financially for the COVID-19 outbreak?



How prepared is our community for a COVID-19 outbreak?



Source: 2020 Integrated Resource Plan Phase 3 Survey – All Segments

Sampling Considerations

Quantitative

Random sampling methodology used

Residential results align with customer population demographics

Qualitative

Random sampling methodology not used

- Open survey results do not align with customer population demographics
- Generation X and Millennials under-represented
- Open respondents self-selected

EIRP Community Outreach

Survey Responses	Phase 3	Phase 2	Energy Vision
Residential	608	619	563
Commercial	234	136	143
Employee	253	350	183
Open	2,019	851	209
Total	**3,116**	**1,956**	**1,098**

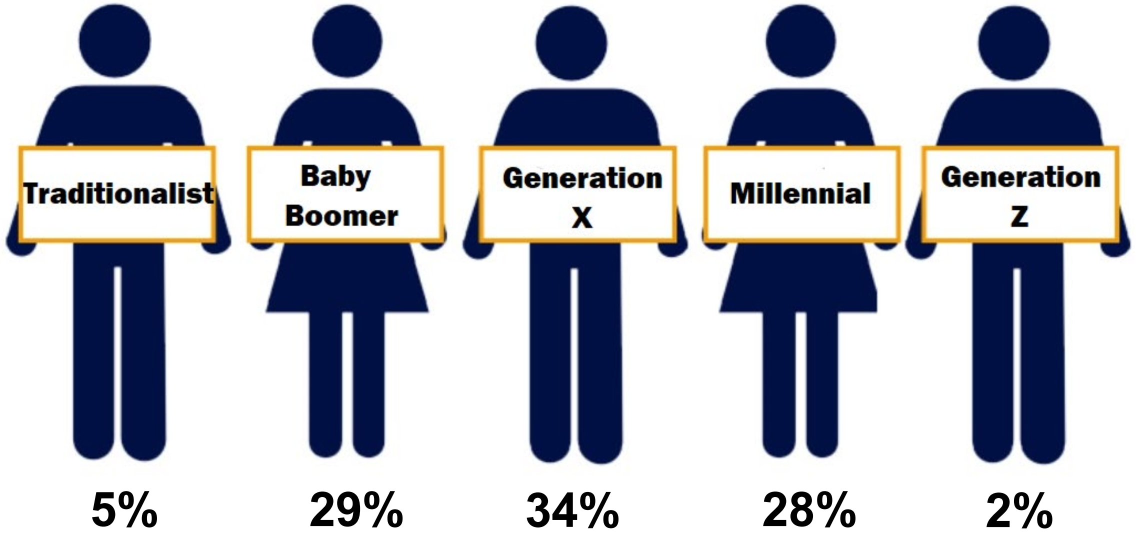
Phase 3 Community Outreach

Residential	Commercial	Employee	Open
n=608	n=234	n=253	n=2,019
Margin of Error ± 4.0%	Margin of Error ± 6.4%	Margin of Error ± 5.7%	Under-coverage Voluntary Response bias

Demographics

Residential Demographics

Quantitative Results

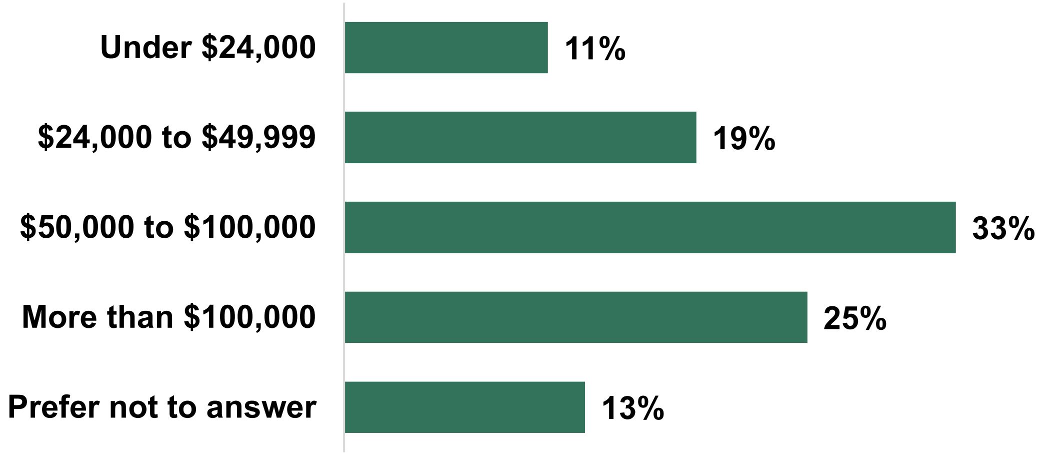


40% Renters

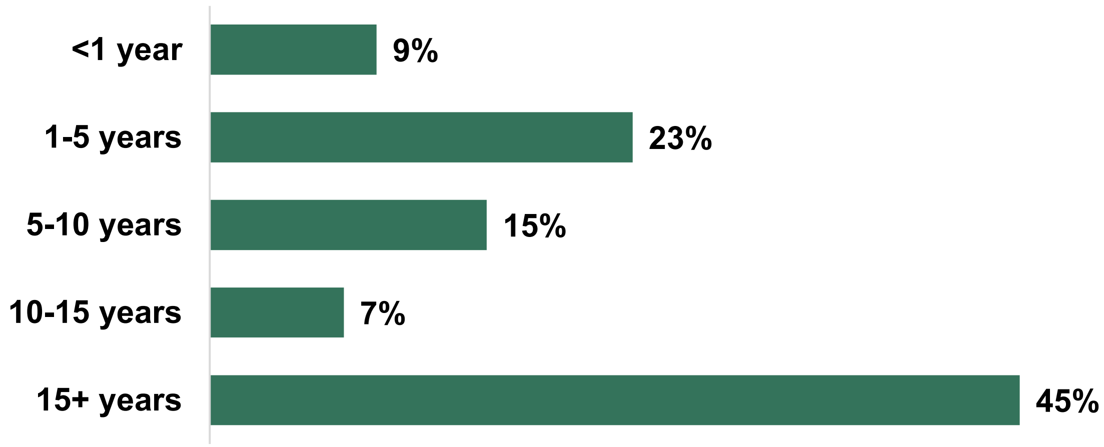
60% Homeowners

Total Respondents: 608

Income



Years In Service Territory



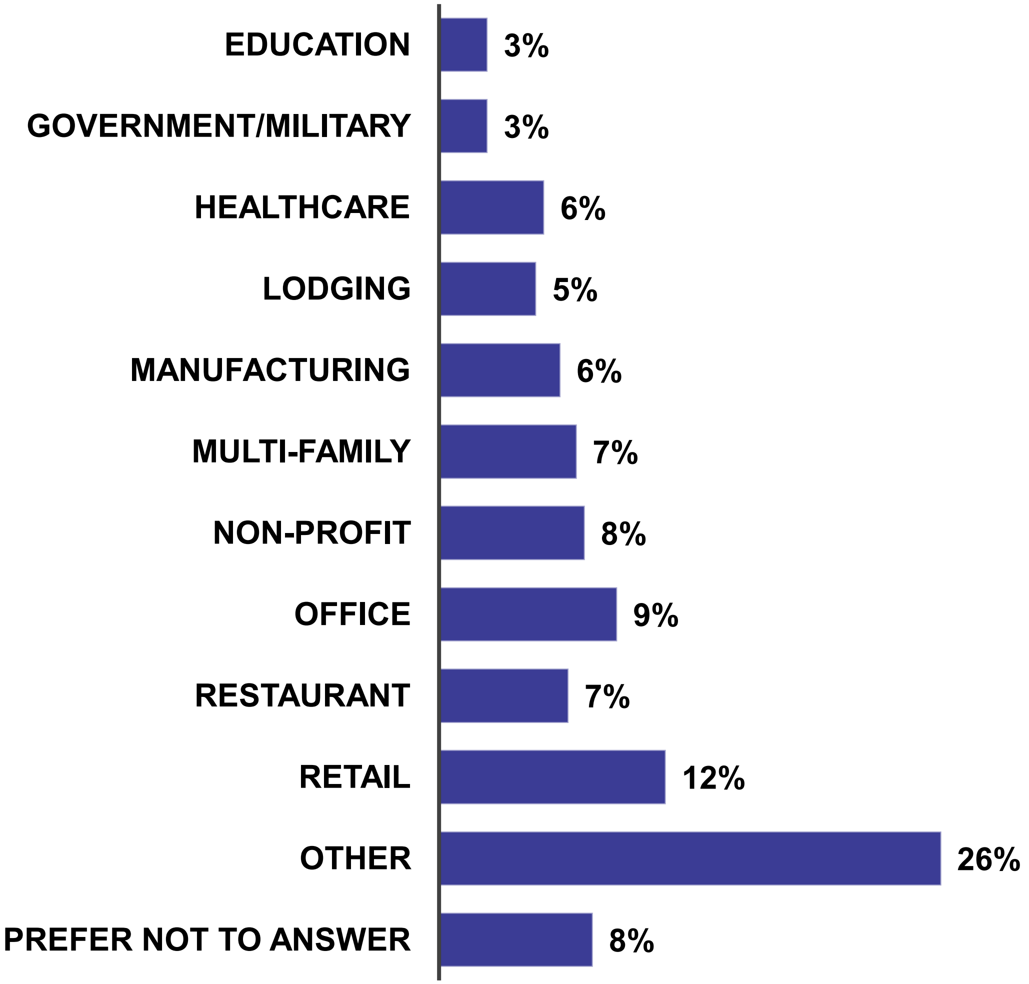
Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Commercial Demographics

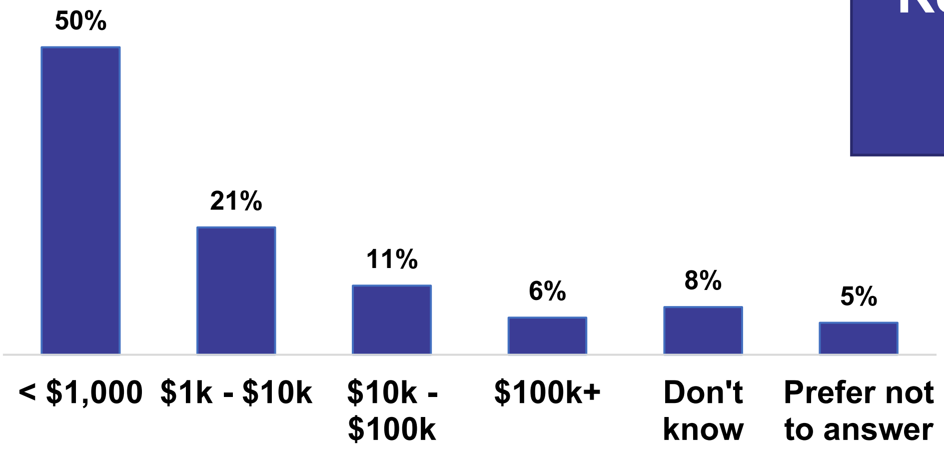
Qualitative Results

Total Respondents: 234

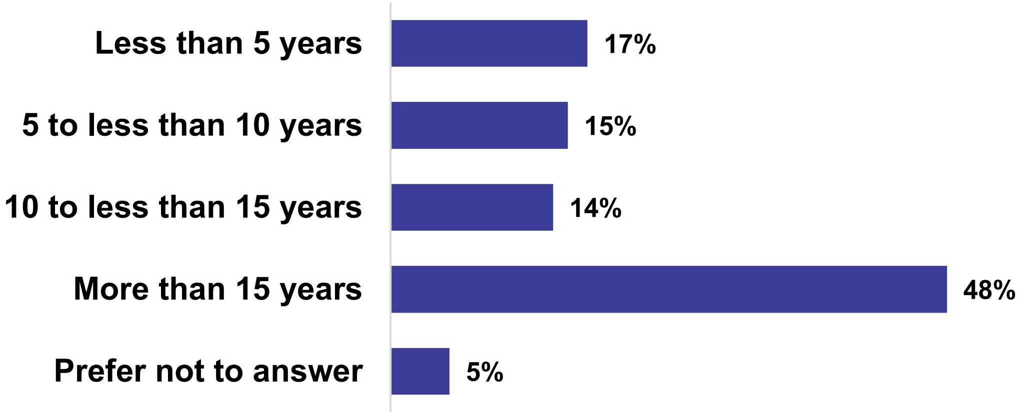
Business Type



Monthly Bill Amount



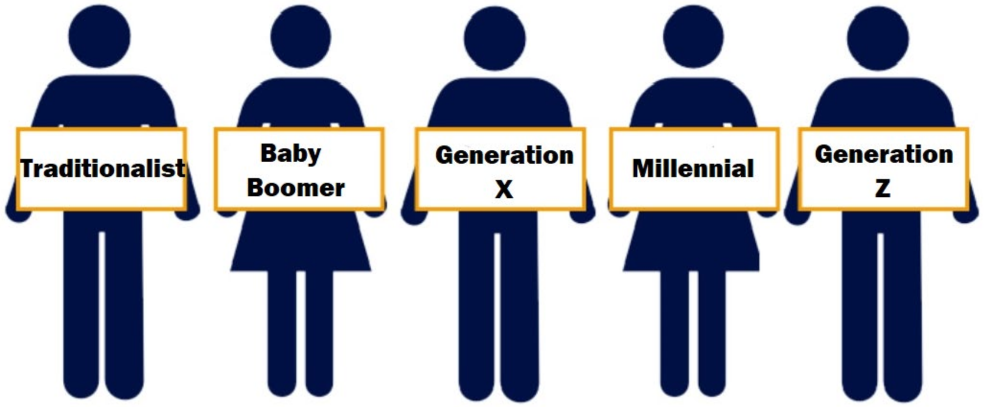
Years In Service Territory



Source: 2020 Integrated Resource Plan Phase 3 Survey – Commercial
n=234

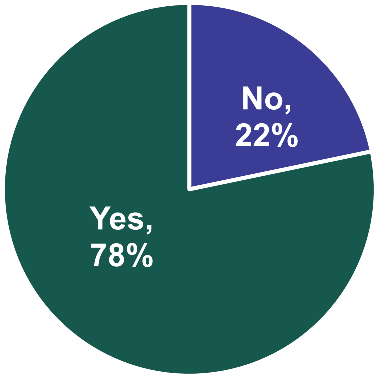
Employee Demographics

Qualitative Results



0% 28% 48% 22% 1%

Lives in Service Territory



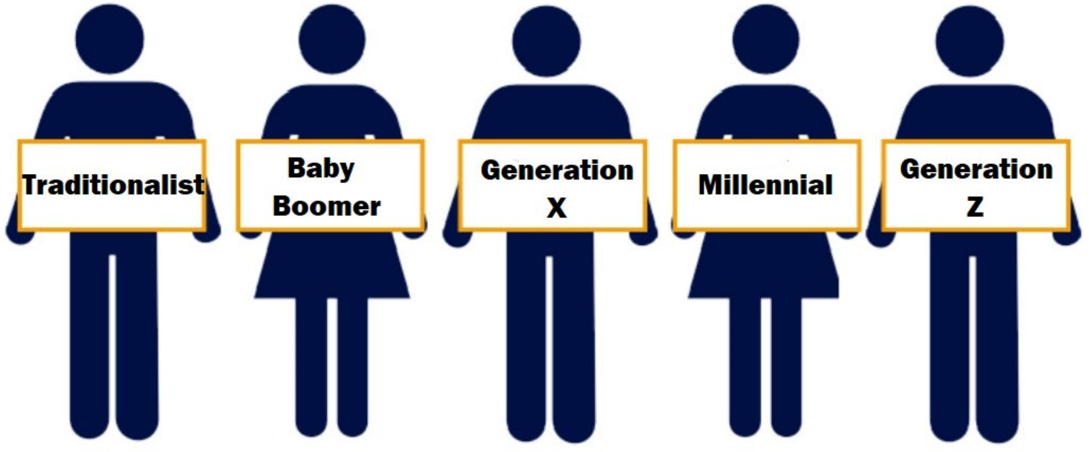
Total Respondents: 253

11% Renters **87% Homeowners**

Source: 2020 Integrated Resource Plan Phase 3 Survey – Employee
n=253

Open Demographics

Qualitative Results

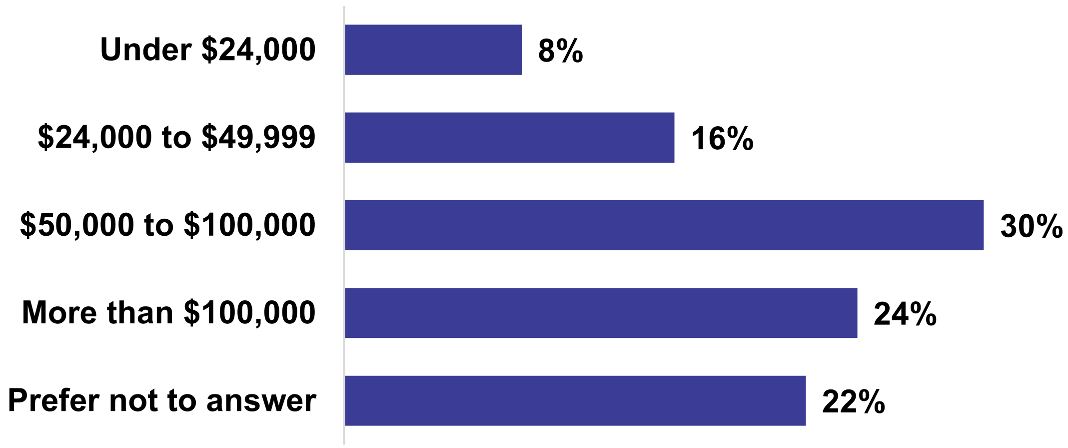


8% 36% 19% 19% 14%

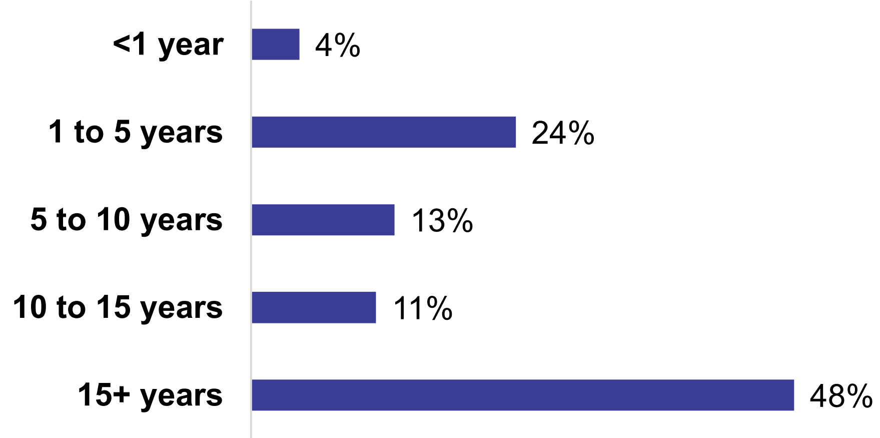
20% Renters
70% Homeowners

Total Respondents: 2,019

Income



Years in Service Territory



Sources: 2020 Integrated Resource Plan Phase 3 Survey – Open, Instagram, Smart Home, Snapchat
n=2,019

Quantitative Results

Key Quantitative Findings

Residential

Preferred Pathway: New Renewable Resources

Environmental Goals and New Energy Resources chosen in three pathways as the influence

Chosen pathway bill impact: 26% not willing to accept an increase; 22% willing to accept $15 or more

Emissions Approach: Moderate

DSM responsibility: Individuals at 40%

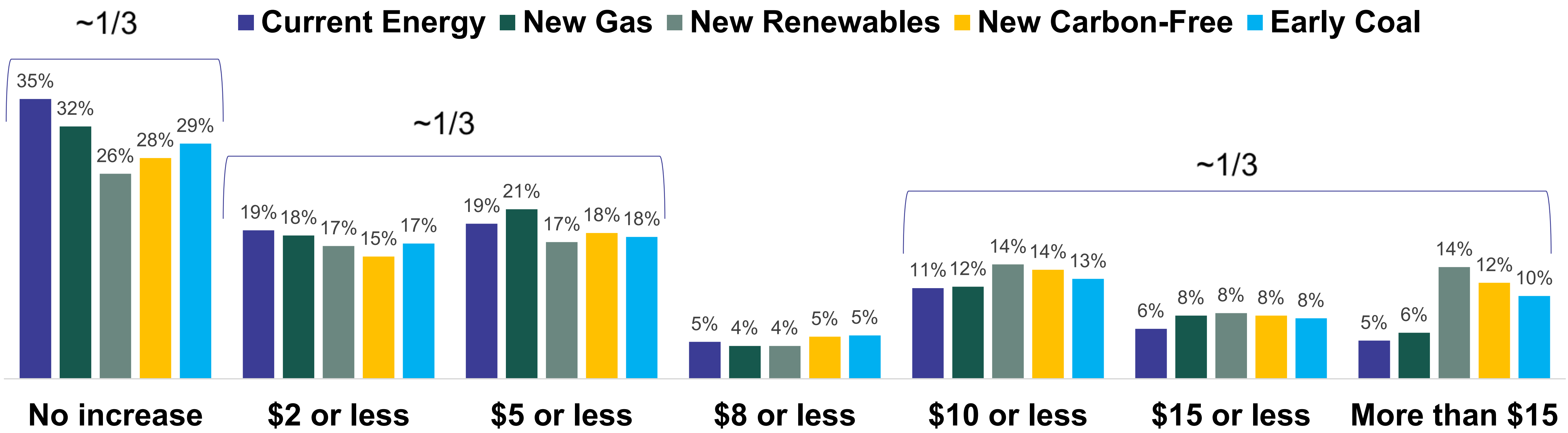
Current Energy Resources Reference Case	New Gas Resources Pathway B	New Renewable Resources Pathway C	New Carbon Free Resources Pathway D	Early Coal Retirement Pathway E
50% carbon reduction by 2030; 90% carbon reduction by 2050	80% carbon reduction by 2030; 90% carbon reduction by 2050	80% carbon reduction by 2030; 100% renewable by 2050	80% carbon reduction by 2030; 100% carbon reduction by 2050	80% carbon reduction by 2023; 100% carbon reduction by 2030
Regulatory Requirements Level: Meets	Regulatory Requirements Level: Exceeds	Regulatory Requirements Level: Exceeds	Regulatory Requirements Level: Exceed	Regulatory Requirements Level: Exceeds
Natural gas, renewables and storage, and customer efficiency efforts	Natural gas and customer efficiency efforts	Renewables and storage and customer efficiency efforts	Carbon-free and customer efficiency efforts	Natural gas, renewables and storage, and customer efficiency efforts
All units at Drake retired by 2035	All units at Drake retired by 2026 and all coal-fired units at Nixon retired by 2030	All units at Drake retired by 2026 and all coal-fired units at Nixon retired by 2030. All fossil fuels retired by 2050.	All units at Drake retired by 2026 and all coal-fired units at Nixon retired by 2030. All fossil fuels retired by 2050.	All units at Drake retired by 2023 and coal-fired units at Nixon retired by 2026

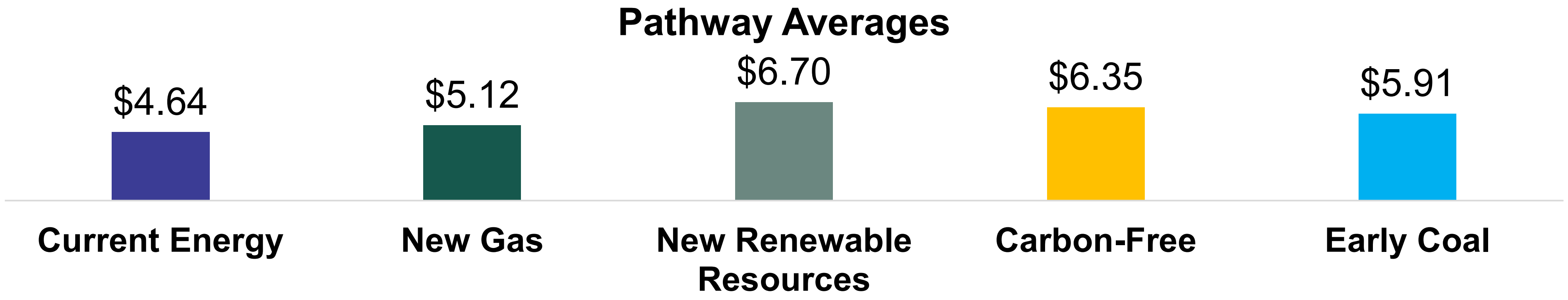
Survey Definitions

- **Renewables**: Solar, battery storage, wind, geothermal, hydropower, biomass, biogas, landfill gas, and other renewable resources as defined by Colorado statute.
- **Carbon-free:** Resources which have no greenhouse gas emission during operation, like renewables, nuclear, and those which include carbon capture.
- **Customer efficiency/renewable energy efforts:** Energy efficiency, peak demand reduction and distributed resources such as rooftop solar and battery storage owned by the customer.
- **Drake**: The Martin Drake Power Plant located in downtown Colorado Springs. Drake is a coal-fired plant.
- **Fossil fuels:** For the purpose of this survey, coal and natural gas.
- **Nixon:** The Ray D. Nixon Power Plant located south of Colorado Springs. Nixon has both coal-fired and natural gas-fired generation.

Acceptable Bill Increase

Residential Survey Results

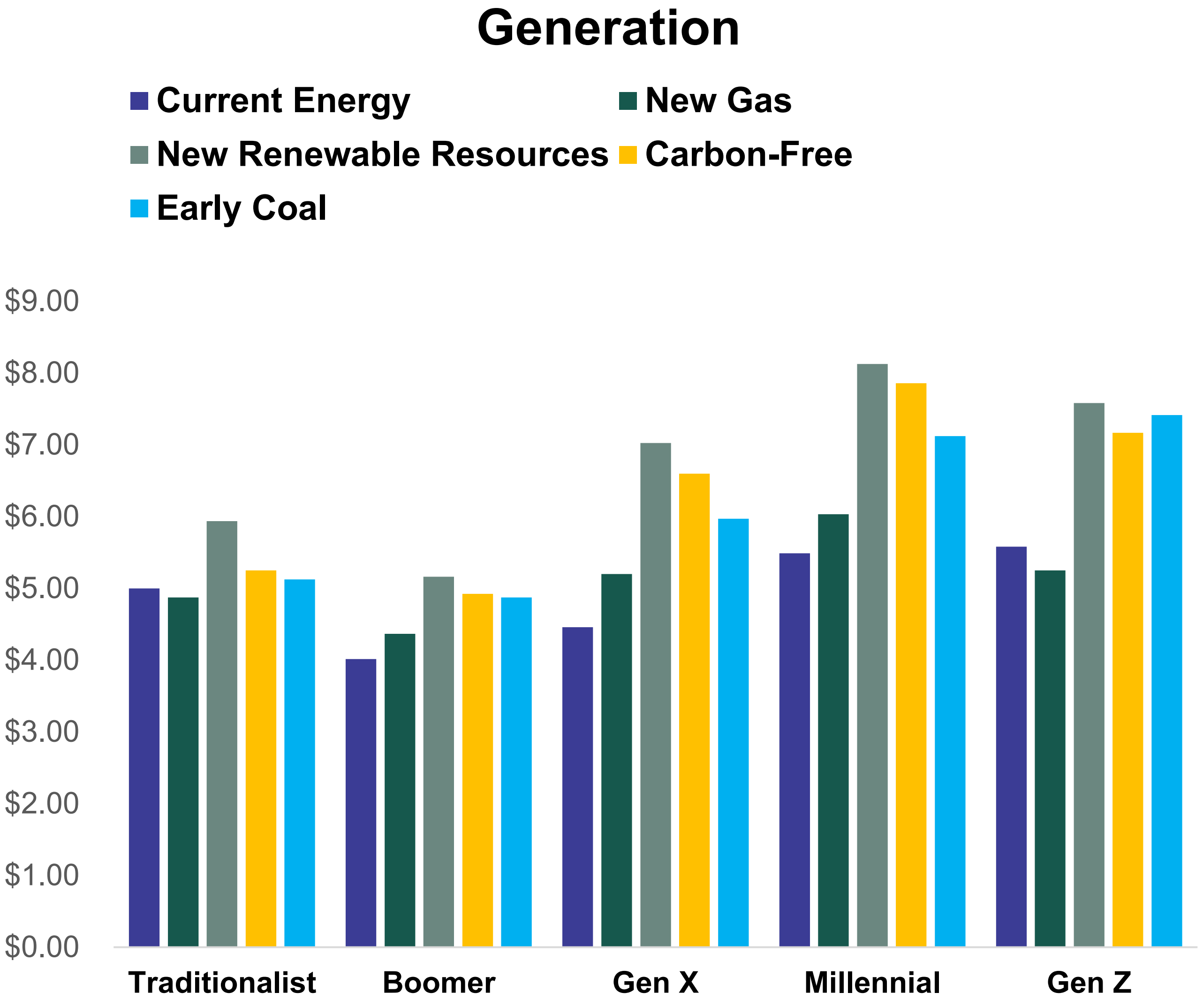


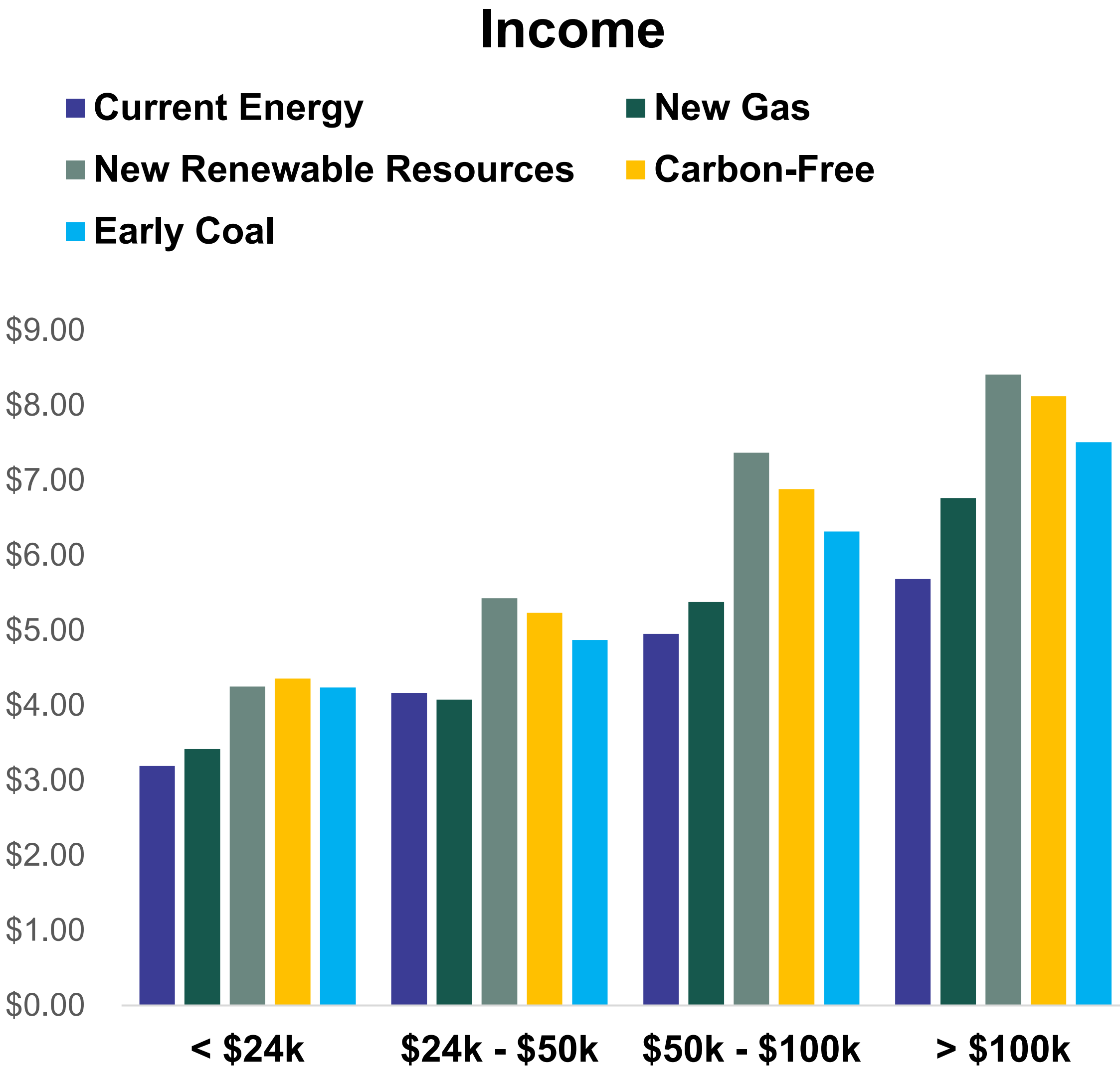


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Average Acceptable Bill Increase

Residential Survey Results

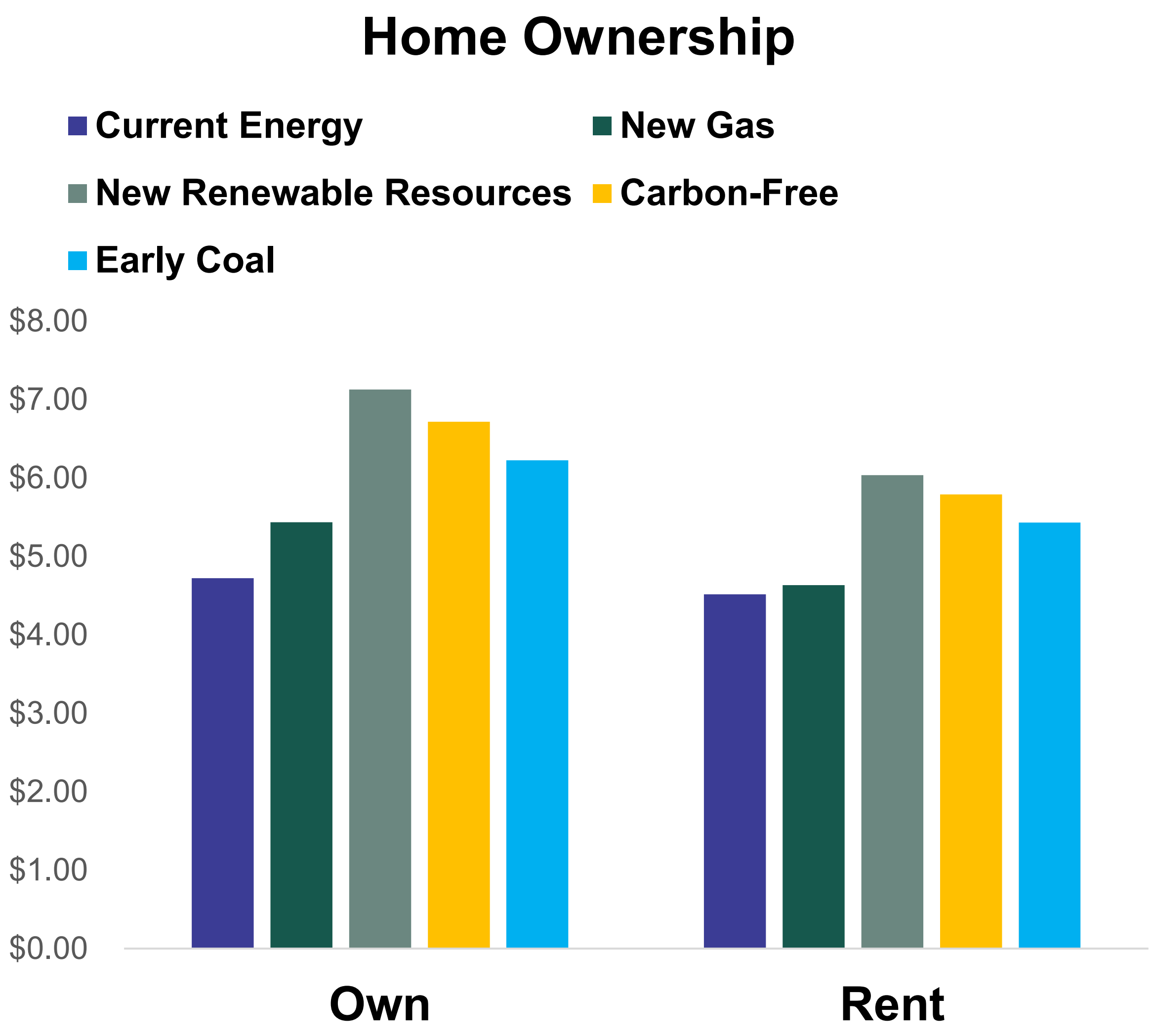




Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Average Acceptable Bill Increase

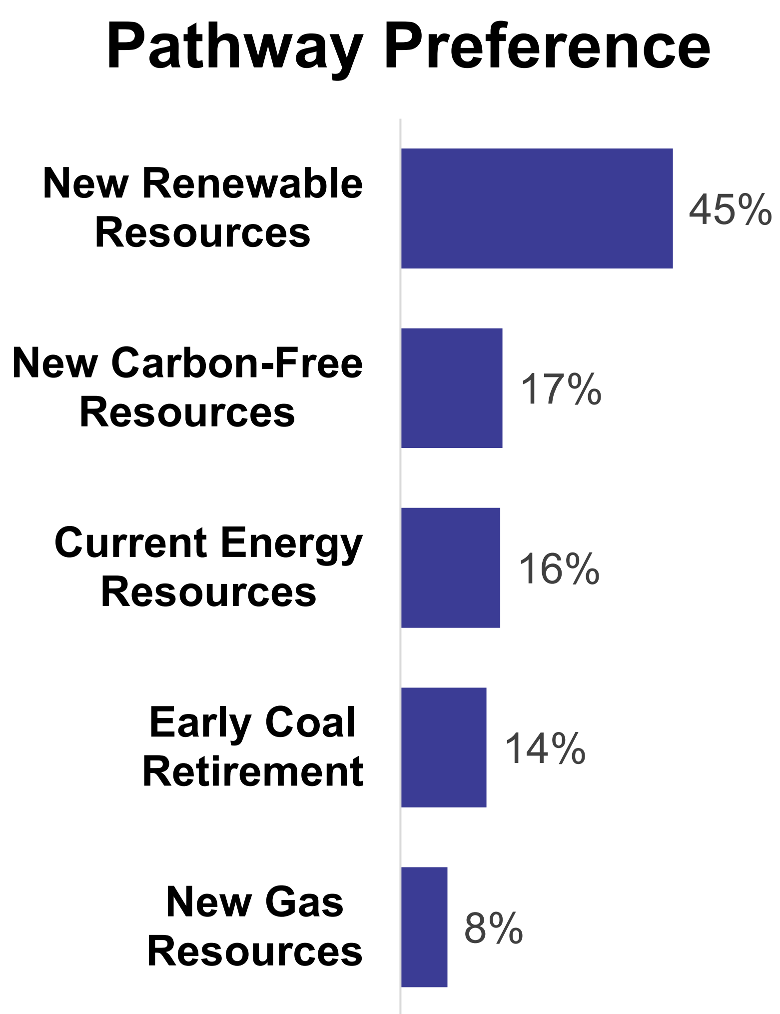
Residential Survey Results

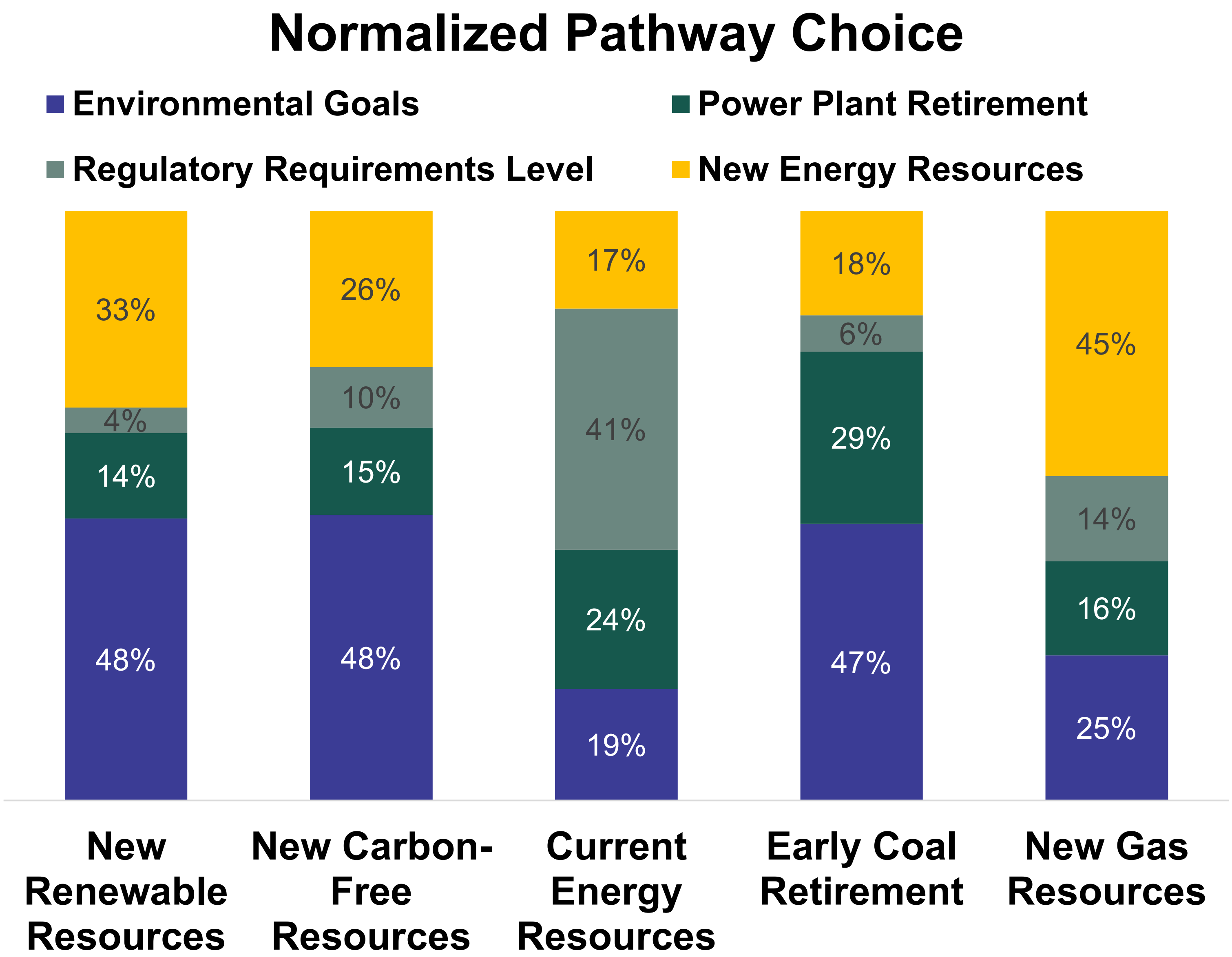


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Pathway Results

Residential Survey Results

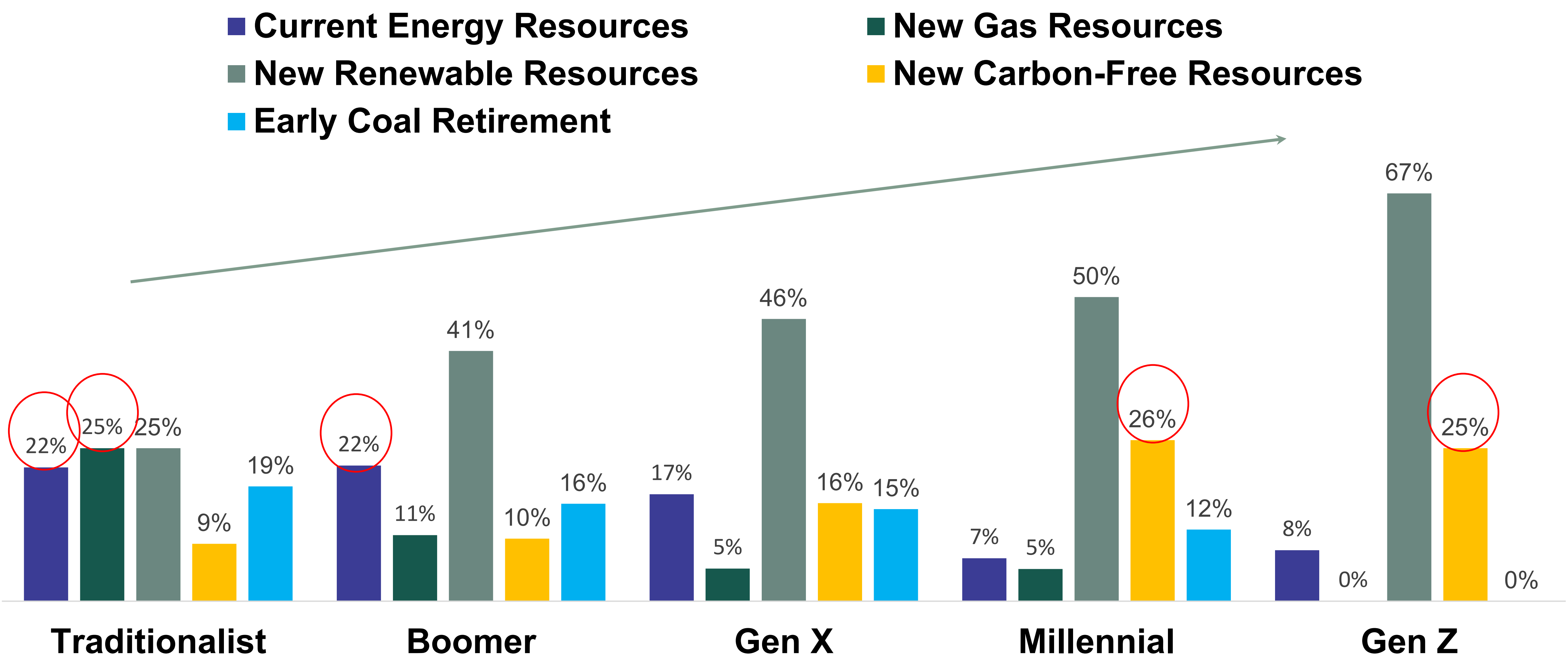




Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Pathway Results By Generation

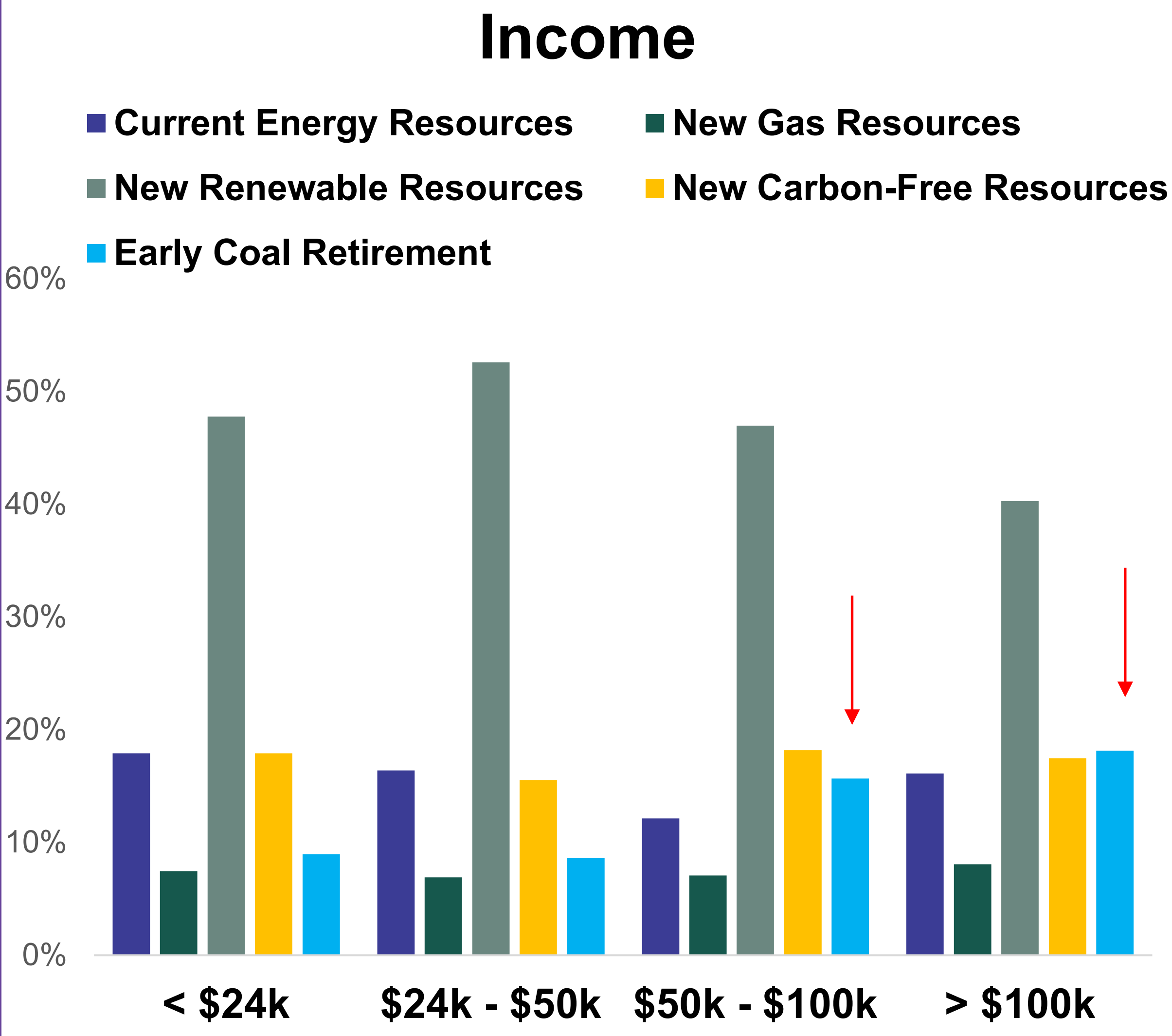
Residential Survey Results

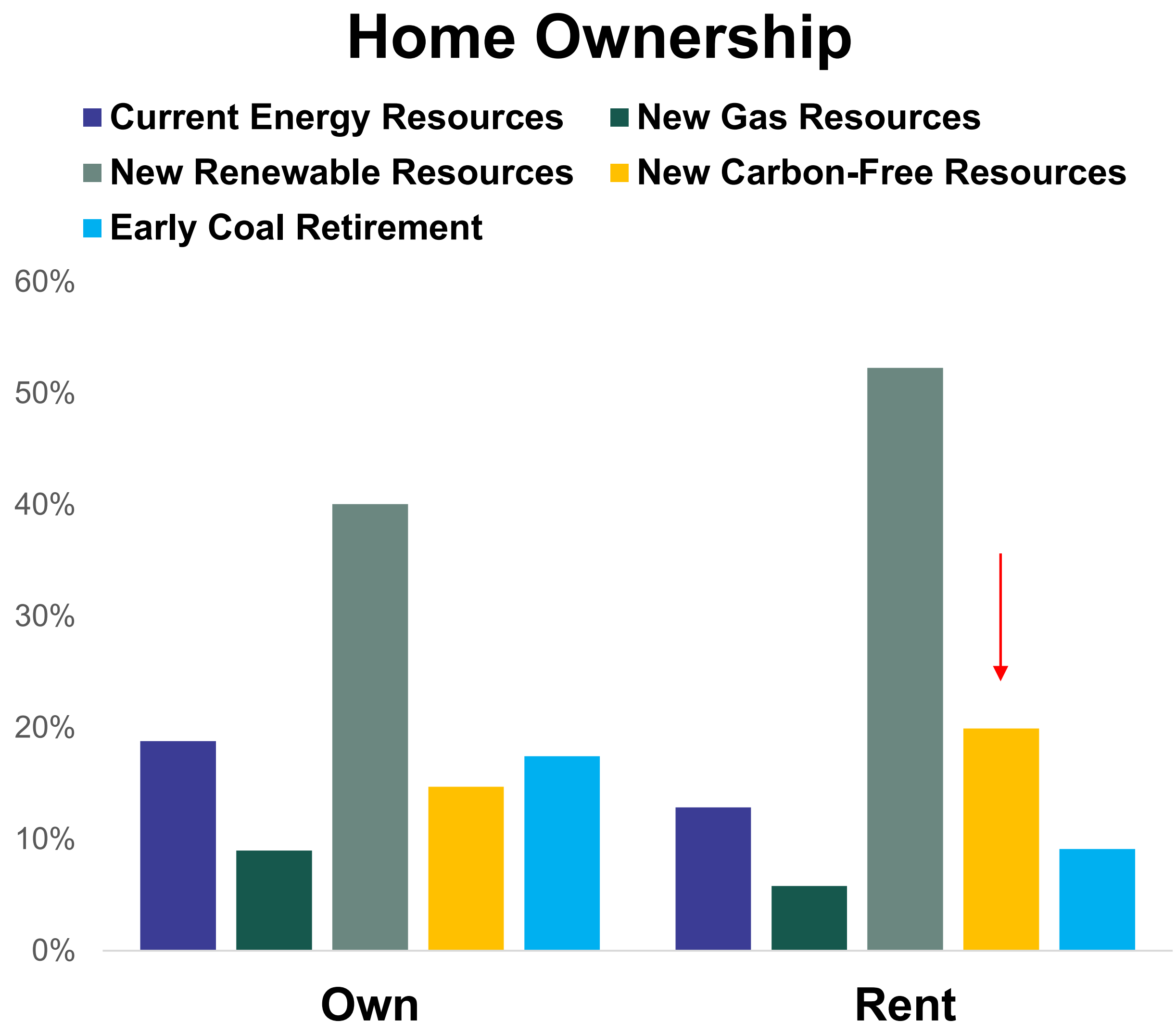


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Pathway Results

Residential Survey Results

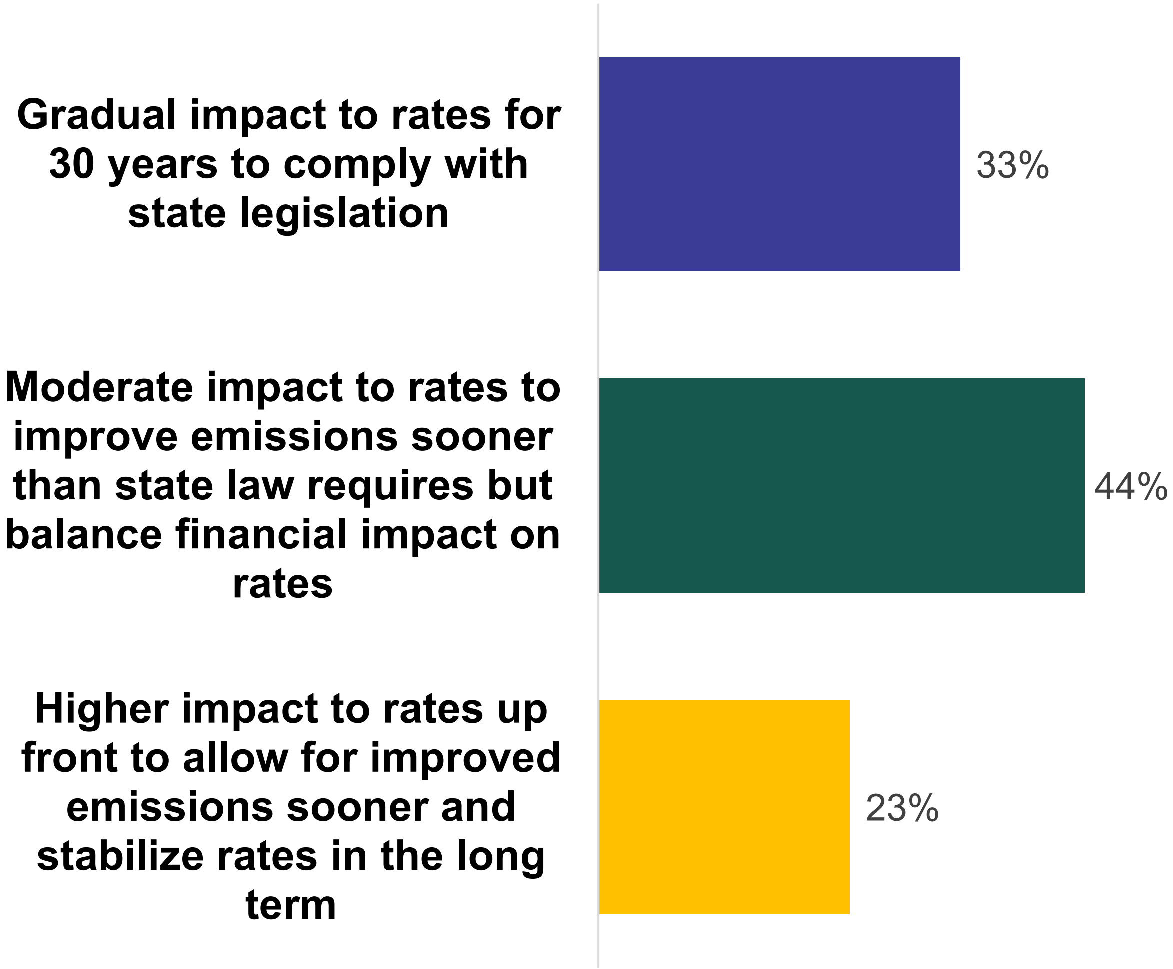




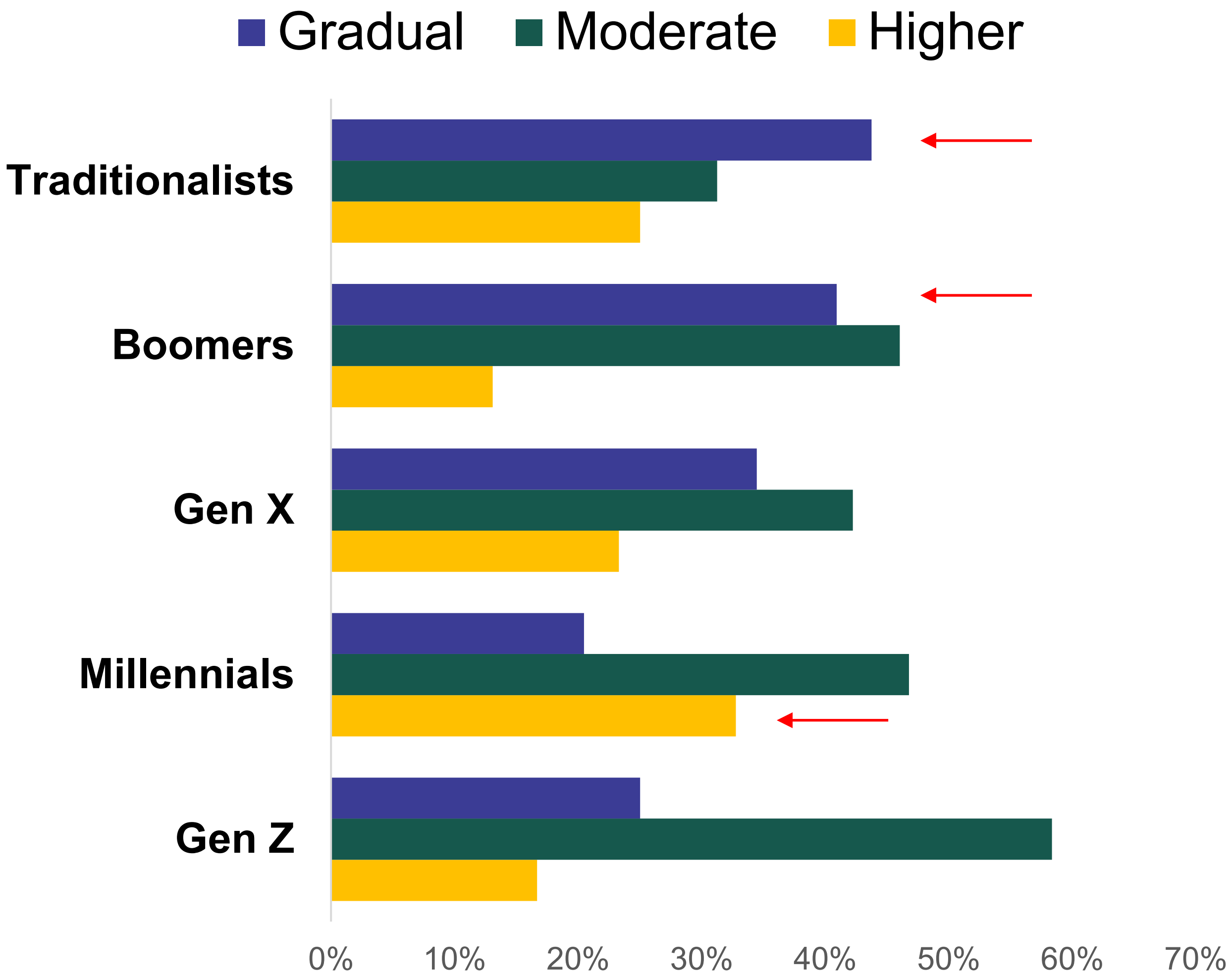
Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Carbon Emissions
Residential Survey Results

Carbon Emissions Approach

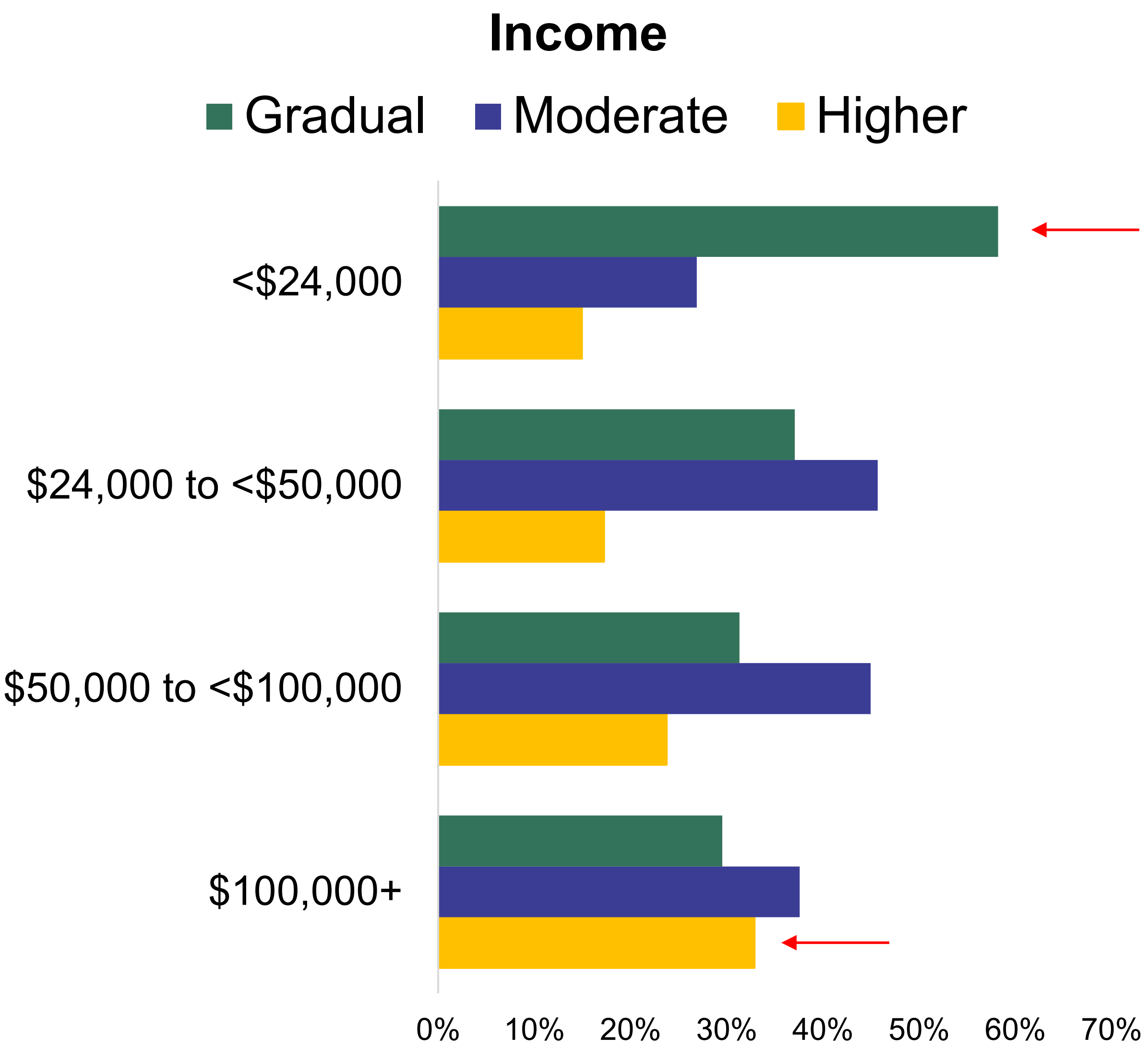


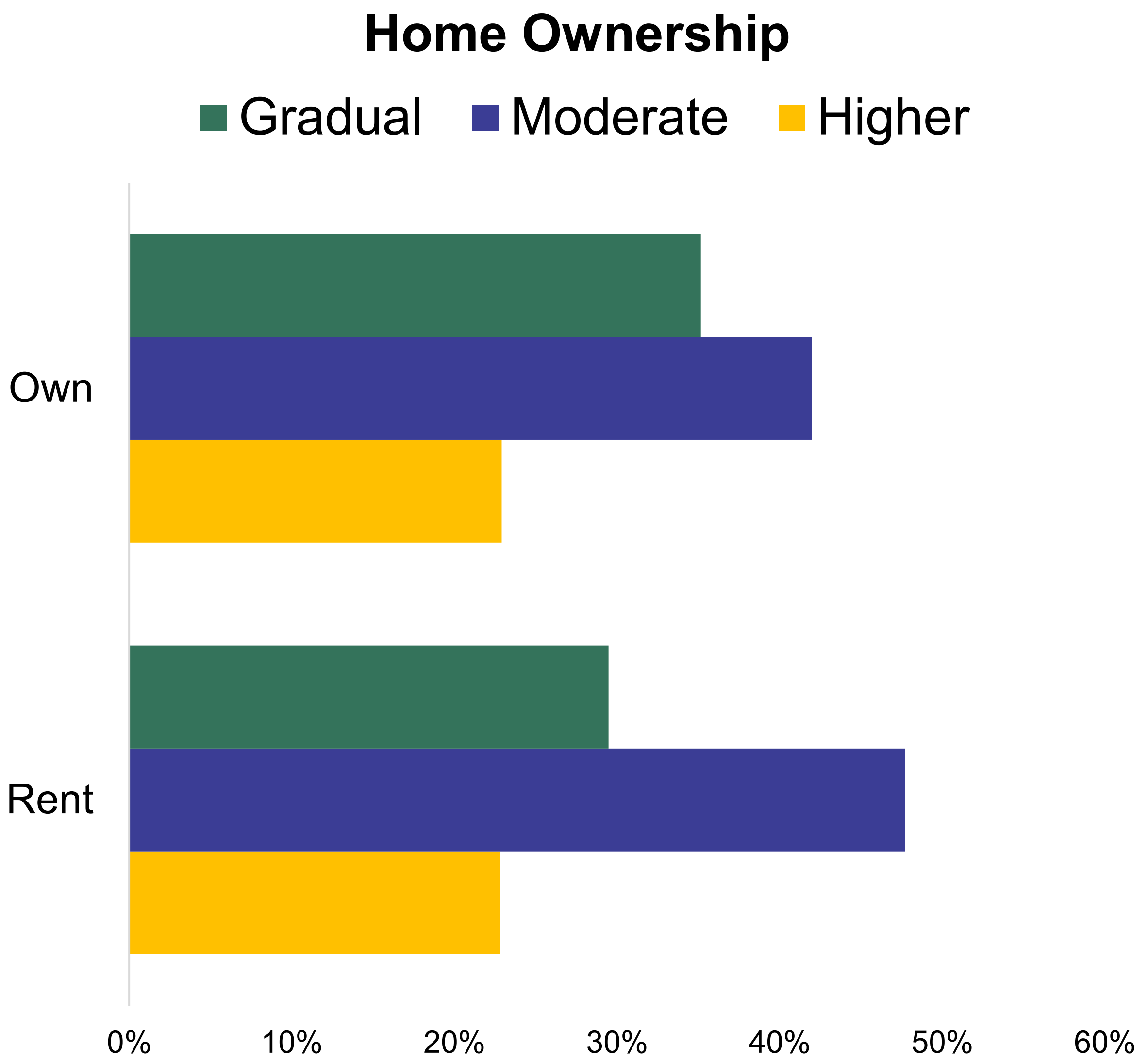
Generation



Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Carbon Emissions
Residential Survey Results

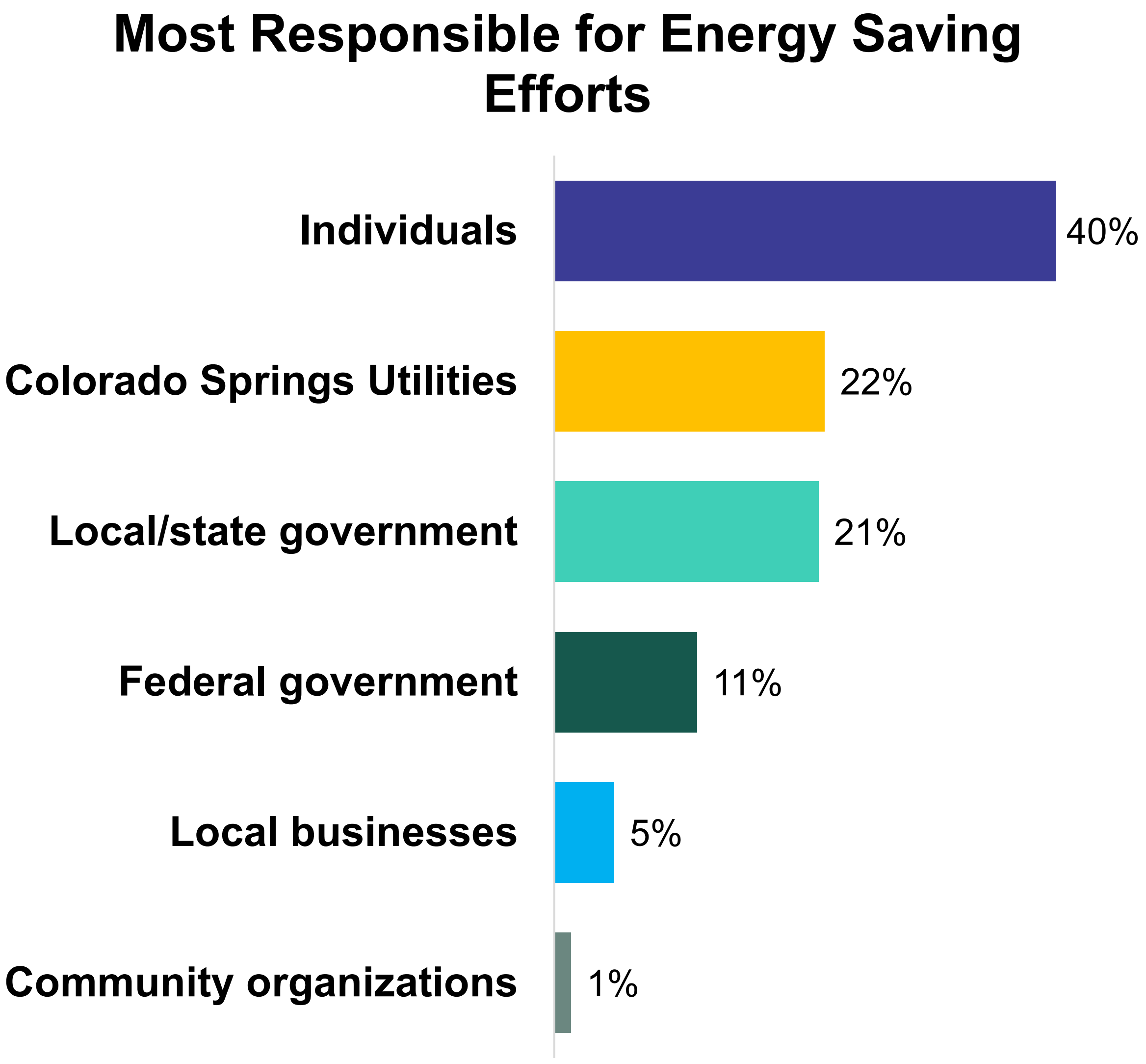


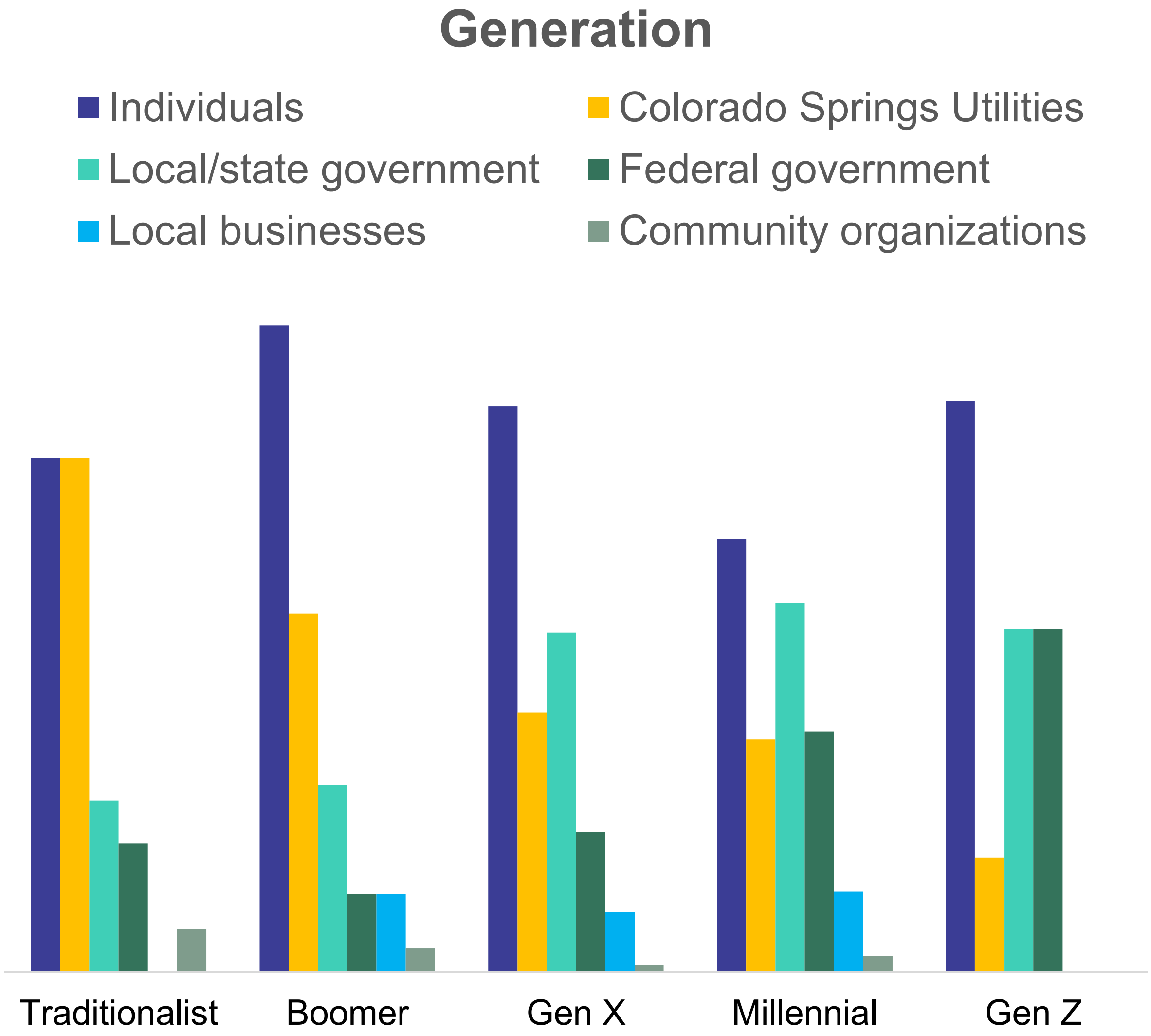


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Energy Saving Effort Responsibility

Residential Survey Results

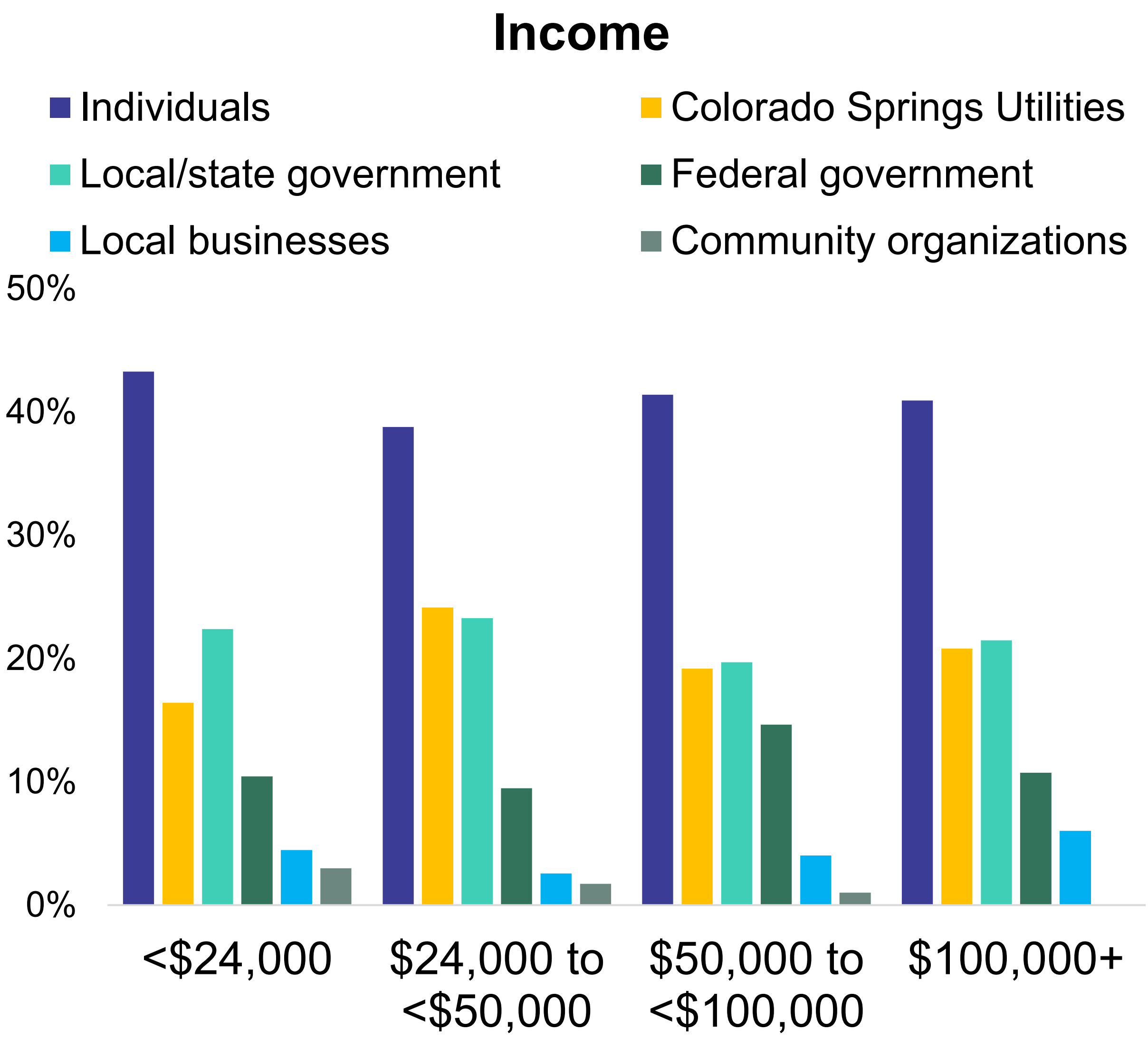


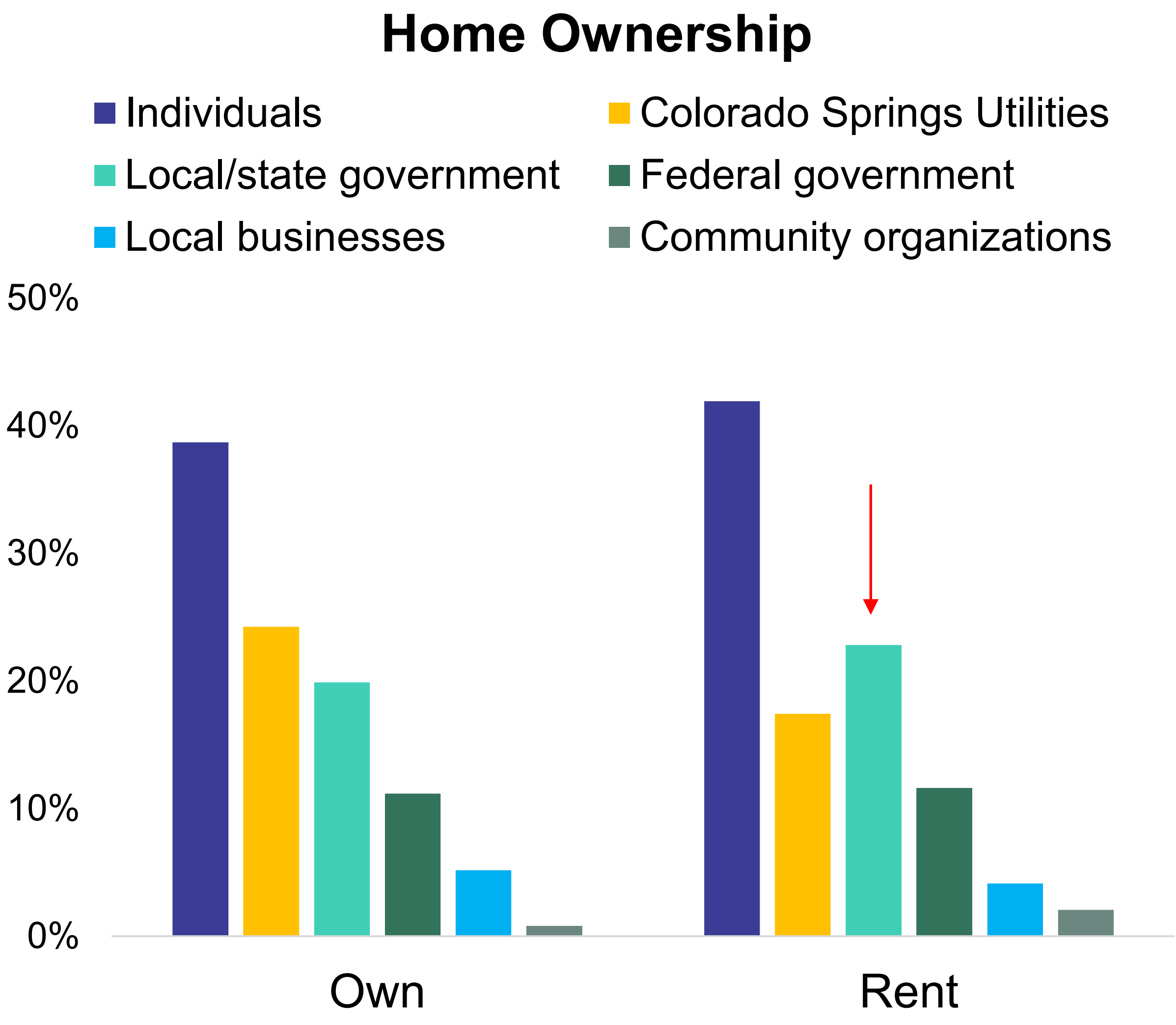


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Energy Saving Effort Responsibility

Residential Survey Results

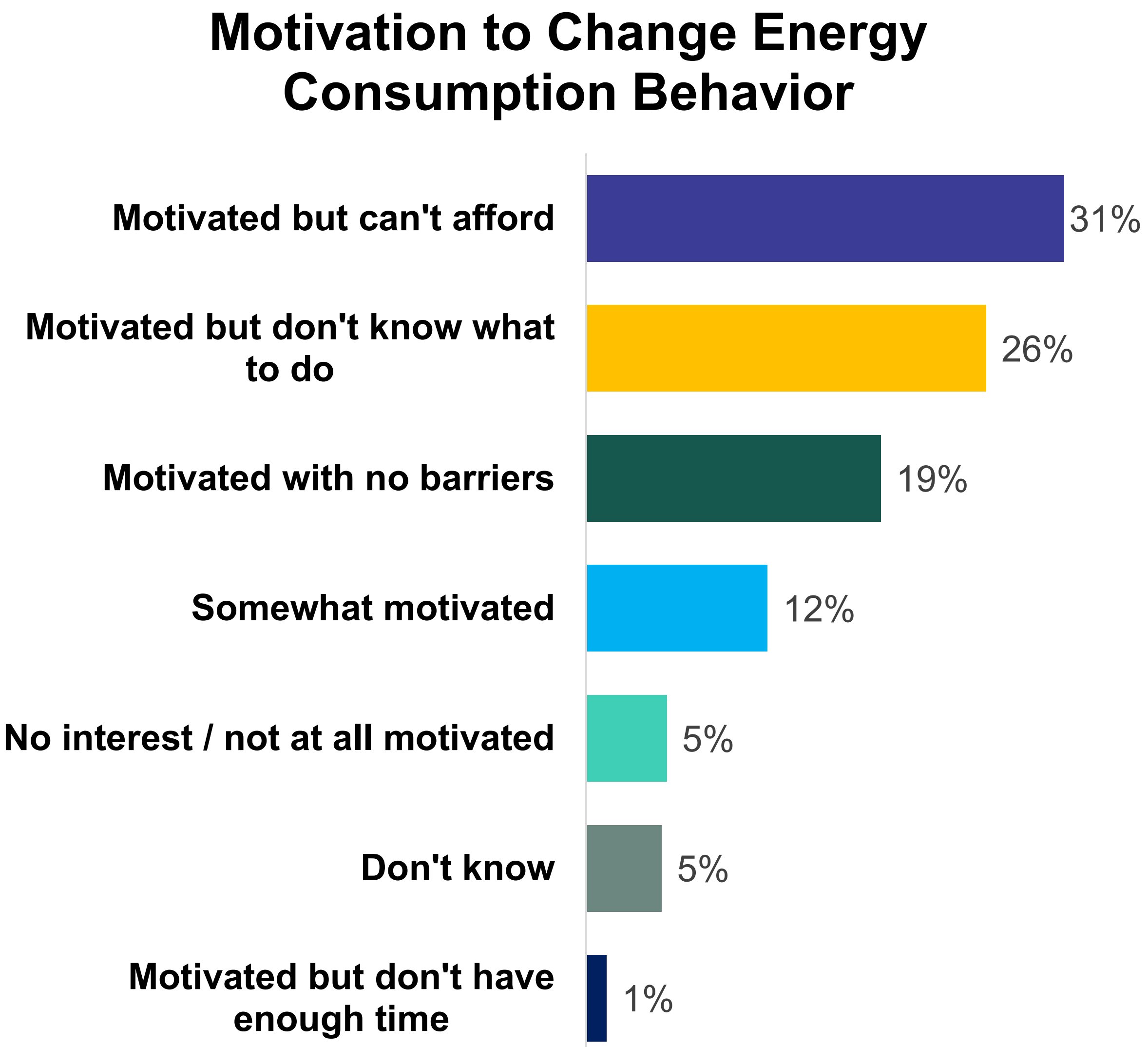


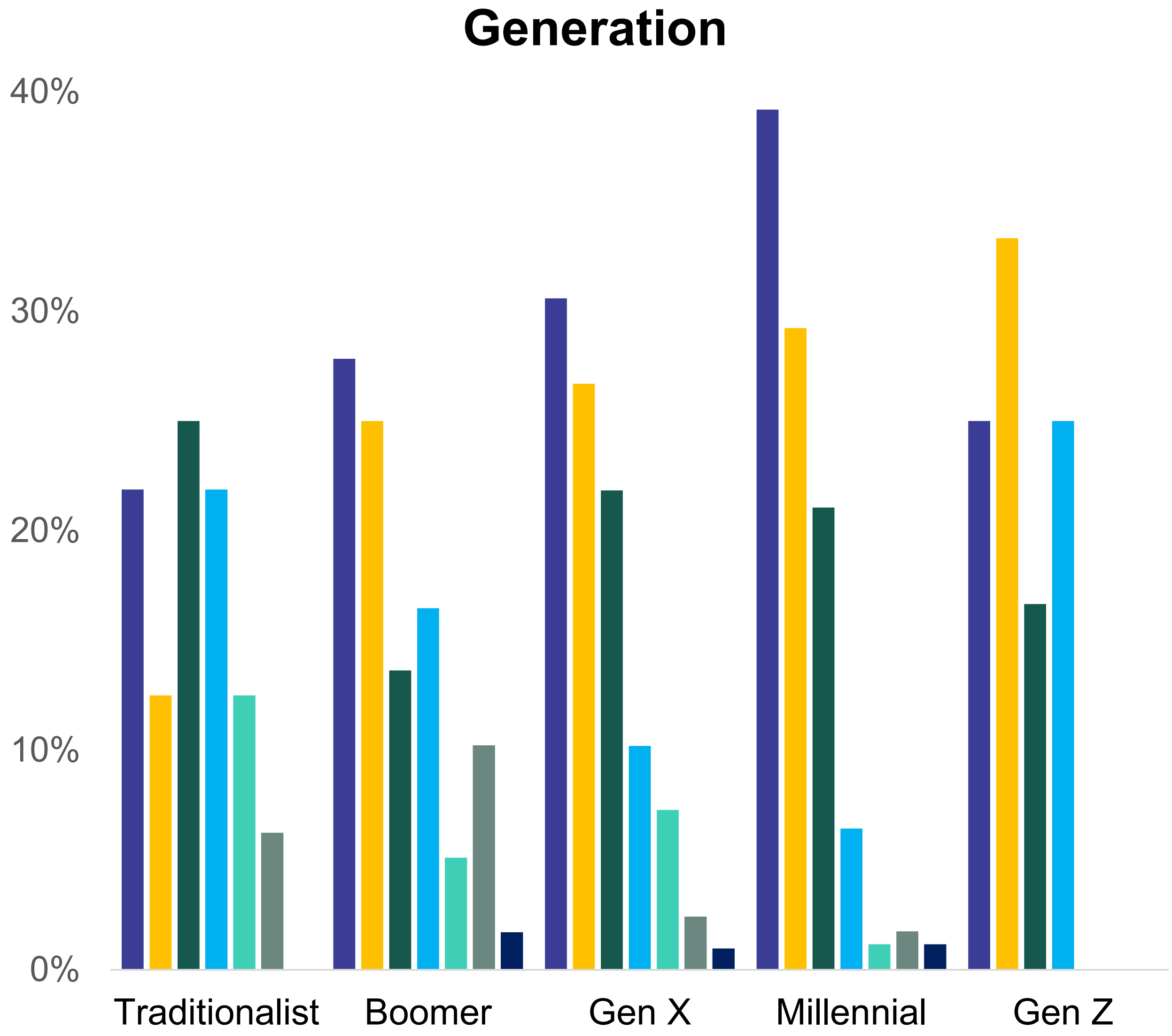


Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Energy Saving Effort Motivation

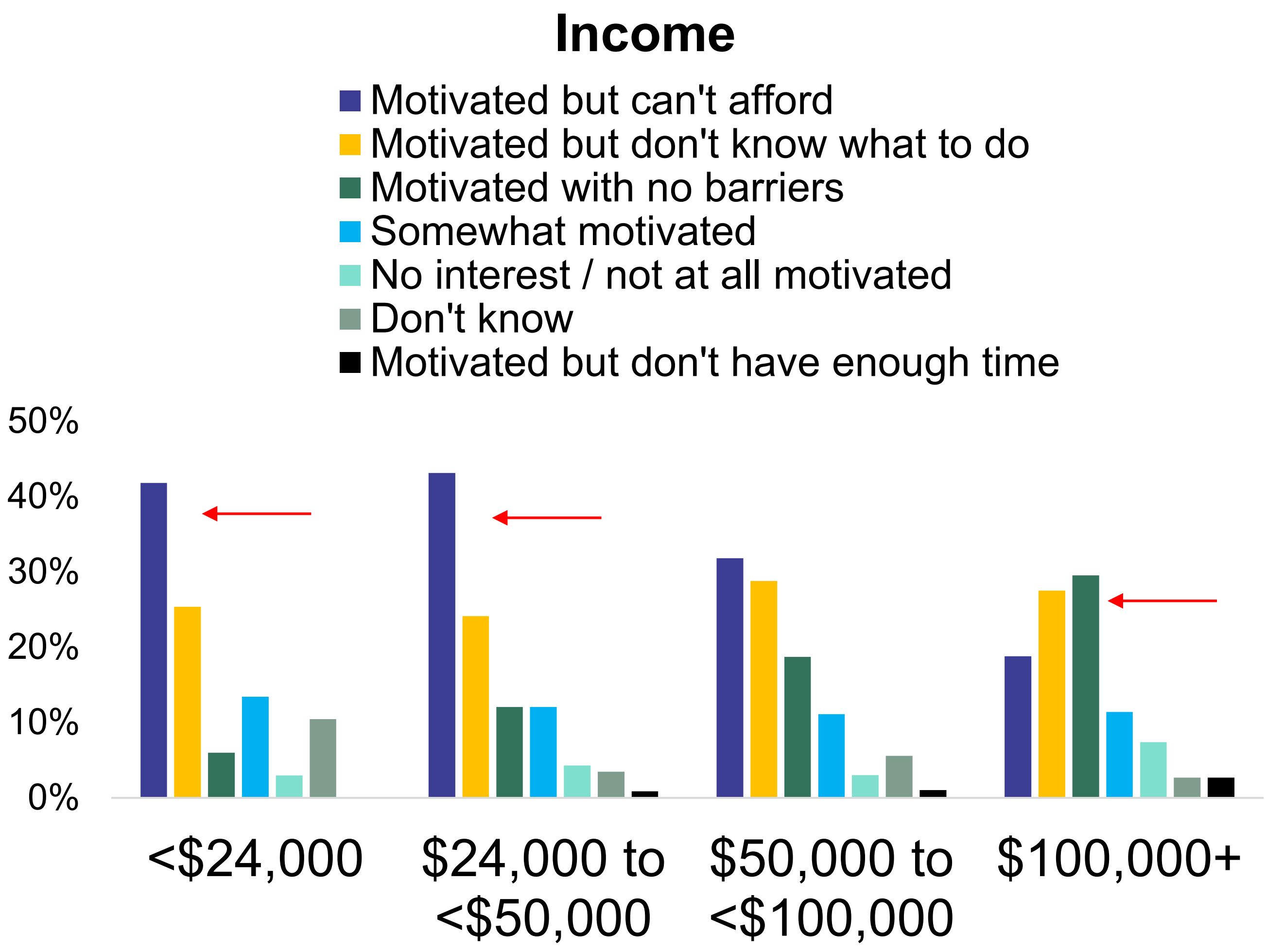
Residential Survey Results

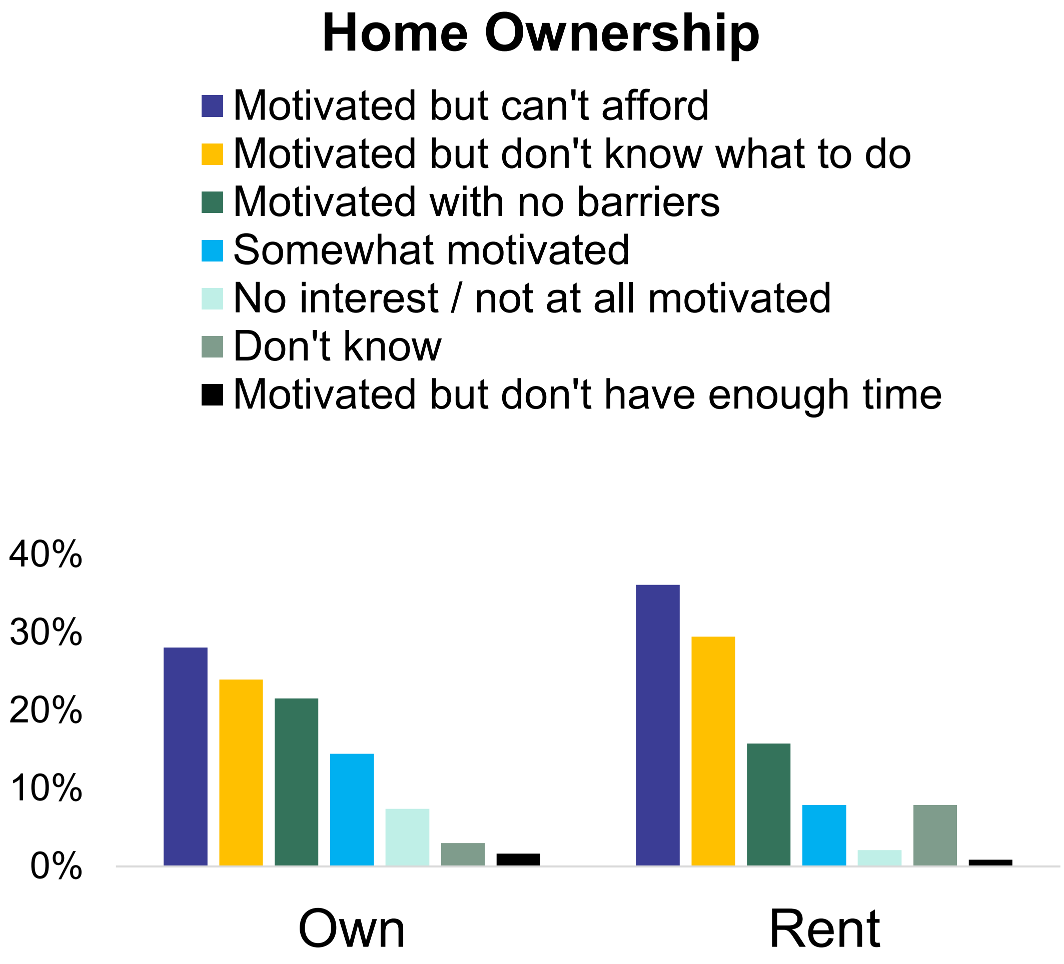




Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Energy Saving Effort Motivation



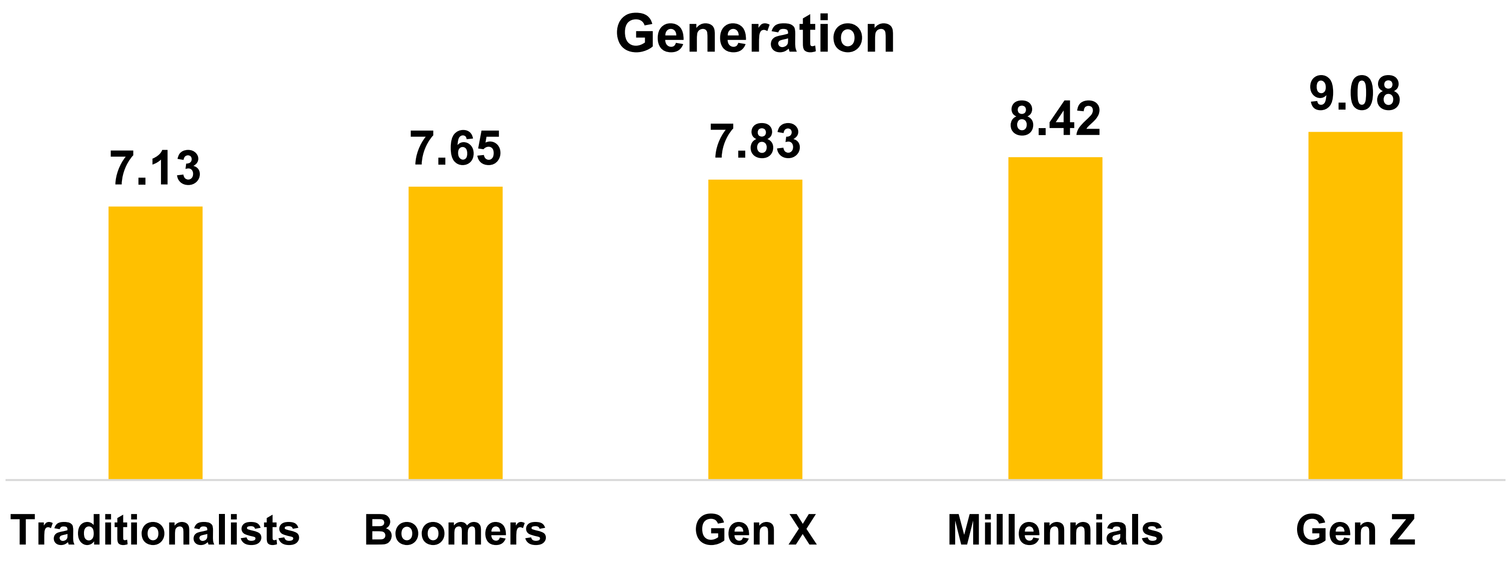


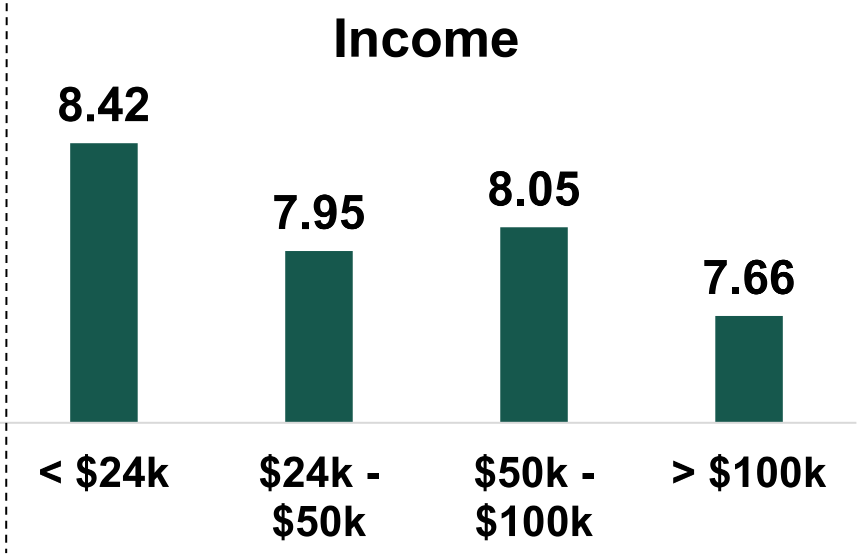
Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

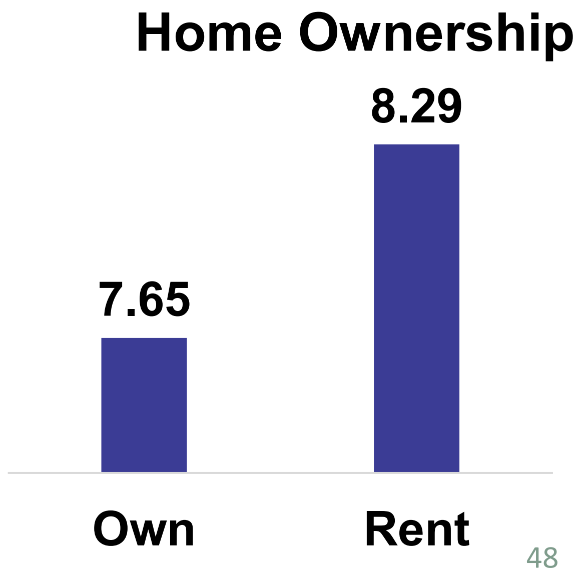
Energy Planning Results

On a scale from 1 to 10, how important is customer efficiency/renewable energy efforts in energy planning?

Average:
7.90







Source: 2020 Integrated Resource Plan Phase 3 Survey – Residential
n=608

Qualitative Results

Key Qualitative Findings

Commercial

- Preferred Pathway: New Renewable Resources
- Chosen Pathway Bill Impact: 39% not willing to accept an increase; 13% 10% or more
- Emissions Approach: Moderate
- DSM Responsibility: Individuals at 37%

Employee

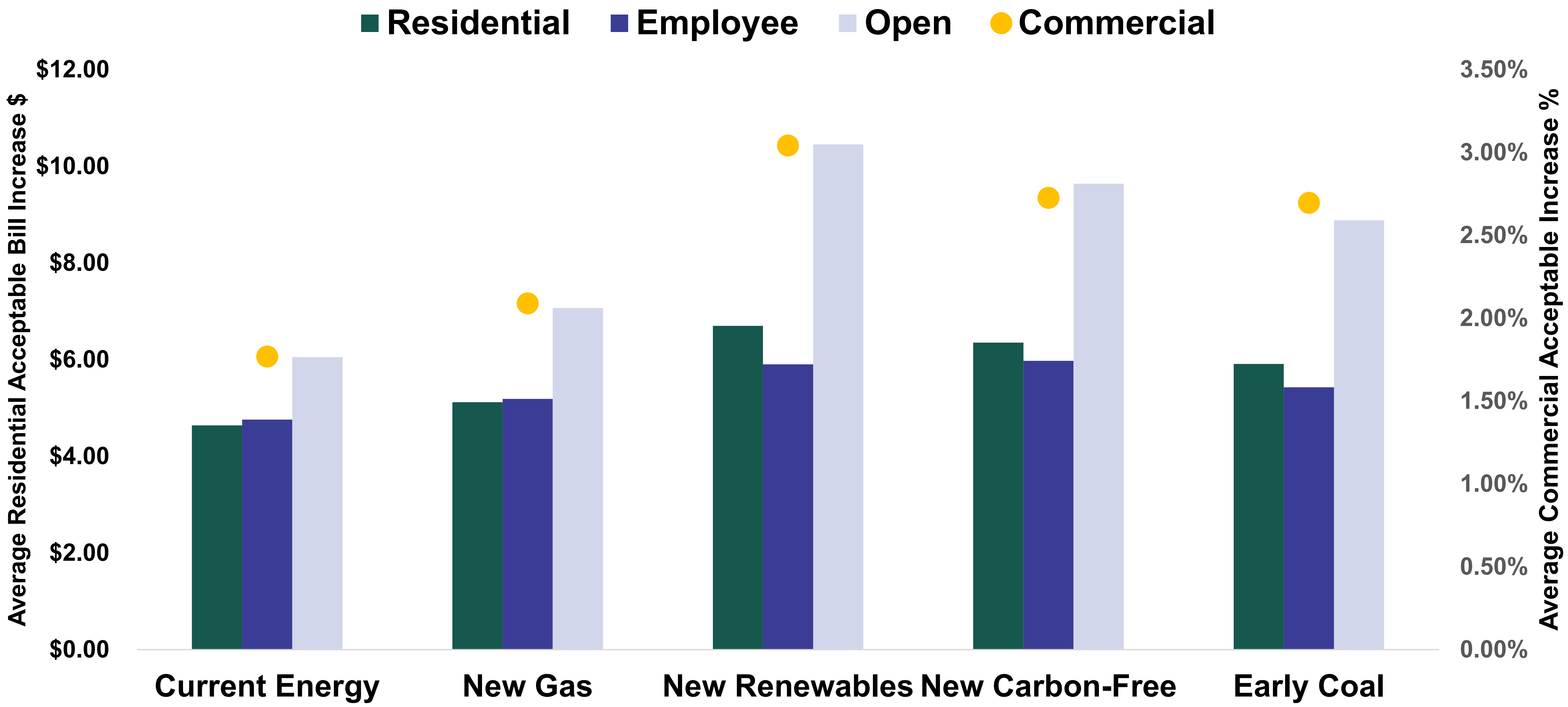
- Preferred Pathway: Current Energy Resources
- Chosen Pathway Bill Impact: 32% no increase; 29% $10 or more
- Emissions Approach: Gradual
- DSM Responsibility: Individuals at 55%

Open

- Preferred Pathway: New Renewable Resources
- Chosen Pathway Bill Impact: 16% no increase and 31% $15 or more
- Emissions Approach: Higher Impact
- DSM Responsibility: Colorado Springs Utilities at 33%

Acceptable Bill Increase

IRP Survey Results



Source: 2020 Integrated Resource Plan Phase 3 Survey – All Segments

Pathway Preference

Question: Of the five pathways presented, which do you prefer?

	Residential	Commercial	Employee	Open
Current Energy	16%	27%	35%	12%
New Gas – Pathway B	8%	9%	17%	5%
New Renewable – Pathway C	45%	38%	27%	47%
New Carbon Free – Pathway D	17%	12%	12%	18%
Early Coal Retirement – Pathway E	14%	15%	9%	18%

Similarities:

- New Renewables was most preferred by Residential and Open survey respondents
- New Gas pathway had the lowest preference

Differences:

- Employee respondents chose the Current Energy pathway as most preferred
- Employee respondents have the highest preference for new gas resources
- Commercial respondents chose Current Energy pathways as second preference

Pathway Influence

Question: Which of the following influenced you to select this pathway? Please select all that apply.

	Residential	Commercial	Employee	Open
Environmental Goals	62%	52%	43%	72%
New Energy Resources	42%	40%	38%	38%
Power Plant Retirement	27%	32%	32%	40%
Regulatory Requirement Levels	17%	24%	25%	14%

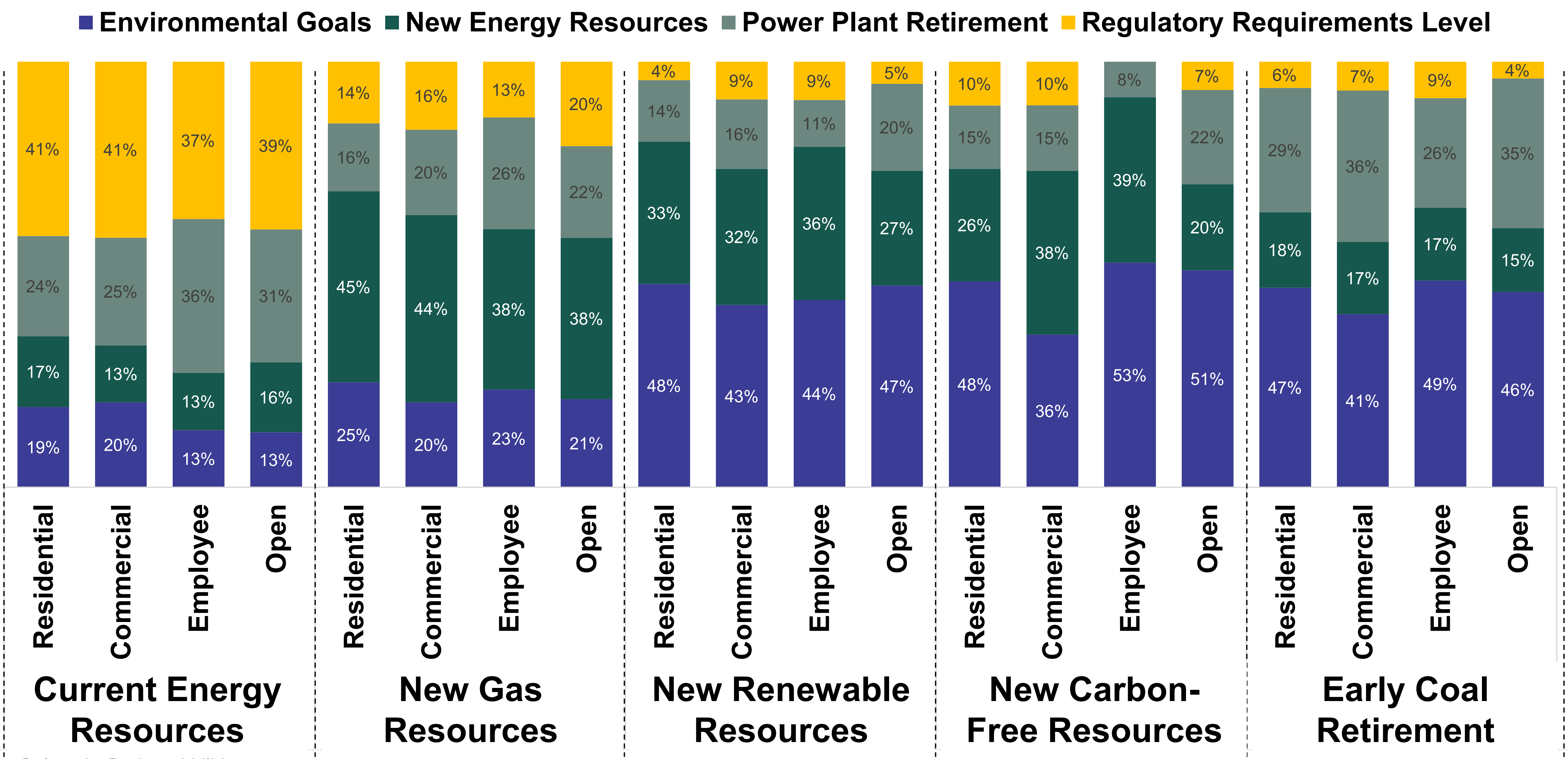
Similarities:

- Environmental Goals had the most influence on respondents' selected pathway

Differences:

- Environmental Goals and Power Plant Retirement had a more significant influence for Open than the other segments

Influence of Preference by Pathway – All Segments



Carbon Emissions Approach

Question: Given the state legislation requirement of decreasing carbon emissions by at least 90% by 2050, what approach should Colorado Springs Utilities take?

	Residential	Commercial	Employee	Open
Gradual Impact	33%	46%	46%	19%
Moderate Impact	44%	34%	40%	30%
High Impact	23%	20%	13%	51%

Similarities:

- Moderate was selected either 1 or 2 in all segments
- Higher Impact approach was chosen as last in 3 out of 4 segments

Differences:

- Commercial and Employee respondents selected a more gradual approach
- Open respondents selected a more aggressive approach

Energy Savings Responsibility

*Question: Please indicate which of the following is **most responsible** for energy saving efforts.*

	Residential	Commercial	Employee	Open
Individuals	40%	37%	55%	26%
Colorado Springs Utilities	22%	29%	22%	33%
Local/State Government	21%	14%	11%	25%
Federal Government	11%	8%	3%	12%
Local Businesses	5%	10%	7%	3%
Community Organization	1%	3%	1%	2%

Similarities:

- Residential, Commercial, and Employees named Individuals

Differences:

- Open said Colorado Springs Utilities is the most responsible
- Employees placed the highest responsibility on the individual

Energy Efficiency and Planning Relationship

Question: Using a scale from 1 to 10, how important is customer efficiency/renewable energy efforts in energy planning?

	Residential	Commercial	Employee	Open
Index	7.90	7.10	7.13	8.20

Similarities:
- All segments believed energy planning should include customer efficiency/renewable efforts

Differences:
- Open segment placed more emphasis on customer efforts
- Commercial placed less emphasis on customer efforts

Post-Survey Events

- Probable state regulations for emission standards by utilities were presented after survey was executed
- Portfolio for 100% renewable was not included in survey
- Net Present Value (NPV) of portfolios was unknown
- UPAC reduced the portfolios from 20 to 12
- Attribute weighting finalized by the Utilities Board

Conclusion

Community Outreach Summary

- When customer evaluated which portfolio they would be willing to accept a <u>larger bill impact,</u> they chose Pathways C, D and E in that order. All segments selected the prioritized in the same order.
- Pathway C was the most favorable pathway for the community.
- Customers are looking for solutions to achieve Environmental Goals and look for New Energy Resources (i.e. Pathways C, D, and E)
- Pathways C and D were selected because of the Environmental Goals and New Energy Resources efforts.
- Pathway E was selected for reasons of Environmental Goals and Power Plant Retirement considerations.
- Customers value the importance of demand side management for energy planning
- A moderate approach to reducing emissions is acceptable to all segments.

Portfolios with Scoring, Financial Results, Sensitivities and Risks

	Portfolio	Carbon Targets	2023	2026	2030	2035	2040	2050
Reference Case *Drake Retired in 2035*	R					Drake & Birdsall Retire Gas		
	1	80% Carbon by 2030 90% Carbon by 2050				Drake & Birdsall Retire Gas/Renewable/Storage		
Pathway A *50% Carbon Reduction by 2030*	2	50% Carbon by 2030 90% Carbon by 2050			Drake 6 & 7 Retire Gas & DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
	6	50% Carbon by 2030 90% Carbon by 2050			Drake 6 & 7 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
Pathway B *Gas & DSM Replacement Generation*	3	50% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM		Birdsall 1-3 Retire Renewable/Storage/DSM		Nixon 1 Retire Gas & DSM
	4	50% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM		Birdsall 1-3 Retire Renewable/Storage/DSM	Nixon 1 Retire Gas & DSM	
	5	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM	Nixon 1 Retire Gas & DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
	13	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM	Nixon 1 Retire Gas & DSM	Birdsall 1-3 Retire Gas & DSM		
Pathway C *Renewable and DSM Replacement Generation*	7	50% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM		Birdsall 1-3 Retire Renewable/Storage/DSM		Nixon 1 Retire Renewable/Storage/DSM
	8	50% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM		Birdsall 1-3 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	
	9	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
	10	80% Carbon by 2030 100% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		Front Range Nixon CT Retire Renewable/Storage/DSM
	14	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
Pathway D *Carbon Free*	11	80% Carbon by 2030 100% Carbon by 2050		Drake 6 & 7 Retire Non-Carbon/Storage/DSM	Nixon 1 Retire Non-Carbon/Storage/DSM	Birdsall 1-3 Retire Non-Carbon/Storage/DSM		Front Range Nixon CT Retire Non-Carbon/Storage/DSM
Pathway E *Early Coal Decommission*	12	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas	Nixon 1 Retire Gas/Renewable/Storage/DSM		Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	16	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Gas/Renewable/Storage/DSM	Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	17	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Non-Carbon/Storage/DSM	Birdsall 1-3 Retire Non-Carbon/Storage/DSM		
Pathway F *100 % Renewable*	15	100% Renewable by 2030			Drake 6 & 7 Nixon 1,2,3 Retire Front Range Birdsall Renewable/Storage/DSM			
	18	100% Renewable by 2040				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM	Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM	
	19	100% Renewable by 2050				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM		Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM

Portfolio	CO2 Target	Retirements	New Resources	Attribute Ranking	Reliability	Cost/ Implementation	Environment/ Stewardship	Flexibility /Diversity	Innovation
4	50% by 2030 90% by 2050	Drake 2026 Nixon 1 2040	Gas/Renewable/Storage/DSM	1	93	100	57	50	60
13*	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Gas/DSM	2	100	96	80	25	30
17	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	3	100	46	69	88	70
16	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	4	93	63	72	75	50
14*	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Renewable/Storage/DSM	5	73	79	69	75	70
12	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2026	Aeroderivative/Gas/Renewable/Storage/DSM	6	93	63	69	75	50
10	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Renewable/Storage/DSM	7	80	30	81	100	100
2	50% by 2030 90% by 2050	Drake 2030	Gas/Renewable/Storage/DSM	8	87	100	53	50	40
3	50% by 2030 90% by 2050	Drake 2026 Nixon 1 2050	Gas/Renewable/Storage/DSM	9	80	100	53	38	60
11	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Non-Carbon/Storage/DSM	10	87	30	84	88	60
6	50% by 2030 90% by 2050	Drake 2030	Renewable/Storage/DSM	11	60	84	46	88	80
7	50% by 2030 90% by 2050	Drake 2026 Nixon 1 2050	Renewable/Storage/DSM	12	60	84	50	100	50
8	50% by 2030 90% by 2050	Drake 2026 Nixon 1 2040	Renewable/Storage/DSM	13	73	67	50	100	50
R	N/A	Drake 2035	Gas	14	80	88	38	75	30
5	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Gas/Renewable/Storage/DSM	15	73	63	76	25	50
15	100% by 2030	Drake/Nixon/Front Range 2030	Renewable/Storage/DSM	16	73	21	100	50	60
9	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Renewable/Storage/DSM	17	60	30	69	100	50
18	100% by 2040	Drake 2035 Nixon/Front Range 2040	Renewable/Storage/DSM	18	80	30	53	50	60
1	80% by 2030 90% by 2050	Drake 2035	Gas/Renewable/Storage	19	53	55	61	50	40
19	100% by 2050	Drake 2035 Nixon/Front Range 2050	Renewable/Storage/DSM	20	73	38	38	63	30

*Regional Market

Birdsall Retired in 2035 in all Portfolios except Portfolio 15 which is 2030.

Green = Highest Score
Yellow = Lowest Score
Blue = No longer being considered by UPAC

	Portfolio	Carbon Targets	2023	2026	2030	2035	2040	2050
Reference Case *Drake Retired in 2035*	R					Drake & Birdsall Retire Gas		
	1	80% Carbon by 2030 90% Carbon by 2050				Drake & Birdsall Retire Gas/Renewable/Storage		
Pathway B Gas & DSM Replacement Generation	5	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM	Nixon 1 Retire Gas & DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
Pathway C Renewable and DSM Replacement Generation	9	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
	10	80% Carbon by 2030 100% Carbon by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		Front Range Nixon CT Retire Renewable/Storage/DSM
Pathway D *Carbon Free*	11	80% Carbon by 2030 100% Carbon by 2050		Drake 6 & 7 Retire Non-Carbon/Storage/DSM	Nixon 1 Retire Non-Carbon/Storage/DSM	Birdsall 1-3 Retire Non-Carbon/Storage/DSM		Front Range Nixon CT Retire Non-Carbon/Storage/DSM
Pathway E *Early Coal Decommission*	12	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas	Nixon 1 Retire Gas/Renewable/Storage/DSM		Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	16	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Gas/Renewable/Storage/DSM	Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	17	80% Carbon by 2030 90% Carbon by 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Non-Carbon/Storage/DSM	Birdsall 1-3 Retire Non-Carbon/Storage/DSM		
Pathway F *100 % Renewable*	15	100% Renewable by 2030			Drake 6 & 7 Nixon 1,2,3 Retire Front Range Birdsall Renewable/Storage/DSM			
	18	100% Renewable by 2040				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM	Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM	
	19	100% Renewable by 2050				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM		Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM

Draft Gas Portfolios to Support EIRP

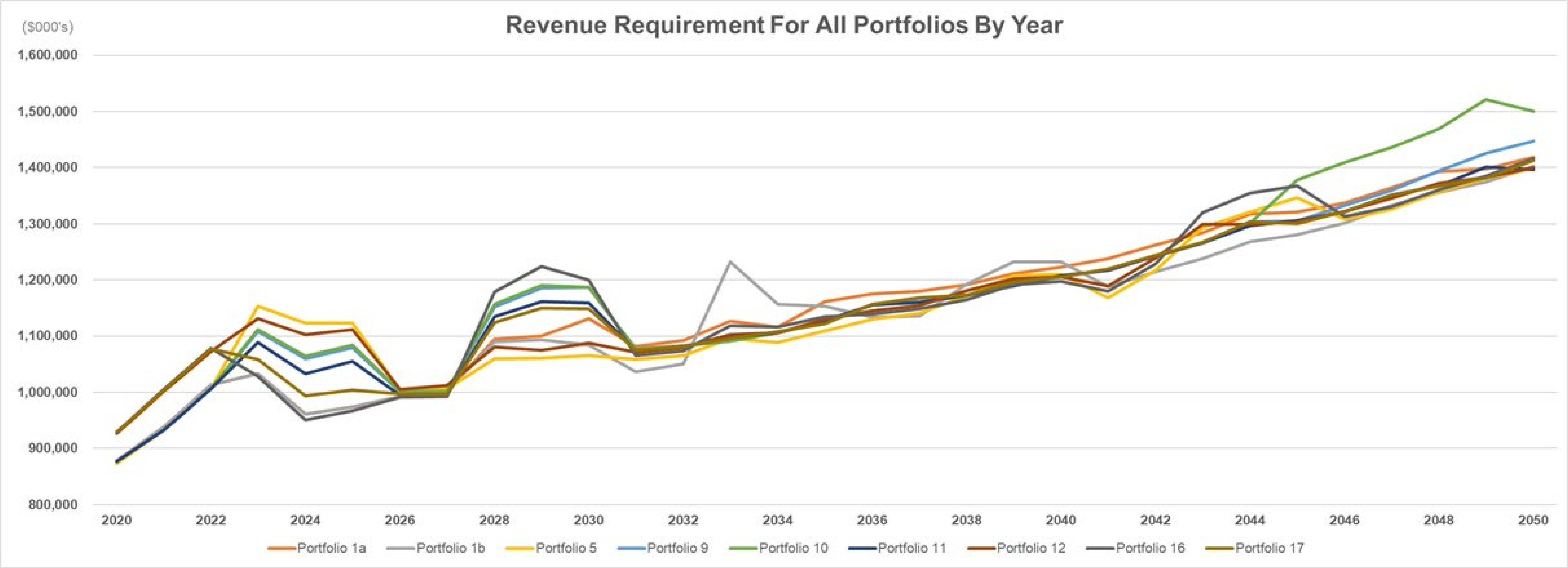
	Portfolio	2022	2025	2030	2032	2034	2035	2040	2043	2050
Gas Reference Case	G1				**Propane Air Expansion**	**Propane Air New**		**Expand Propane Air**		
EIRP Reference Case	G-E1				LDC IT with Oil Backup		Expand/New Pipeline Capacity + NNT			
	G-ER			LDC IT with Oil Backup			Expand / New Pipeline Capacity + NNT	Expand / New Pipeline Capacity + NNT		
EIRP Pathway B	G-E5		LDC IT with Oil Backup Expand / New Pipeline Capacity + NNT							
EIRP Pathway C	G-E9,10									
EIRP Pathway D	G-E11									Expand / New Pipeline Capacity + NNT
EIRP Pathway E	G-E12	LDC IT with Oil Backup	Expand / New Pipeline Capacity + NNT							
	G-E16	LDC IT with Oil Backup	Expand / New Pipeline Capacity + NNT	Expand / New Pipeline Capacity + NNT						
	G-E17	LDC IT with Oil Backup	Expand / New Pipeline Capacity + NNT							
EIRP Pathway F	G-E19			Expand / New Pipeline Capacity + NNT						

IRP Financial Model Results – Revenue Requirements

Red numbers in parentheses indicate lower revenue requirements.

30 Year Average Revenue Requirement Compared to Portfolio 1a	
Portfolios	**30 Year Annual Revenue Requirement ($000's)**
Portfolio 1a 80% by 2030 (Reference Case)	1,171,308
Portfolio 1b No CO2 Reg (Reference Case)	(14,892)
Portfolio 5 (Drake 2026/Nixon 2030 retire, New Gas & DSM)	(6,926)
Portfolio 9 (Drake 2026/Nixon 2030 retire, New Renewables/Storage/DSM)	8,219
Portfolio 10 (Drake 2023/Nixon 2026 retire, New Gas/Renewables/Storage/DSM)	23,830
Portfolio 11 (Drake 2026/Nixon 2030/FR 2050 retire, New Carbon-Free/DSM)	(1,228)
Portfolio 12 (Drake 2023/Nixon 2026 retire, New Gas/Renewables/Storage/DSM)	2,512
Portfolio 15 (100% Renewable by 2030)	TBD
Portfolio 16 (Drake 2023/Nixon 2030 retire, New Gas/Renewables/Storage/DSM)	2,816
Portfolio 17 (Drake 2023/Nixon 2030 retire, New Gas/Carbon-Free/DSM)	(1,087)
Portfolio 18 (100% Renewable by 2040)	TBD
Portfolio 19 (100% Renewable by 2050)	TBD

IRP Financial Model Results – Revenue Requirements



IRP Financial Model Results - Metrics

Red numbers indicate metrics that could require rate increases.

30 Year Average Annual Financial Metrics with Minimum and Maximum 3 Year Average For Each Portfolio						
	30 Year Average	3 Year Average	3 Year Average	30 Year Average	3 Year Average	3 Year Average
	Adjusted Debt Service Coverage	Minimum ADSC	Maximum ADSC	Days Cash On Hand	Minimum DCH	Maximum DCH
Portfolio 1a 80% by 2030 (Reference Case)	1.92	1.73	2.20	157	149	195
Portfolio 1b No CO2 Reg (Reference Case)	2.21	1.66	2.89	163	145	191
Portfolio 5 (Drake 2026/Nixon 2030 retire, New Gas & DSM)	2.43	1.64	3.44	180	144	217
Portfolio 9 (Drake 2026/Nixon 2030 retire, New Renewables/Storage/DSM)	1.75	1.45	1.93	147	115	176
Portfolio 10 (Drake 2023/Nixon 2026 retire, New Gas/Renewables/Storage/DSM)	1.65	1.05	1.93	128	(15)	176
Portfolio 11 (Drake 2026/Nixon 2030/FR 2050 retire, New Carbon-Free/DSM)	2.02	1.69	2.42	152	145	176
Portfolio 12 (Drake 2023/Nixon 2026 retire, New Gas/Renewables/Storage/DSM)	2.20	1.59	2.80	151	144	159
Portfolio 15 (100% Renewable by 2030)	TBD	TBD	TBD	TBD	TBD	TBD
Portfolio 16 (Drake 2023/Nixon 2030 retire, New Gas/Renewables/Storage/DSM)	2.47	1.70	3.47	203	145	269
Portfolio 17 (Drake 2023/Nixon 2030 retire, New Gas/Carbon-Free/DSM)	1.89	1.66	2.04	150	144	160
Portfolio 18 (100% Renewable by 2040)	TBD	TBD	TBD	TBD	TBD	TBD
Portfolio 19 (100% Renewable by 2050)	TBD	TBD	TBD	TBD	TBD	TBD

* Note Average Debt Ratio for all Portfolios meets acceptal levels to maintain Bond Rating

Portfolio	CO2 Target	Retirements	New Resources	Attribute Ranking	Reliability	Cost/ Implementation	Environment /Stewardship	Flexibility /Diversity	Innovation
17	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	1	100	46	69	88	70
16	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	2	93	63	72	75	50
12	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2026	Aeroderivative/Gas/Renewable/Storage/DSM	3	93	63	69	75	50
10	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Renewable/Storage/DSM	4	80	30	81	100	100
11	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Non-Carbon/Storage/DSM	5	87	30	84	88	60
R	N/A	Drake 2035	Gas	6	80	88	38	75	30
5	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Gas/Renewable/Storage/DSM	7	73	63	76	25	50
15	100% by 2030	Drake/Nixon/Front Range 2030	Renewable/Storage/DSM	8	73	21	100	50	60
9	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Renewable/Storage/DSM	9	60	30	69	100	50
18	100% by 2040	Drake 2035 Nixon/Front Range 2040	Renewable/Storage/DSM	10	80	30	53	50	60
1	80% by 2030 90% by 2050	Drake 2035	Gas/Renewable/Storage	11	53	55	61	50	40
19	100% by 2050	Drake 2035 Nixon/Front Range 2050	Renewable/Storage/DSM	12	73	38	38	63	30

Birdsall Retired in 2035 in all Portfolios except Portfolio 15 which is 2030.

Green = Highest Score
Yellow = Lowest Score

Draft Gas Portfolios to Support LDC

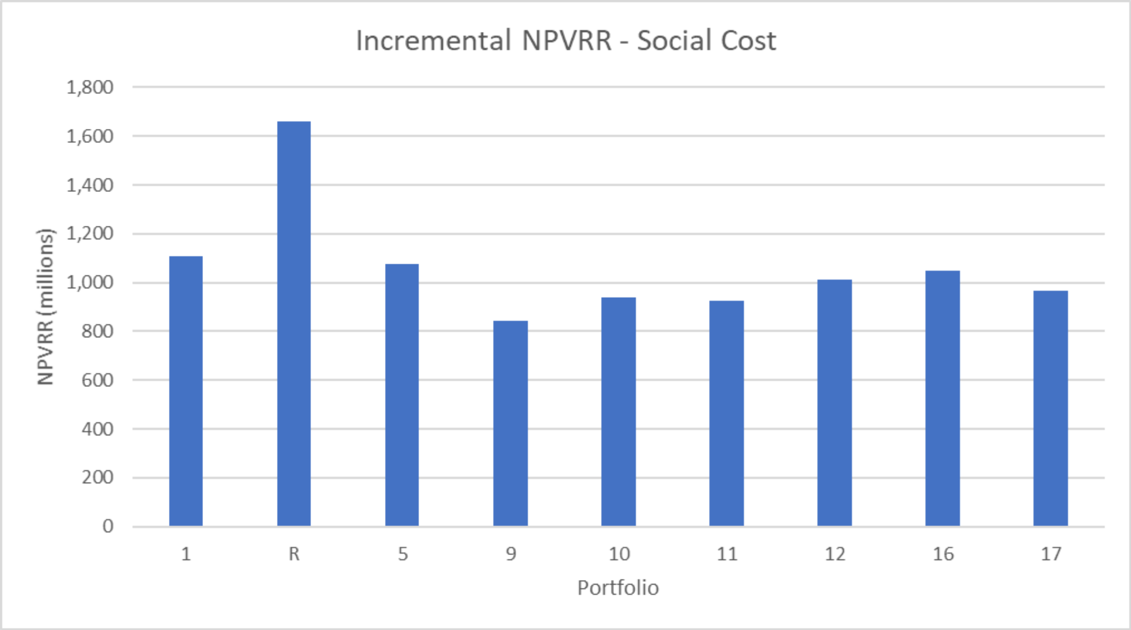
	Portfolio	2022	2025	2030	2032	2034	2035	2040	2043	2050
Gas Reference Case	G-1				Propane Air Expansion - Y2032	Propane Air New Y2034		Expand Propane Air Y2040		
Pathway A New Pipeline Capacity	G-2				Propane Air Expansion - Y2032	Expand/New Pipeline Capacity - Y2034				
Pathway B New Peak Shaving Capacity	G-3				Propane Air Expansion - Y2032	New LNG Plant Y2034			Expand LNG Plant Y2041	
Pathway C DSM + New Peak Shaving Capacity	G-4		Demand Response Y2025 to Y2044		Propane Air Expansion - Y2032			Propane Air New Y2039		Expand Propane Air Y2047
	G-5		Energy Efficiency Y2025 to Y2044		Propane Air Expansion - Y2032	Propane Air New Y2034			Expand Propane Air Y2043	
	G-6		DR + EE Y2025 to Y2044		Propane Air Expansion - Y2032			Propane Air New Y2040		

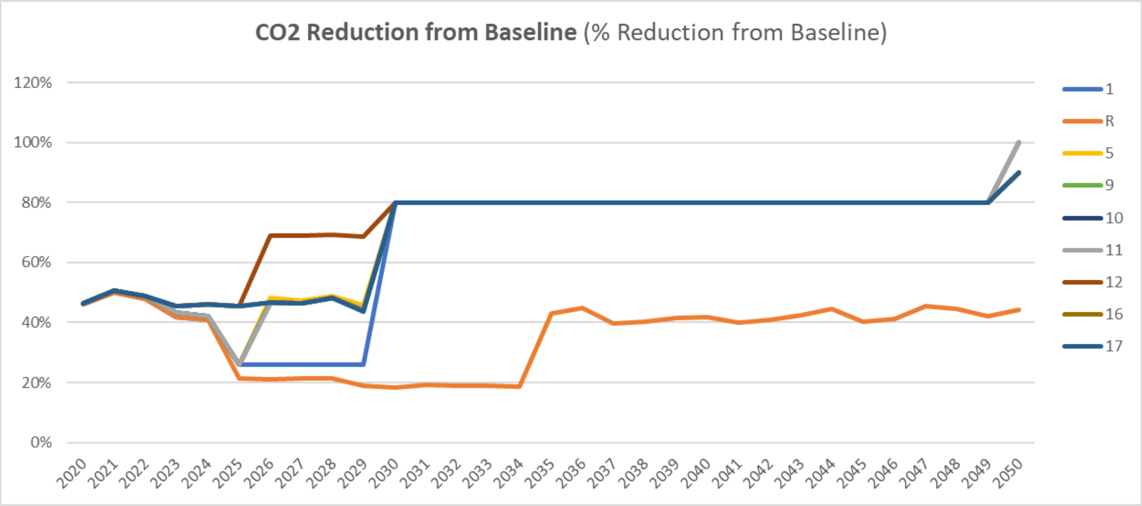
Results of Key Sensitivities

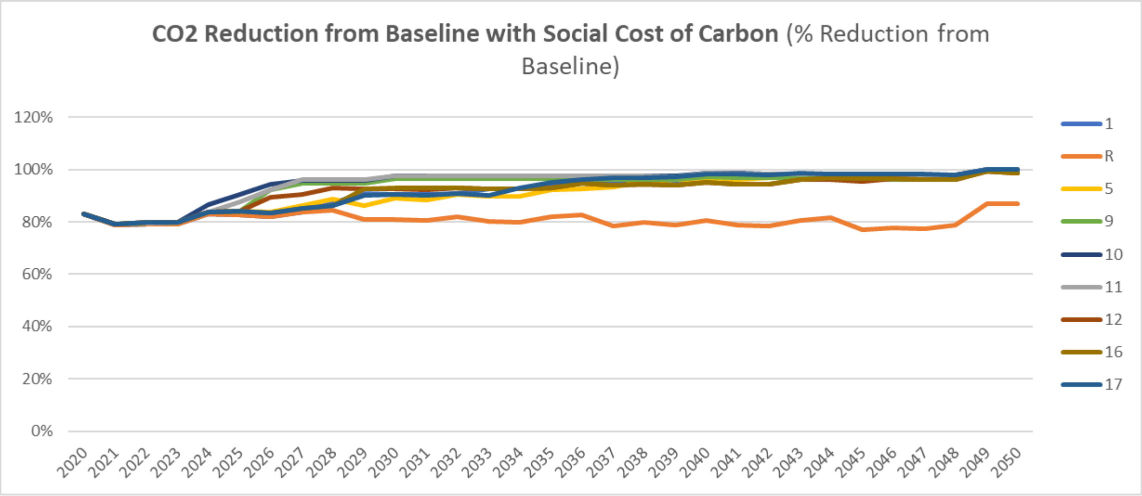
Portfolio	CO2 Target	Retirements	New Resources	High Gas	Low Gas	No Energy Purchases	90x30	100x50	Drake 2022	High Load	Low Load	CO2 on Purchases	Low Renewable Cost
1	80% by 2030 90% by 2050	Drake 2035	Gas/Renewable/Storage	382	-471	269	169	115	N/A	373	-276	194	-39
R	N/A	Drake 2035	Gas	410	-389	58	N/A	N/A	N/A	279	-253	50	N/A
5	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Gas/Renewable/Storage/DSM	492	-498	181	208	117	N/A	306	-283	156	-2
9	80% by 2030 90% by 2050	Drake 2026 Nixon 1 2030	Renewable/Storage/DSM	406	-547	510	140	0	N/A	370	-366	169	-126
10	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Renewable/Storage/DSM	387	-511	514	162	N/A	N/A	333	-321	223	-174
11	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Non-Carbon/Storage/DSM	484	-466	336	165	N/A	N/A	401	-374	170	-69
12	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2026	Aeroderivative/Gas/Renewable/Storage/DSM	579	-554	220	183	166	-14	277	-291	231	-8
16	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	535	-482	207	217	193	-13	308	-238	200	-1
17	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	458	-490	163	98	100	-55	330	-317	127	-96

Note: Numbers are incremental NPVRR in millions of dollars.

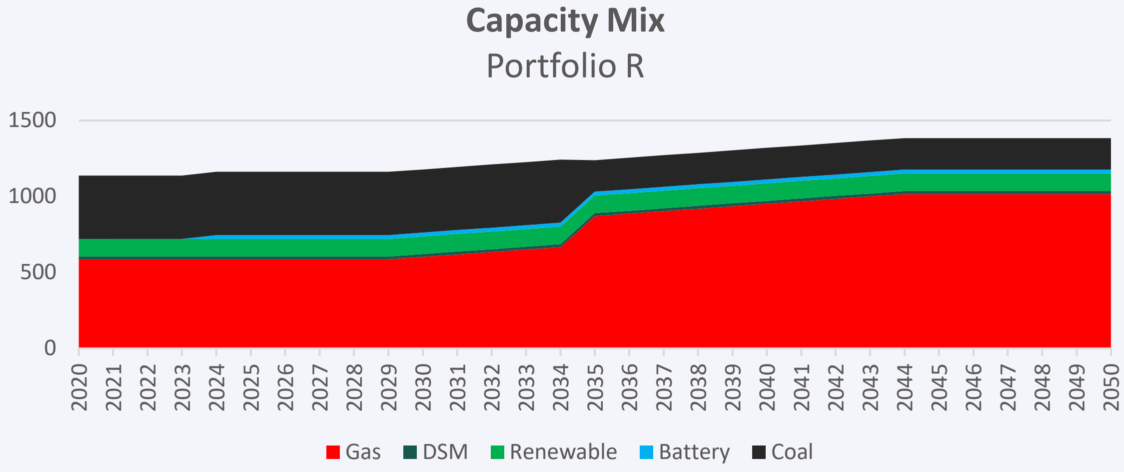
Social Cost Sensitivity

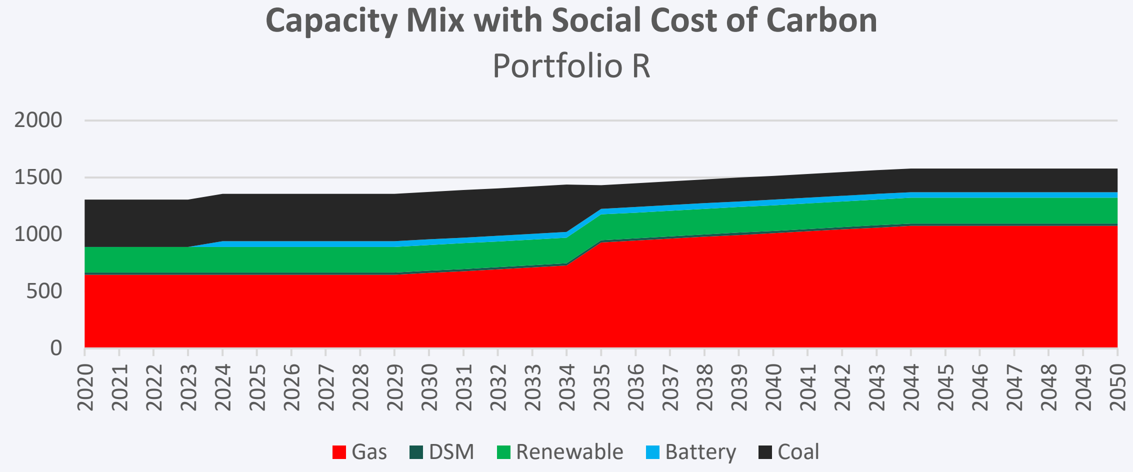


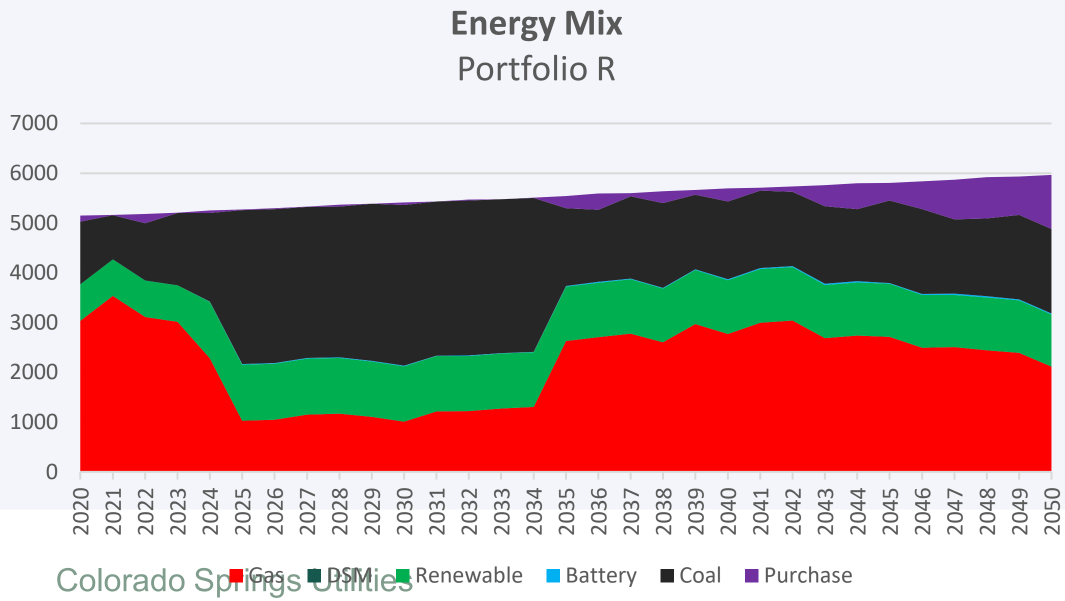


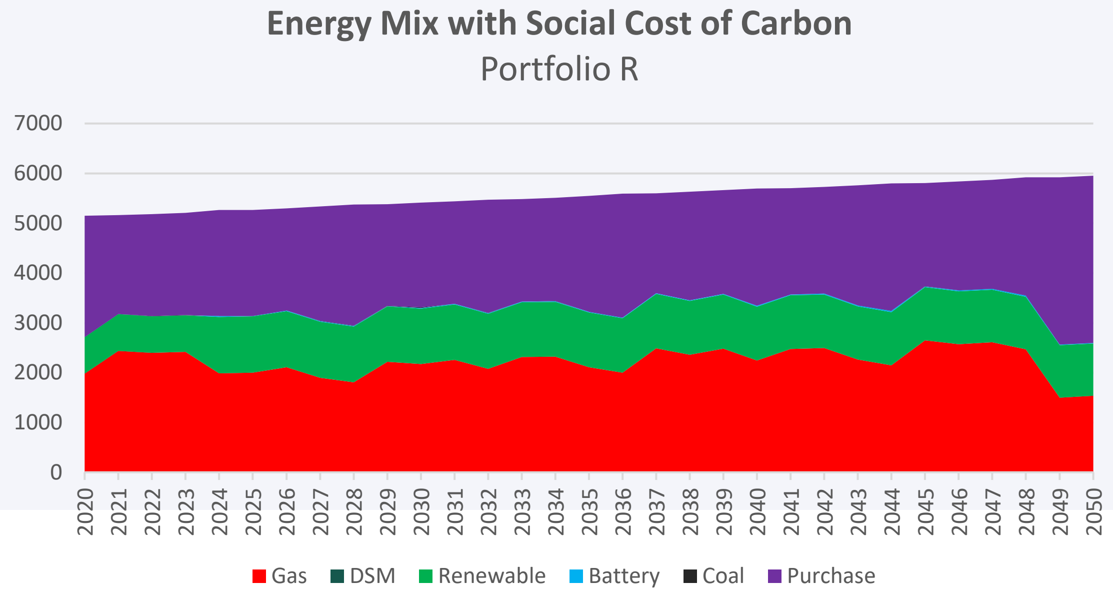


Social Cost Sensitivity (cont'd)









Key EIRP Sensitivities Takeaways

Sensitivity	Takeaway
Gas Prices	Impact not only portfolios with gas but also renewables because it impacts cost of market purchases. Low gas prices help all portfolios. High gas prices hurt all portfolios.
Energy Purchases	Limiting energy purchases increases the cost of portfolios and impacts renewable only portfolios the most because overbuild is required to maintain reliability.
Regional Market	Opportunity to lower costs through regional market that would lower transmission and renewable integration costs.
90% by 2030	All portfolios are more costly and increases reliance on energy market.
100% by 2050	All portfolios are more costly. Model still builds gas generation as a bridge allowing for cost of renewables to continue declining over time.
Drake 2022 retirement	Additional capacity is needed sooner. Can lower costs even more depending on capacity resource.
High load/Electrification /Annexation	All portfolios are more costly but could reduce GIRP costs.
Low load	All portfolios are less costly

Key EIRP Sensitivities Takeaways (cont'd)

Sensitivity	Takeaway
Social Cost of Carbon	Increases cost of all portfolios substantially. Gas resources still built but do not run much. This is still more cost effective than overbuild of renewables to meet capacity requirements.
CO2 rate on energy purchases	All portfolios are more costly. In the base model runs, no CO2 emissions are applied to market purchases so all portfolios rely on them to serve growing load while meeting CO2 targets.
Birdsall early retirement	All portfolios are more costly as that is additional capacity needed on top of Drake and Nixon retirements in short time period.
DSM	There are economic benefits from both Energy Efficiency and Demand Response programs. However, you do reach a point of diminishing returns.
Transmission costs	All portfolios are more costly. If there are increased transmission costs for resources such as wind, the model tends to pick solar over wind because the costs are pretty close otherwise.
Lower Renewable and Storage prices	All portfolios are less costly. Still builds small amounts of gas capacity.

100% Renewable Study Sensitivities

Scenario	Description	NPV ($M)	Takeaways
1a	Reference Case	$3,824	No GHG regulations assumed
2a	100% Renewable Energy for 2030, no energy purchases or sales	$12,467	Current transmission infrastructure is not sufficient to get to 100% renewable energy. Cost of implementing renewable generation targets does not include transmission infrastructure costs. Excess energy and hours of curtailment. Significant amount of battery storage needed exceeding 3,000 MW capacity for each portfolio. Battery storage utilization exceeds 1 cycle per day, which could impact the life time of the battery. Energy curtailment expected between 150 – 900 GWh. An average demand response utilization rate of 5% could be required to maintain reliability.
3a	100% Renewable Energy for 2040, no energy purchases or sales	$9,797	
4a	100% Renewable Energy for 2050, no energy purchases or sales	$5,694	
5a	100% Carbon Free for 2050	$6,184	2,250 MW of battery capacity required. Less utilization rate that 100% portfolios 2-4. Lower DR utilization rate than portfolios 2-4.
6a	100% Renewable Energy for 2050 in an RTO	$5,483	Portfolios have the ability to purchase energy or sell energy in lieu of curtailment will result in a lower cost portfolio. Less nameplate capacity is required as energy purchases can contribute to lowering the loss of load expectation. Regional Transmission Organization (RTO) provide an opportunity to access diverse power supply and transmission reliability coordination.
7a2	100% Renewable Energy for 2030 with No Import / Export Constraints	$6,518	
7a3	100% Renewable Energy for 2040 with No Import / Export Constraints	$6,302	
7a4	100% Renewable Energy for 2050 with No Import / Export Constraints	$4,667	
7a5	100% Carbon Free for 2050 with No Import / Export Constraints	$4,131	
8a	80% Renewable Energy for 2050	$5,276	Less battery and renewable capacity build to comply with renewable/CO2 targets. Lower utilization of demand response.
9a	60% Renewable Energy for 2050	$4,591	
10a	90% CO2 Reduction in 2050	$5,415	

Key GIRP Sensitivities Takeaways

Sensitivity	Takeaway

Pathway Risks

Pathway	Portfolios	Risk	Mitigation
Reference Case	1A, 1B	a) Regulatory Risk b) Potential Stranded Asset	a) Select portfolio that complies with 80% GHG reduction by 2030 b) Decommission Drake and Nixon 1 prior to 2030
Pathway B *Gas & DSM Replacement Generation*	5	a) Electrification will provide a challenge in serving increased load while reducing GHG emissions b) Future regulatory risk (ex. 100% renewables) c) Reliance on the market purchases to reduce GHG d) High Commodity Prices	a) Ramp up renewable, battery, and DSM programs prior to anticipated year of need b) Allow Drake's replacement to include gas resources to limit likelihood of a stranded asset c) Increase energy efficiency and renewable generation d) Increase energy efficiency and renewable generation
Pathway C *Renewable and DSM Replacement Generation*	9, 10	a) Overbuild needed to maintain reliability b) Reliance on energy purchases to maintain reliability c) Transmission import limitations for wind generation d) Reliance on Demand Response	a) Consider backup/firming resources such as gas and battery b) Consider backup/firming resources such as gas and battery, Perform a renewable potential study to determine potential for Hydro, Biomass, Geothermal, Pump Storage near Colorado Springs c) Perform transmission study to determine projects needed to facilitate increasing wind generation. Ramp up solar, battery, and energy efficiency in the interim. Evaluate regional market opportunities. d) Plan to displace future capacity once demand response programs have been tested and validated for availability
Pathway D *Carbon Free*	11	a) Carbon Capture may not be ideal for CSU's location b) Modular Nuclear resources have limited operation in the US c) Regulatory risk permitting modular nuclear	a) Potential study to determine feasibility of Carbon Capture b) Allow time for technology to mature, do not plan for the Drake or Nixon to be replaced by modular nuclear. Near-term resources will should include wind, solar, battery, and demand side management c) Start permitting process far in advance of anticipated need
Pathway E *Early Coal Decommission*	12, 16,17	a) Tight on capacity with early drake decommissioning b) Electrification will provide a challenge in serving increased load while reducing GHG emissions c) Future regulatory risk (ex. 100% renewables) d) Transmission import limitations for wind generation	a) Market purchase, add another aeroderivative resource, or increase pike battery to 50 MW b) Ramp up renewable, battery, and DSM programs prior to anticipated year of need c) Allow Drake's replacement to include gas resources to limit likelihood of a stranded asset d) Perform transmission study to determine projects needed to allow for the delivery of wind generation. Evaluate regional market opportunities. e) Increase energy efficiency and renewable generation
Pathway F *100% Renewable*	15, 18, 19	a) Project coordination and implementation b) Transmission import limitations for wind generation c) Low availability for certain resources d) Reliance on Demand Response e) Overbuild needed to maintain reliability f) Reliance on energy purchases to maintain reliability	a) Allow for time to implementation and analysis. b) Perform transmission study to determine projects needed to allow for the delivery of wind generation. Evaluate regional market opportunities. Ramp up solar, battery, and energy efficiency in the interim. c) Perform a renewable potential study to determine potential for Hydro, Biomass, Geothermal, Pump Storage near Colorado Springs d) Plan to displace future capacity once demand response programs have been tested and validated for availability. e) Consider backup/firming resources such as gas and battery, Perform a renewable potential study to determine potential for Hydro, Biomass, Geothermal, Pump Storage near Colorado Springs

Risk by Attribute

Pathway	Portfolio	Reliability	Cost/Implementation	Environmental/Stewardship	Flexibility/Diversity	Innovation
Reference Case	1A	L	L	H	H	H
	1B	L	L	H	H	H
Pathway B *Gas & DSM Replacement Generation*	5	L	L	M	M	L
Pathway C *Renewable and DSM Replacement Generation*	9	M	M	M	M	L
	10	H	M	M	M	L
Pathway D *Carbon Free*	11	M	M	M	M	M
Pathway E *Early Coal Decommission*	12	M	L	M	L	L
	16	M	L	M	L	L
	17	M	M	L	M	L
Pathway F *100% Renewable*	15	H	H	L	H	H
	18	H	H	L	H	M
	19	M	M	L	L	L

More groundwork is needed to increase renewable and non-carbon generation

Solar	Wind	Hydro / Pump Storage	Biomass / Biogas / Landfill Gas / Geothermal	Nuclear / CC with Carbon Capture
Additional Battery or quick response resources	Transmission Study[1] RFP for that includes wind delivery strategy Additional Battery or quick response resources To ramp up large quantities of wind, either enter into a Regional Transmission Organization (RTO) or complete transmission projects identified in transmission study	Evaluate implications of hydro and pump storage to water supply through Water Integrated Resource Plan (WIRP) Use learnings to from WIRP to develop assumptions in future EIRP	Potential study to determine the availability of each resource in Colorado Springs and surrounding arear Potential location dependent resources, either enter into a Regional Transmission Organization (RTO) or complete transmission projects identified in transmission study Use learnings from potential Study to develop assumptions in future EIRP	Allow for time for modular nuclear resources to mature Commission feasibility study to determine if carbon can be stored or reasonable be transported from Colorado Springs Potential location dependent resources, either enter into a Regional Transmission Organization (RTO) or complete transmission projects identified in transmission study

Seek partnership opportunities to develop renewable and import projects outside of Colorado Springs

1. Transmission study could be focused on wind, or it could include transmission needed once locations determined from biomass/biogas/landfill gas/geothermal/carbon capture potential studies are completed

IRP Workshop and Workbook

Workshop Agenda (draft)

- Welcome by Jill Gaebler
- Summary of UPAC Energy Vision and IRP Assignments by Rex Adams
- Legislative Overview by Andy Colosimo
- Detailed IRP Review including UPAC Recommendations
- Board Discussion
- Future Discussion Topics after IRP

Virtual Workbook

- History
  - All past presentations in date order
  - Summary of activity for each meeting held related to IRP (for example, Energy Vision was approved at x meeting on x date)
- Summary of each portfolio
  - 1 page description (example in next slide)
  - All graphs/charts
- Public process information, including survey results
  - Dates/activity/etc.

Portfolio Single Page Summary

- Description – high level in simple language
- Attribute scores and total score
  - Listed in order, high score to low
- Resource Mix
- CO_2 reduction
- Financial Results
- Key Sensitivities Results
- Gas Capacity Expansion Plan
- Risks

Recommendation to Utilities Board

	Portfolio	Attainable Carbon Goals	2023	2026	2030	2035	2040	2050
Reference Case	1A	80% Carbon by 2030 90% Carbon by 2050				Drake & Birdsall Retire Gas/Renewable/Storage		
	1B					Drake & Birdsall Retire Gas		
Pathway B Gas & DSM Replacement Generation	5	80% Carbon by 2030 90% Carbon by 2050		Drake 6 & 7 Retire Gas & DSM	Nixon 1 Retire Gas & DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
Pathway C Renewable and DSM Replacement Generation	9	80% Carbon by 2030 100% Renewable by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		
	10	80% Carbon by 2030 100% Renewable by 2050		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1 Retire Renewable/Storage/DSM	Birdsall 1-3 Retire Renewable/Storage/DSM		Front Range Nixon CT Retire Renewable/Storage/DSM
Pathway D *Carbon Free*	11	80% Carbon by 2030 100% Carbon 2050		Drake 6 & 7 Retire Non-Carbon & DSM	Nixon 1 Retire Non-Carbon & DSM	Birdsall 1-3 Retire Non-Carbon & DSM		Front Range Nixon CT Retire Non-Carbon & DSM
Pathway E *Early Coal* *Decommission*	12	50% Carbon by 2023 80% Carbon by 2030 90% Carbon 2050	Drake 6 & 7 Retire Aeroderivative Gas	Nixon 1 Retire Gas/Renewable/Storage/DSM		Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	16	50% Carbon by 2023 80% Carbon by 2030 90% Carbon 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Gas/Renewable/Storage/DSM	Birdsall 1-3 Retire Gas/Renewable/Storage/DSM		
	17	50% Carbon by 2023 80% Carbon by 2030 90% Carbon 2050	Drake 6 & 7 Retire Aeroderivative Gas		Nixon 1 Retire Non-Carbon & DSM	Birdsall 1-3 Retire Non-Carbon & DSM		
Pathway F *100 %* *Renewable*	15	100% Renewable by 2030		Drake 6 & 7 Retire Renewable/Storage/DSM	Nixon 1,2,3 Retire Front Range Birdsall Renewable/Storage/DSM			
	18	100% Renewable by 2040				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM	Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM	
	19	100% Renewable by 2050				Drake 6 & 7 Retire Birdsall Renewable/Storage/DSM		Nixon 1,2,3 Retire Front Range Renewable/Storage/DSM

Top 5 Portfolios (on Attribute Scoring)

Portfolio	Pathway	CO2 Target	Retirements	New Resources	Attribute Ranking	Total Score Normalized
17	E	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	1	100
16	E	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	2	99
12	E	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2026	Aeroderivative/Gas/Renewable/Storage/DSM	3	98
10	C	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Renewable/Storage/DSM	4	98
11	D	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Non-Carbon/Storage/DSM	5	93

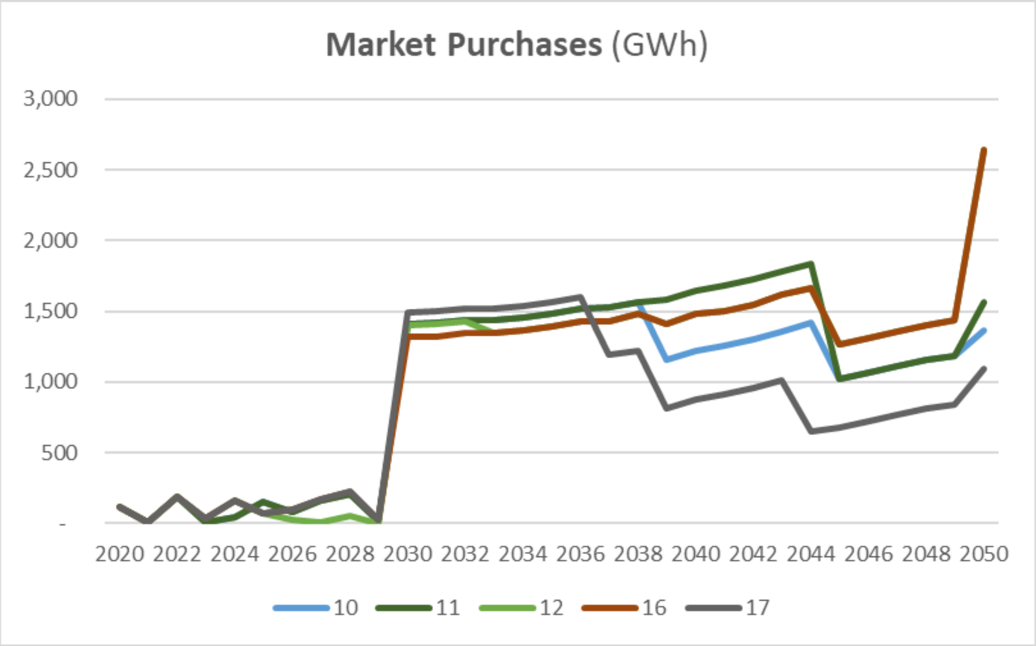
Note: These are the only 5 portfolios that scored above 90 on normalized scoring.

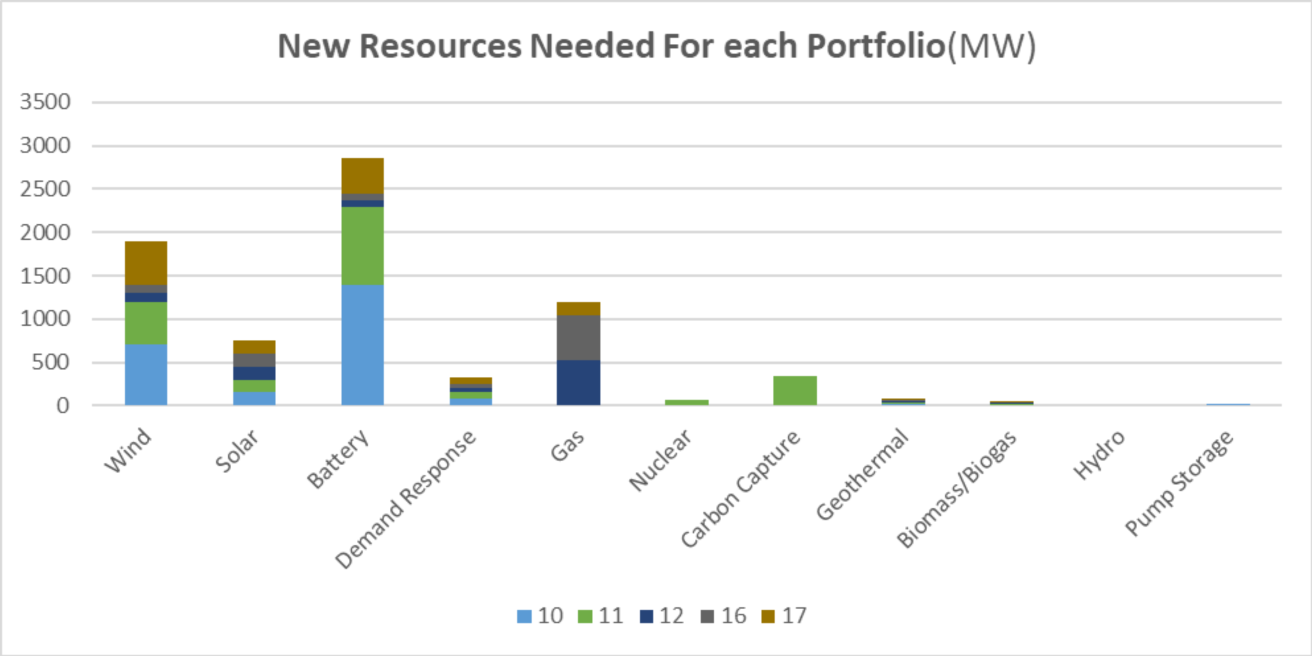
Financial Results of Top 5

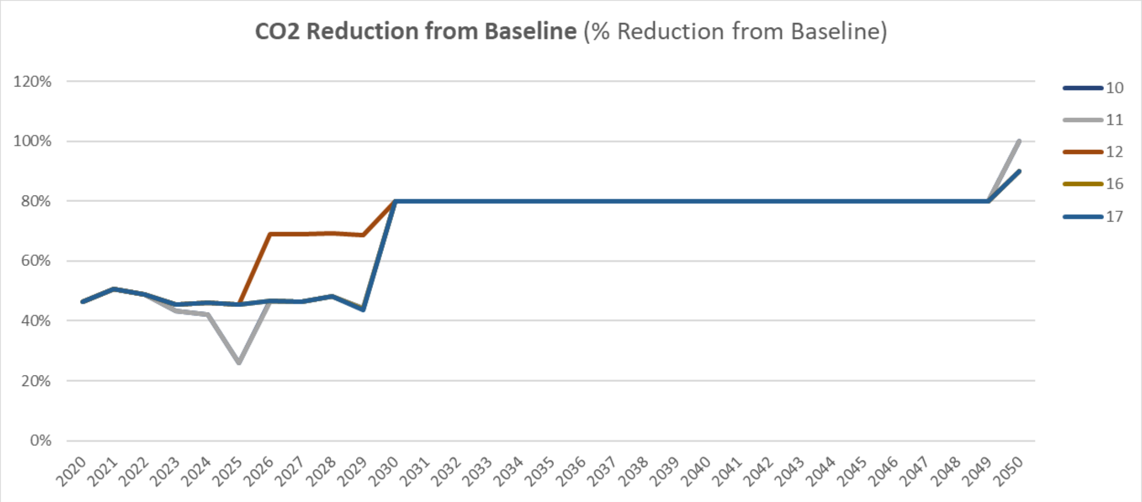
Top 5 Portfolio Sensitivity Results

Portfolio	CO2 Target	Retirements	New Resources	High Gas	Low Gas	No Energy Purchases	90x30	100x50	Drake 2022	High Load	Low Load	CO2 on Purchases	Low Renewable Cost
10	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Renewable/Storage/DSM	387	-511	514	162	N/A	N/A	333	-321	223	-174
11	80% by 2030 100% by 2050	Drake 2026 Nixon 1 2030 Front Range/Nixon 2,3 2050	Non-Carbon/Storage/DSM	484	-466	336	165	N/A	N/A	401	-374	170	-69
12	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2026	Aeroderivative/Gas/Renewable/Storage/DSM	579	-554	220	183	166	-14	277	-291	231	-8
16	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	535	-482	207	217	193	-13	308	-238	200	-1
17	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	458	-490	163	98	100	-55	330	-317	127	-96

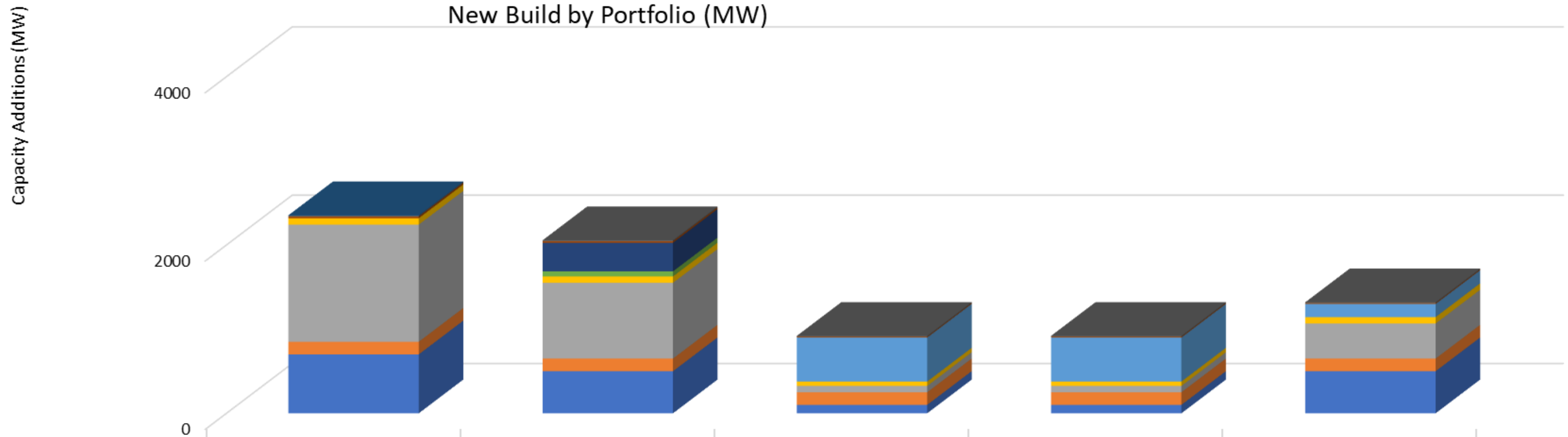
Top 5 Portfolio Market Purchases, New Resources and CO2 Reduction







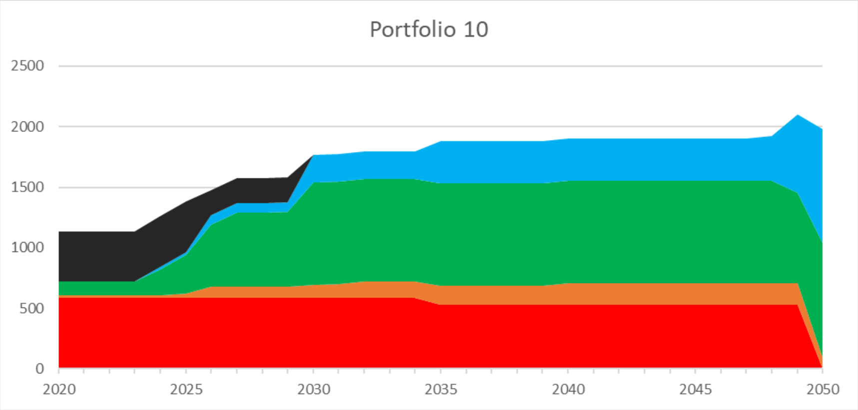
Top 5 Portfolio New Capacity Additions

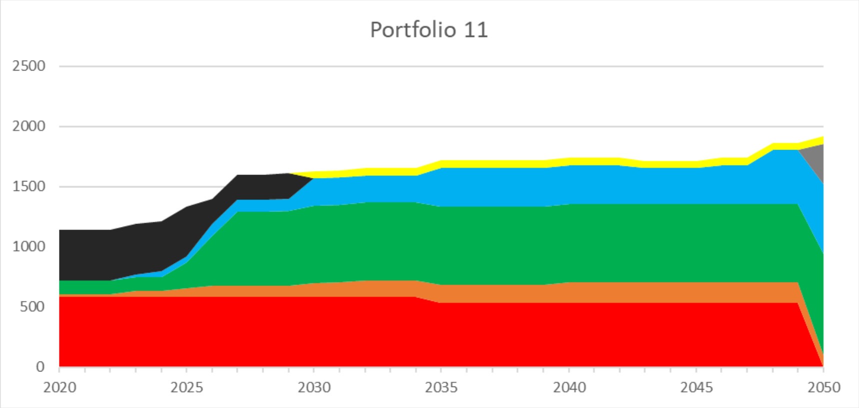


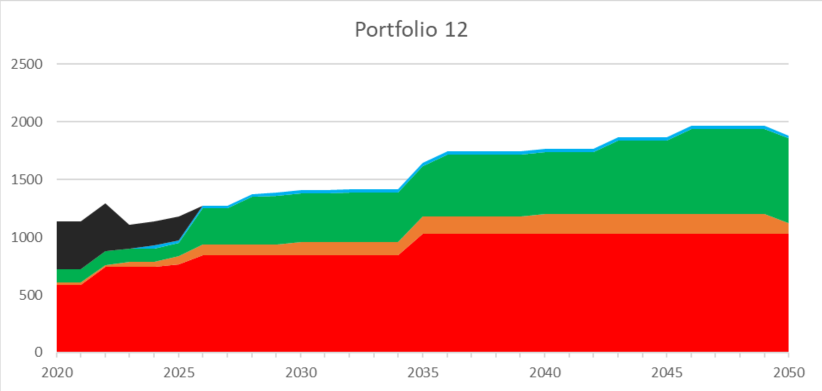
	10	11	12	16	17
Pump Storage	5				
Hydro					
Biomass/Biogas	10	10	10	10	10
Geothermal	20	20	10	10	10
Carbon Capture		340			
Nuclear		60			
Gas			523	523	156
Demand Response	76	76	52	52	76
Battery	1392	900	75	75	417
Solar	150	150	150	150	150
Wind	700	500	100	100	500

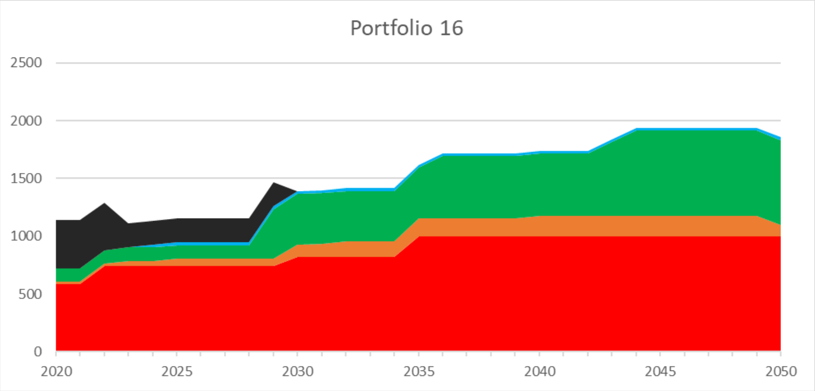
Top 5 Portfolio Capacity Mix

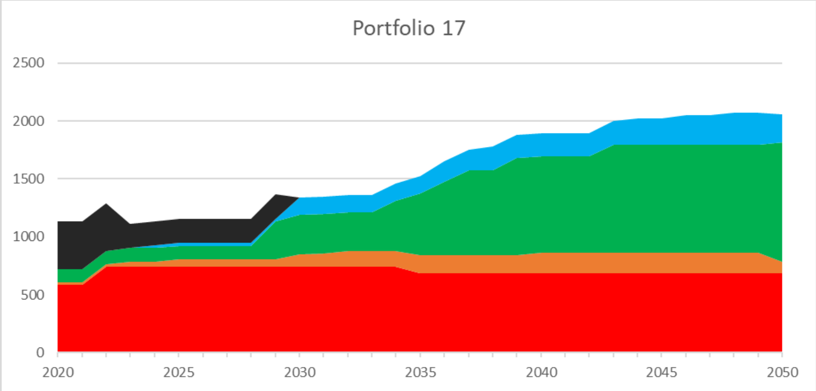
Gas DSM Renewable Battery Coal





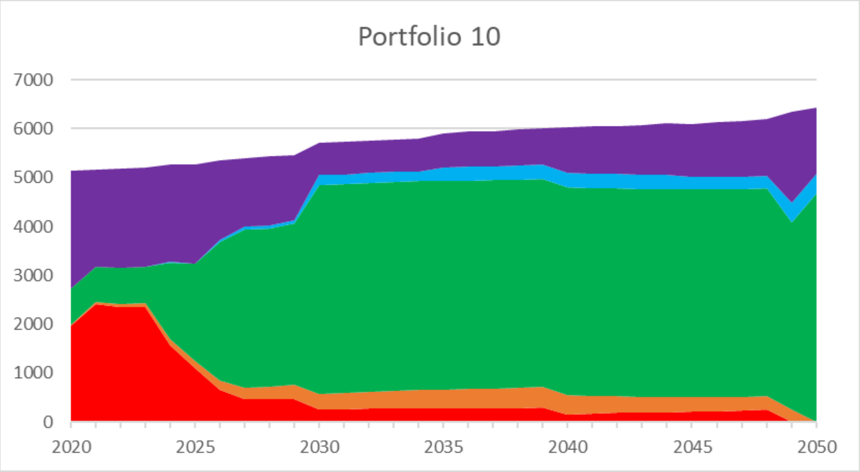


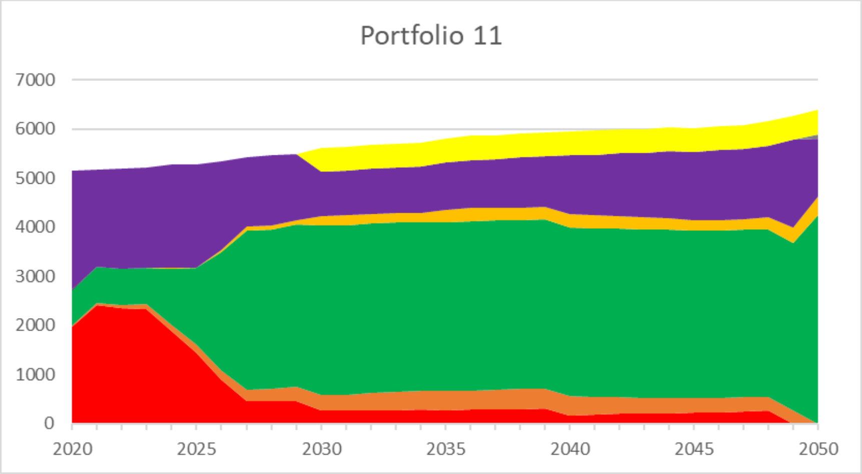


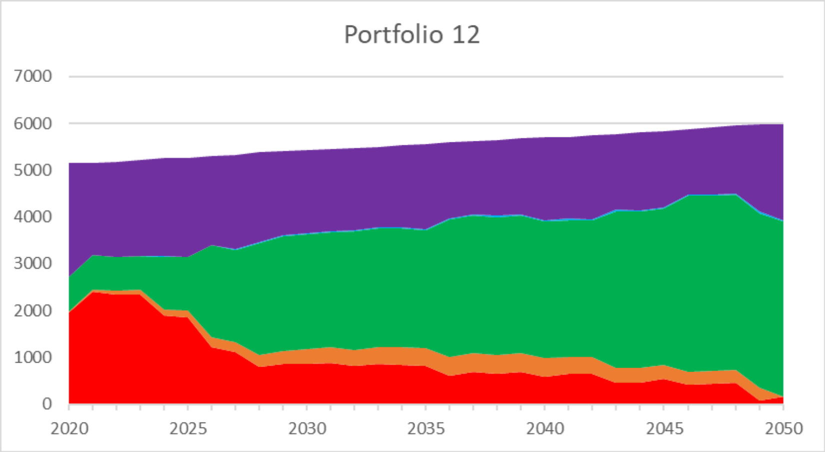


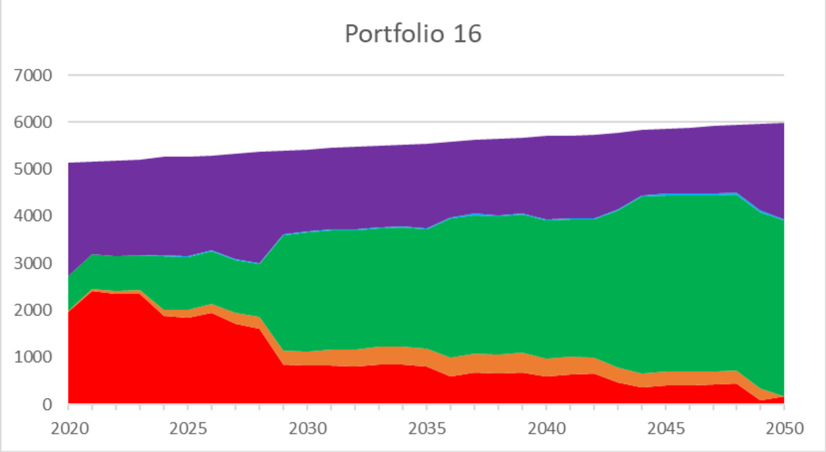
Top 5 Portfolio Energy Mix

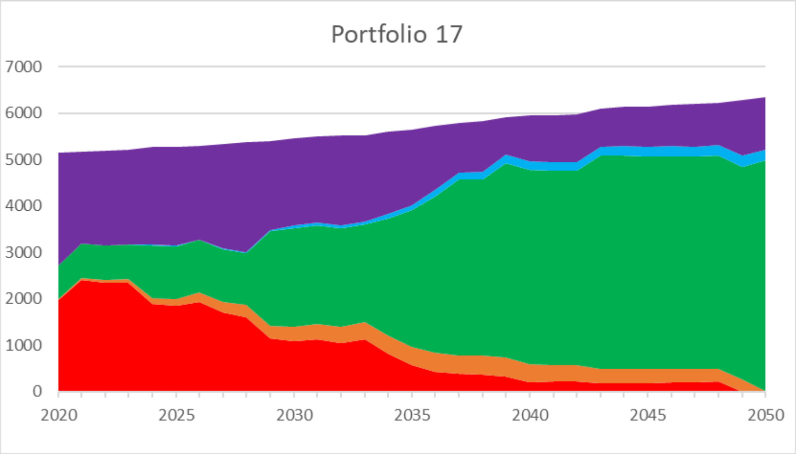
Gas DSM Renewable Battery Coal Purchase











Top 5 Portfolio Gas Capacity Expansion Plans

Workforce Impacts and Plan

Utilities Board Presentation

THANK YOU, UPAC!!!

UPAC next assignment

UPAC Next Assignment

- Potential assignment discussion
  - June 11 -- Strategic Planning Committee
  - June 17 – Utilities Board
- UPAC assignment draft scope
  - July 16 – Strategic Planning Committee
  - July 22 – Utilities Board approval
- Assignment to UPAC
  - August 5


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

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

Electric and Gas Integrated Resource Plans

Utilities Board Special Meeting for Approval

June 26, 2020

Agenda

- Welcome and Introduction
- Summary of UPAC Recommendations
- Portfolios 16 and 17 Comparison
- Customer Comment
- Board Discussion and Decision

Public Process Update

Public Engagement Summary

Public Comment Summary

Emails to energyvision@csu.org

- 38 received 5/29-6/15
- 37 received 6/15-6/17

Public Meetings Speakers

28 people spoke at the Utilities Board June 17 meeting

- 6 Stakeholder Groups
- 22 Citizens/Customers

Summary of UPAC Recommendations

EIRP Recommendation

Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 16	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Gas/renewable/ storage/DSM	Birdsall retire Gas/renewable/ Storage/DSM		
Gas	G-E16		LDC IT with oil backup		Expand/new pipeline capacity with NNT		Expand/new pipeline capacity with NNT			

Reasons for UPAC's recommendation of Portfolio 16:

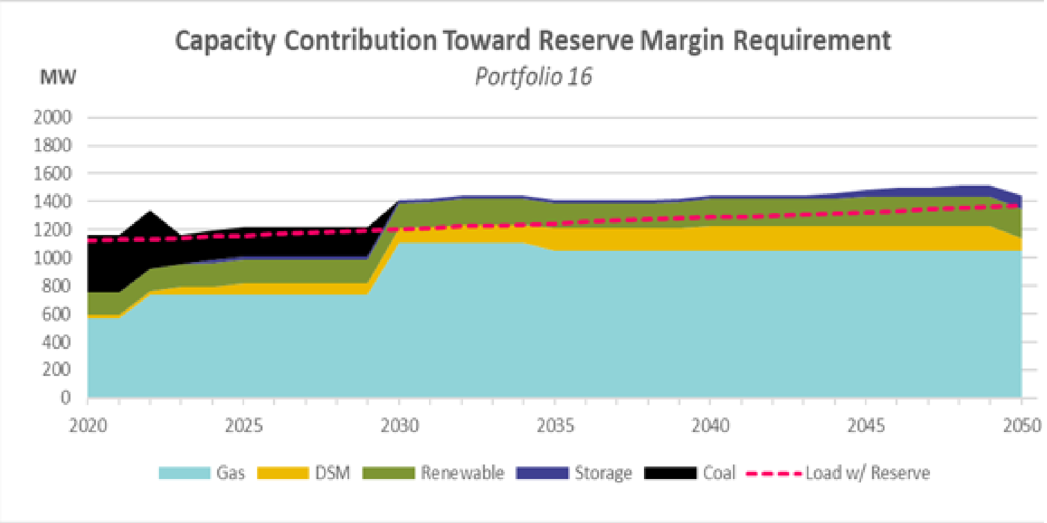
- High Attribute ranking
- Meets state regulatory carbon reduction
- Solid financial results
- Reasonable risk profile
- Uses proven innovative technology
- Earliest Drake decommissioning
- Provides flexibility on Nixon 1 replacement

EIRP PORTFOLIO 16

Overview

- Carbon reduction goals: 80% by 2030, 90% by 2050
- Coal retirement: Drake Power Plant no later than 2023, Nixon Power Plant no later than 2030
- Other retirement: Birdsall Power Plant no later than 2035
- Replacement: Small, mobile natural gas generators, renewable energy, storage and other natural gas generation plus energy efficiency initiatives

Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 16	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Gas/renewable/ storage/DSM	Birdsall retire Gas/renewable/ Storage/DSM		
Gas	G-E16		LDC IT with oil backup		Expand/new pipeline capacity with NNT		Expand/new pipeline capacity with NNT			



Resource Change 2021-2050 (MW)	
Drake (2023)	-208
Nixon 1 (2030)	-207
Nixon 2-3	0
Birdsall (2035)	-54
Front Range	0
New Gas	523
DSM	52
Storage	75
Solar	150
Wind	100
Hydro	0
Geothermal	10
Biomass/ Biogas	10
Carbon Capture	0
Nuclear	0

Financial Metrics	
30 Year Revenue Requirement	$36.27B
Average Annual Revenue Requirement	$1.21B
Average Adjusted Debt Service Coverage	2.09
Average Adjusted Days Cash on Hand	179
30 Year Electric Revenue	$18.0B

Attribute Score	
Reliability	93
Cost/ Implementation	63
Environment/ Stewardship	72
Flexibility/ Diversity	75
Innovation	50
Total score (normalized)	98.7

Sensitivities ($ incremental)	
Social Cost	$1.05B
High Load	$308M
Low Load	($238)M
High Gas	$535M
Low Gas	($482)M
90x30	$217M
100x50	$193M
Drake 2022	($13)M

Risks

- Tight on capacity with early Drake decommissioning
- Electrification will provide a challenge in serving increased load while reducing GHG emissions
- Future regulatory risk (ex. 100% renewables)
- Transmission import limitations for wind generation

2 Attribute rank

1 Financial rank

C

GIRP Recommendation

Portfolio	2022	2025	2030	2032	2034	2035	2040	2043	2050
G-6		DR + EE		Propane Air Expansion			Propane Air New		

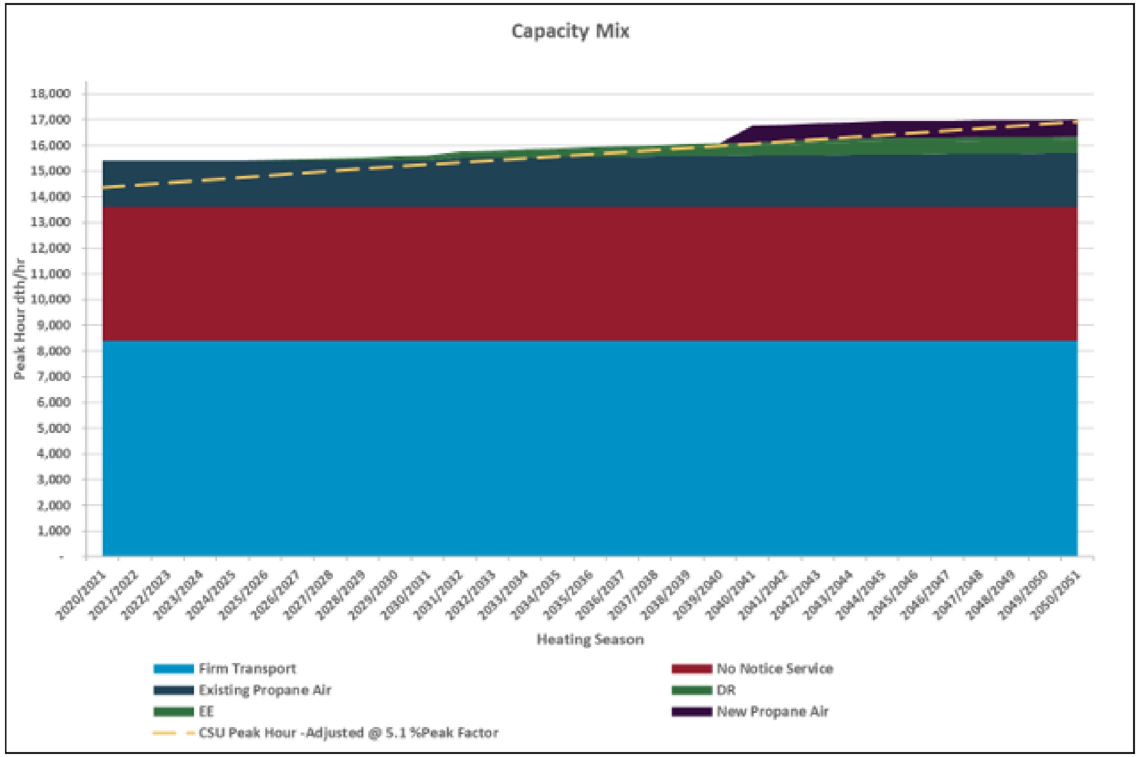
Reasons for UPAC's recommendation of Portfolio 6:

- Best attribute score
- Lowest revenue requirement
- Contains both DR and EE features
- Controllable risk profile
- Defers new infrastructure requirements

GIRP PORTFOLIO 6

Overview
Addition: Demand response, energy efficiency, new propane air, existing propane air expansion

	Portfolio	2022	2025	2030	2032	2034	2035	2040	2043	2050
Pathway C DSM + new peak shaving capacity	G-6		Demand response and energy efficiency		Propane air expansion			Propane air new		



Resource Change 2021-2050 (Dth/hr)	
Existing PA	300
New PA	650
New Pipeline Capacity	0
New LNG	0
Demand Response	500
Energy Efficiency	150

Financial Metrics	
30 Year Revenue Requirement	$35.71B
Average Annual Revenue Requirement	$1.190B
30 Year Gas Revenue	$5.73B

Attribute Score	
Reliability	83.5
Cost/ Implementation	100.0
Environment/ Stewardship	100.0
Flexibility/ Diversity	86.8
Innovation	72.7
Total score (normalized)	100.0

Sensitivities ($ incremental)	
High Growth	$7.79M
Low Growth	($12.54M)
Renewable Natural Gas (voluntary)	$64.10M
Non-firm Options	Included in EIRP Portfolios
Peaking Capacity Options	Requires Study
High DR	NA
High EE	NA
High DSM	($1.70M)
Distributed Generation on LDC System	Increases EIRP New Fixed Gas Costs by 86%

Risks

- High growth advances capital plan by 5 years, increases fixed gas costs
- Potential public push back on new PA Plant
- Electrification reduces load growth/revenue
- Regulatory risk mandating RNG
- Non-firm options require oil backup for DG
- DSM needs proof of concept, program development

1
Attribute rank

Portfolios 16 and 17 Comparison

Why Consider Portfolio 17

- Community input
- Board interest
- CEO/ Leadership/ Employee Recommendation

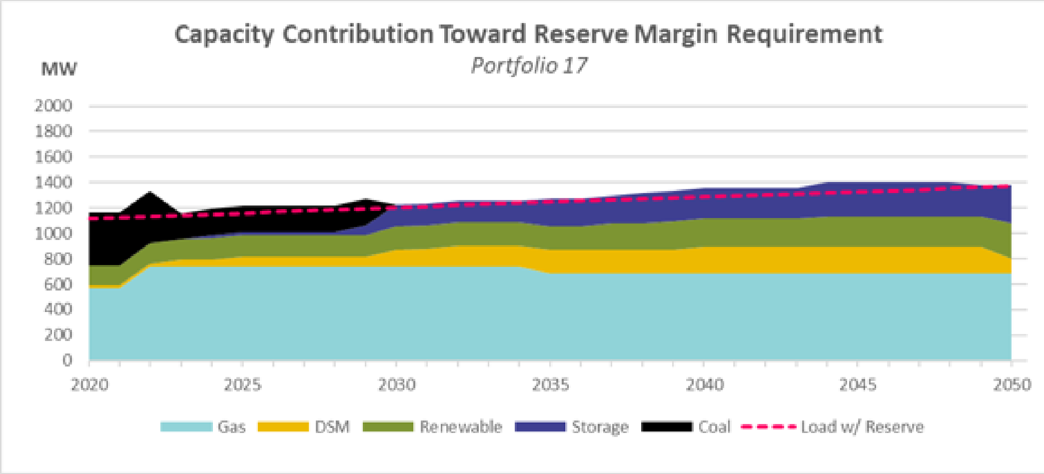
EIRP PORTFOLIO 17

Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 17	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Non-carbon, storage & DSM	Birdsall retire Non-carbon, storage & DSM		
Gas	G-E17		LDC IT with oil backup		Expand/new pipeline capacity with NNT					

EIRP PORTFOLIO 17

Overview
- Carbon reduction goals: 80% by 2030, 90% by 2050
- Coal retirement: Drake Power Plant no later than 2023, Nixon Power Plant no later than 2030
- Other retirement: Birdsall Power Plant no later than 2035
- Replacement: Small, mobile natural gas generators, non-carbon generation and storage plus energy efficiency initiatives

Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 17	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Non-carbon, storage & DSM	Birdsall retire Non-carbon, storage & DSM		
Gas	G-E17		LDC IT with oil backup		Expand/new pipeline capacity with NNT					



Attribute rank

Financial rank

Resource Change 2021-2050 (MW)	
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Nixon 1 (2030)	-207
Nixon 2-3	0
Birdsall (2035)	-54
Front Range	0
New Gas	156
DSM	76
Storage	417
Solar	150
Wind	500
Hydro	0
Geothermal	10
Biomass/ Biogas	10
Carbon Capture	0
Nuclear	0

Financial Metrics	
30 Year Revenue Requirement	$36.47B
Average Annual Revenue Requirement	$1.22B
Average Adjusted Debt Service Coverage	1.85
Average Adjusted Days Cash on Hand	154
30 Year Electric Revenue	$18.21B

Attribute Score	
Reliability	100
Cost/ Implementation	46
Environment/ Stewardship	69
Flexibility/ Diversity	88
Innovation	70
Total score (normalized)	100

Sensitivities ($ incremental)	
Social Cost	$0.97B
High Load	$330M
Low Load	($317)M
High Gas	$458M
Low Gas	($491)M
90x30	$98M
100x50	$100M
Drake 2022	($55)M

Risks
- Tight on capacity with early Drake decommissioning
- Electrification will provide a challenge in serving increased load while reducing GHG emissions
- Future regulatory risk (ex. 100% renewables)
- Transmission import limitations for wind generation

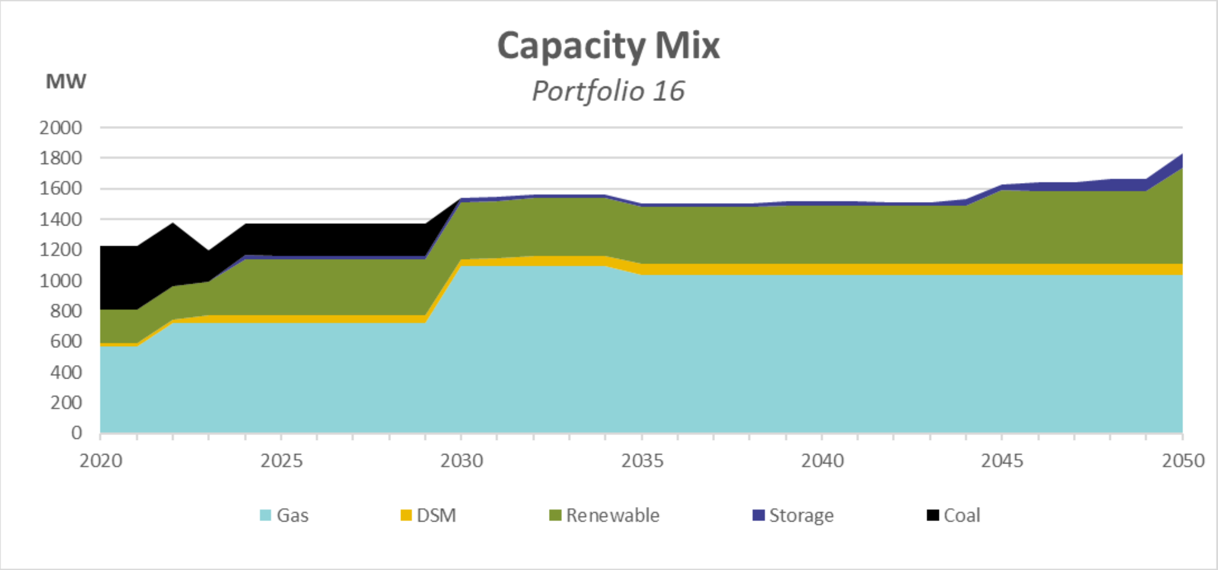
EIRP PORTFOLIO 16

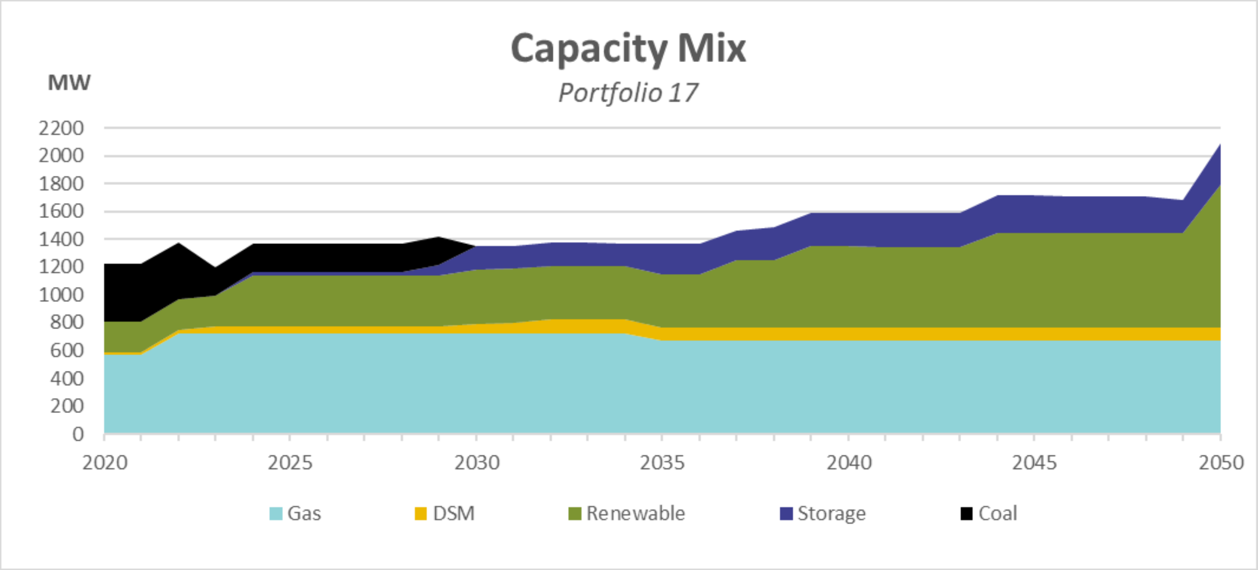
Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 16	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Gas/renewable/ storage/DSM	Birdsall retire Gas/renewable/ Storage/DSM		
Gas	G-E16		LDC IT with oil backup		Expand/new pipeline capacity with NNT		Expand/new pipeline capacity with NNT			

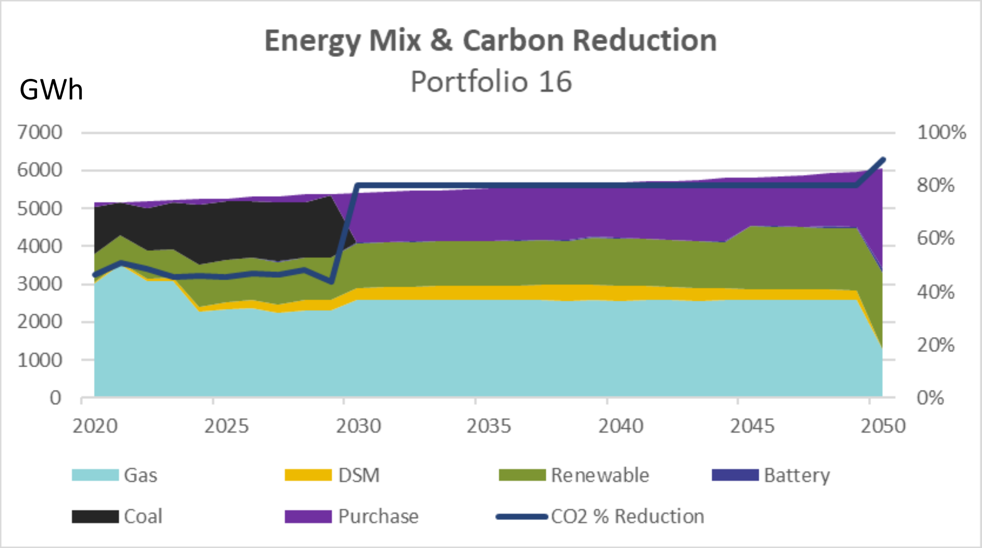
EIRP PORTFOLIO 17

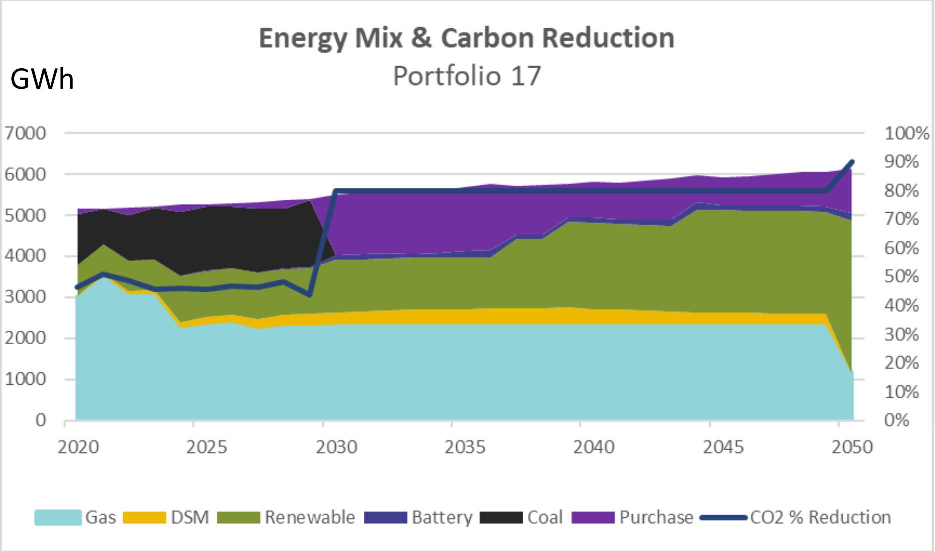
Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 17	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Non-carbon, storage & DSM	Birdsall retire Non-carbon, storage & DSM		
Gas	G-E17		LDC IT with oil backup		Expand/new pipeline capacity with NNT					

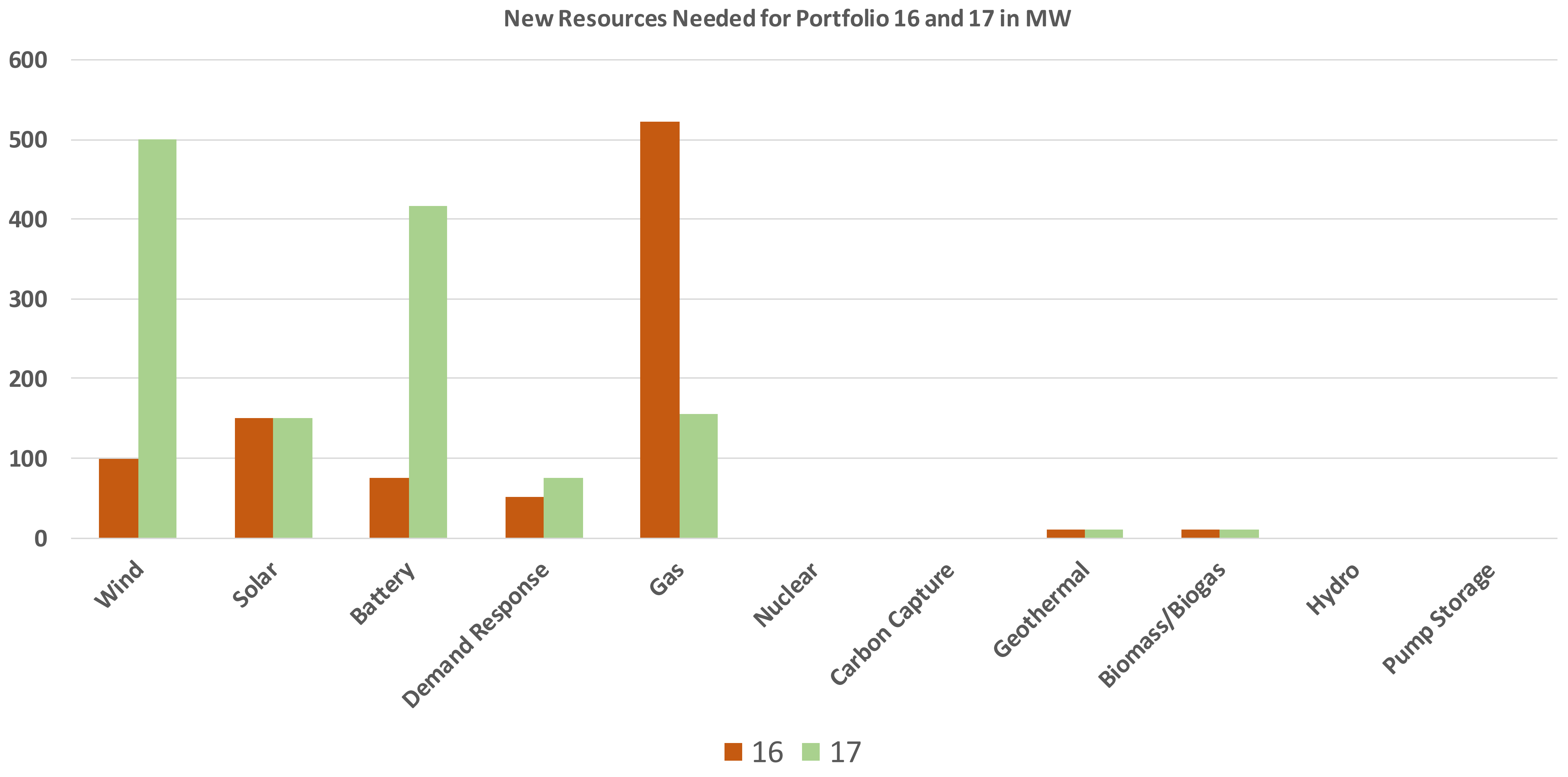
Portfolios 16 and 17 Capacity and Energy










New Resources Needed for Portfolio 16 and 17 in MW
600
500
400
300
200
100
0
Wind
Solar
Battery
Demand Response
Gas
Nuclear
Carbon Capture
Geothermal
Biomass/Biogas
Hydro
Pump Storage
16
17

IRP Goals (Phase 1)

Resilient and reliable

- Industry leading reliability and resiliency while avoiding potential stranded assets
- Support economic growth of the region

Cost-effective energy

- Maintain competitive and affordable rates
- Further advance energy efficiency and demand response

Environmentally sustainable

- Grow renewable portfolio
- Establish timelines for decommissioning of assets

Reduces our carbon footprint

- Meet all environmental regulations with specific metrics that include reducing our carbon footprint
- Reduce reliance on fossil fuels

Uses proven state-of-the-art technologies

- Proactively and responsibly integrate new technologies

to enhance our quality of life for generations to come

Attribute Scoring (Phase 2)

	Reliability	Cost / Implementation	Environment / Stewardship	Flexibility / Diversity	Innovation	Total
Weighting	32%	22%	22%	14%	10%	
Criteria	1. Quick Ramp 2. Quick Start 3. Market Purchases 4. Availability	1. NPVRR 2. Decommission timeframe	1. GHG Reduction 2. Land Use 3. Water Use	1. Average Capacity 2. Generation Sources	1. Demand Reduction 2. State of the Art Technology use	
Portfolio 16 - Score	1.12	0.66	0.70	0.42	0.25	**3.15**
Portfolio 17 - Score	1.20	0.49	0.66	0.49	0.35	**3.19**

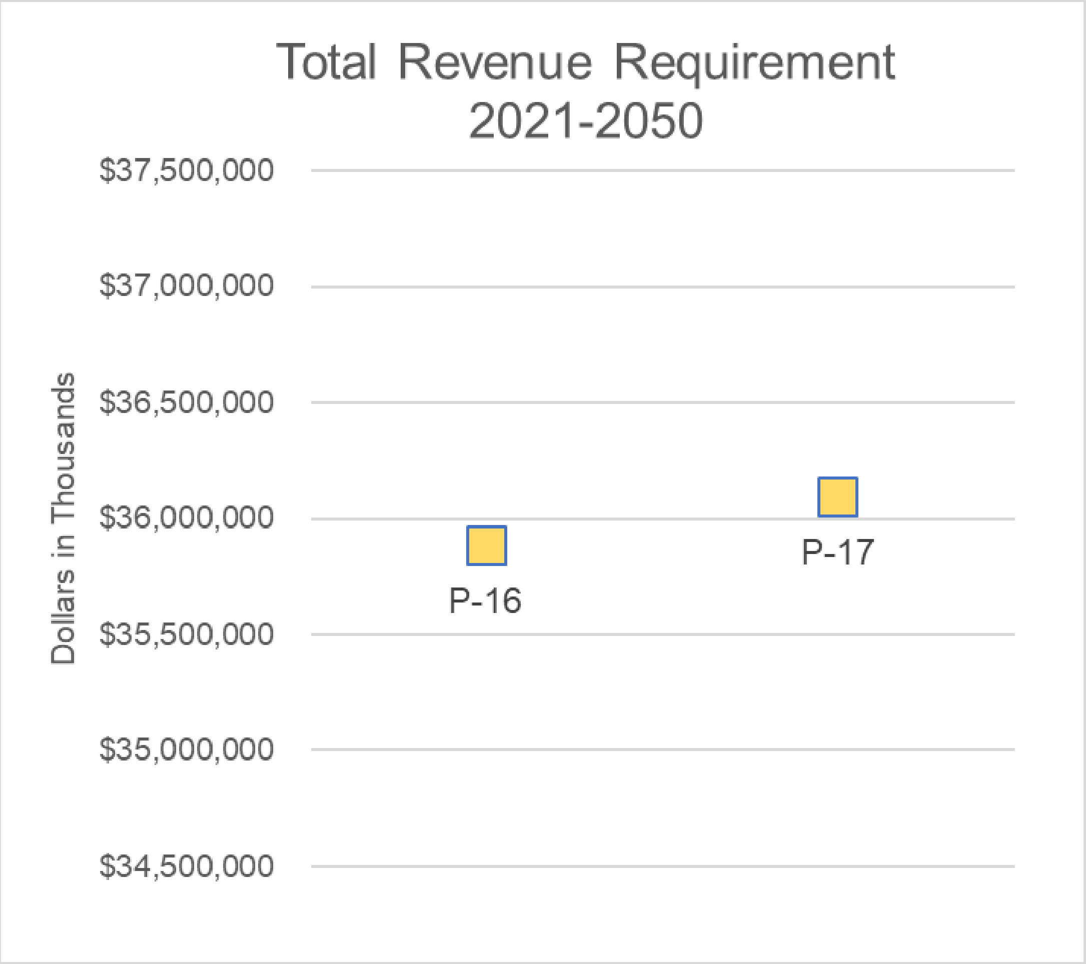
Note: Final Score is normalized against score of all other portfolios on 100 point scale.

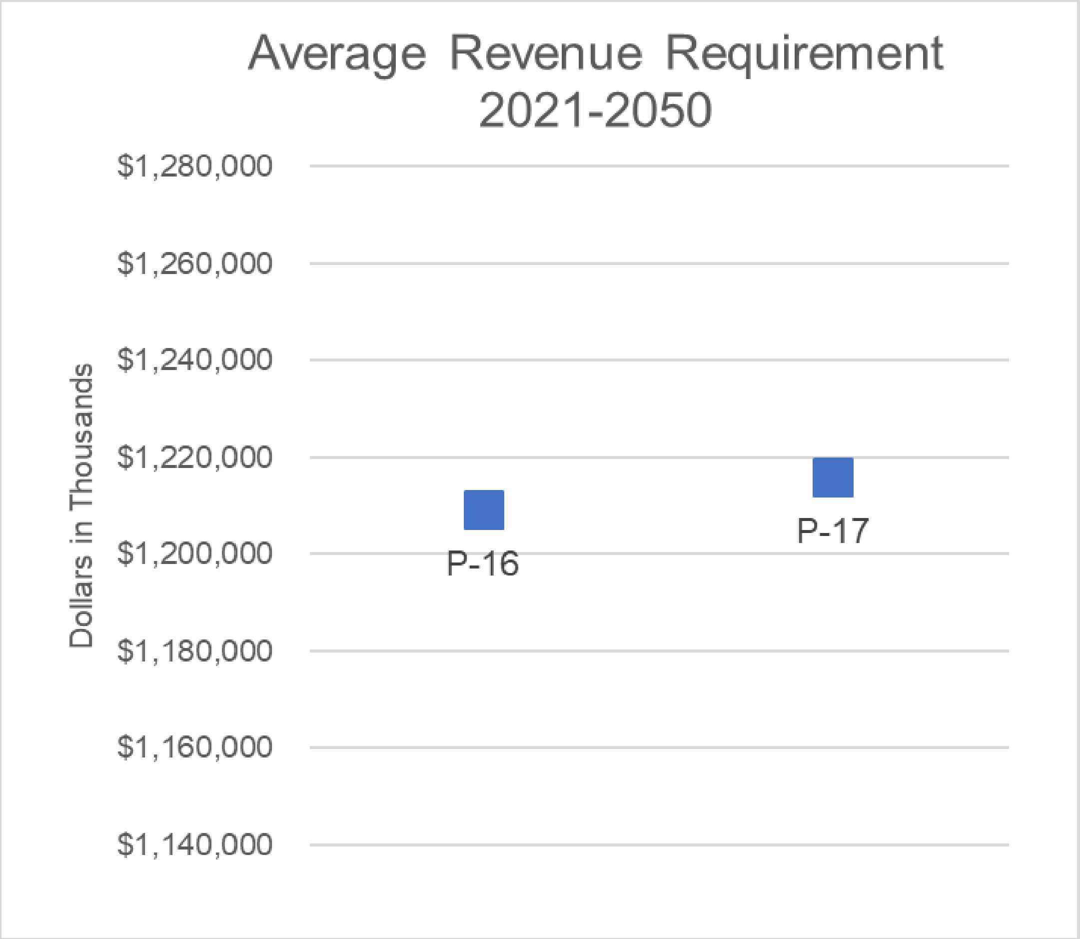
Portfolio 16 and 17 Scoring Slide

Portfolio	Pathway	CO2 Target	Retirements	New Resources	Attribute Ranking	Total Score Normalized	Financial Ranking	Total RR	% Increase to Portfolio R	% Increase to Portfolio 1
17	E	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Non-Carbon/Storage/DSM	1	100	4	$36.47B	2.10%	-0.21%
16	E	80% by 2030 90% by 2050	Drake 2023 Nixon 1 2030	Aeroderivative/Gas/Renewable/Storage/DSM	2	98.7	1	$36.27B	1.53%	-0.76%

Note: Total RR is total revenue requirement for all 4 services for 30 years in billions of dollars. It represents total cost to run Colorado Springs Utilities.

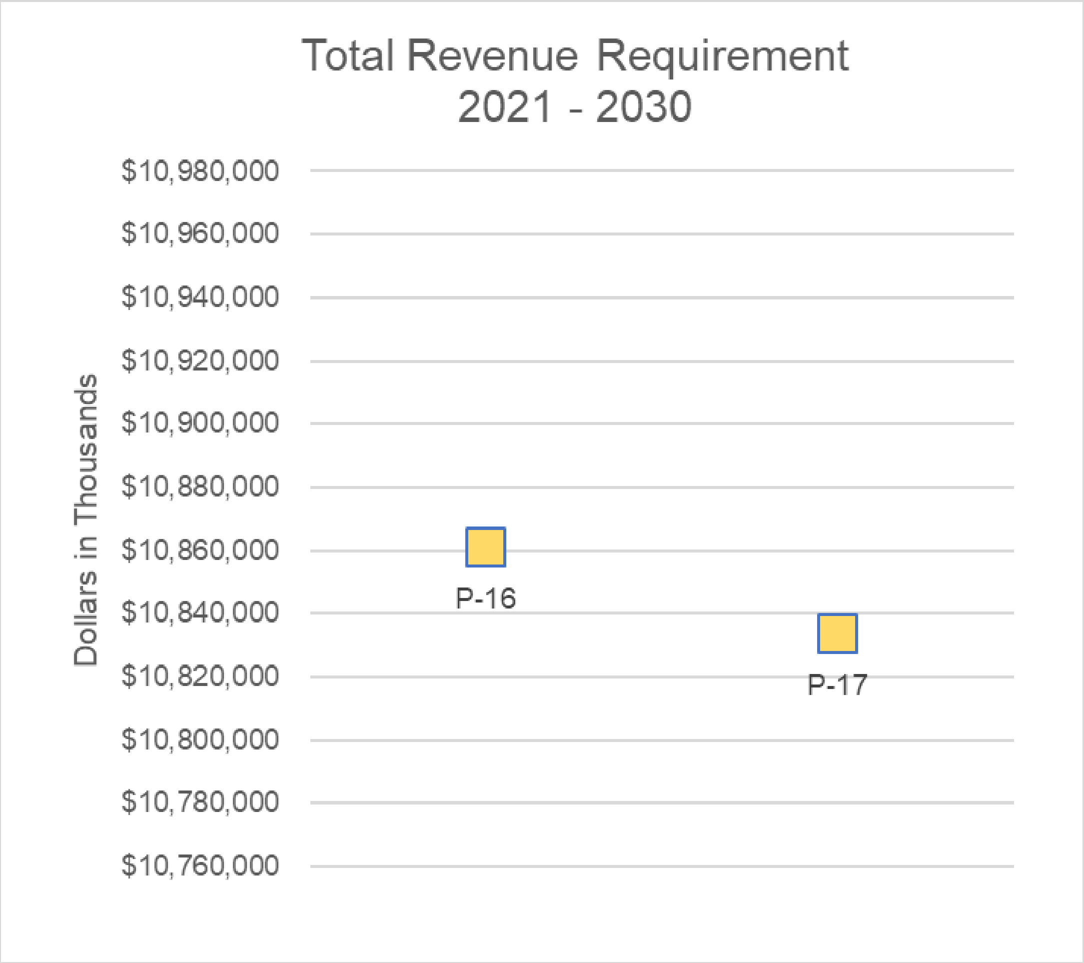
Portfolio 16 & 17 Financial Results (30 year)

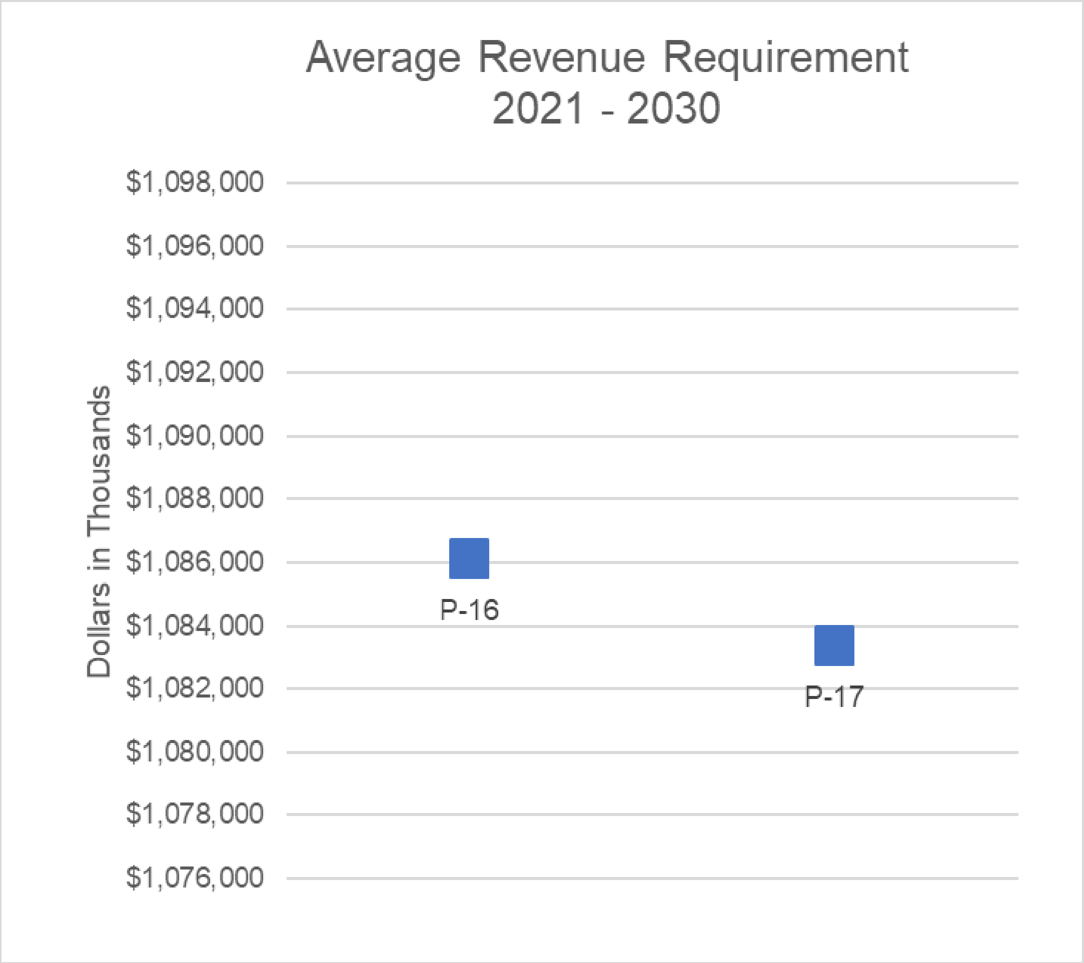




Revenue numbers are for 30 years.

Portfolio 16 & 17 Financial Results (10 year)





Revenue numbers are for 10 years.

Summary Comparison - Similarities

Portfolio 16:

- 2nd highest Attribute ranking (Phase 2)
- Meets state regulatory carbon reduction
- Solid financial results (within margin of error)
- Reasonable risk profile
- Earliest Drake decommissioning (NLT 2023) with gas aeroderivative replacement
- Provides flexibility on Nixon 1 replacement
- Aligned with community input (early decommissioning)
- Aligned with IRP Goals
- Aligned with GIRP Portfolio 6

Portfolio 17:

- Highest scoring portfolio on attributes (Phase 2)
- Meets state regulatory carbon reduction
- Solid financial results (within margin of error)
- Reasonable risk profile
- Earliest Drake decommissioning (NLT 2023) with gas aeroderivative replacement
- Provides flexibility on Nixon 1 replacement
- Aligned with community input (early decommissioning)
- Aligned with IRP Goals
- Aligned with GIRP Portfolio 6

Summary Comparison - Differences

Portfolio 16:

- Relies on gas resources and demand side management to replace Nixon 1 capacity

Portfolio 17:

- Relies on wind, energy storage and demand side management to replace Nixon 1 capacity
- Less dependence on spot market purchases to serve load and reduce carbon footprint

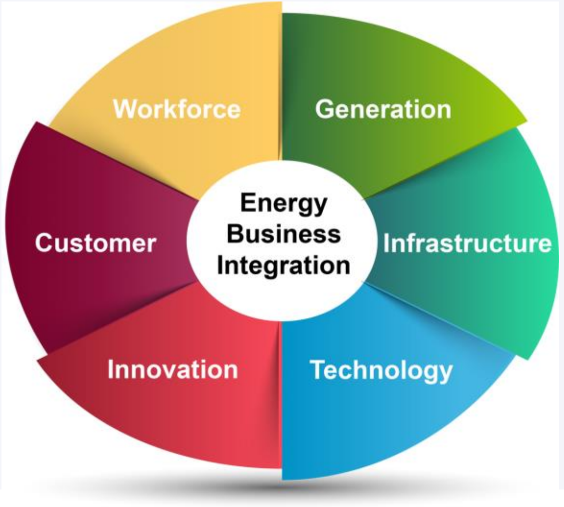
Utilities' Recommendation- Portfolio 17

EIRP PORTFOLIO 17

Pathway	Portfolio	Carbon targets	2022	2023	2025	2026	2030	2035	2040	2050
Pathway E	Portfolio 17	2030 80% 2050 90%		Drake retire Small, mobile, natural gas generator			Nixon 1 retire Non-carbon, storage & DSM	Birdsall retire Non-carbon, storage & DSM		
Gas	G-E17		LDC IT with oil backup		Expand/new pipeline capacity with NNT					

Reasons for Utilities' recommendation of Portfolio 17:

- Enhanced reliability and resilience
- Investment in infrastructure to support renewables and advanced technologies
- Supports vision of advancing renewable energy and future technologies (e.g. microgrids, storage, electric vehicles, AMI, distributed resources, etc.)
- Will promote innovation, utility transformation and agility
- Use gas resources for Nixon replacement only as a contingency/back up plan



Colorado Springs Utilities

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Customer Comment

Colorado Springs Utilities

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Board Discussion and Decision


Colorado Springs Utilities
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Supplemental Information

Public Comment Summary – June 17

Ft. Carson and Army Office of Energy Initiatives

- Resiliency is the most important aspect of their energy service.
- Colorado Springs Utilities has involved them in the IRP process and provides resilient power at Fort Carson.
- Army installations must have access to energy to assure readiness.
- Energy infrastructure is a key facet of resilience importance and the Army is willing to partner with Colorado Springs Utilities in siting key energy infrastructure that establish longer duration and larger scale backup resources.

Sierra Club Beyond Coal

- Applauds early coal retirement and the promise that no Utilities employees will lose their job.
- Sees the need to invest in new energy sources, but prefers renewable resources to fossil fuel due to environmental impacts.
- New natural gas plants will cost more money with significant regulatory risk.
- Supports Portfolio 17.

Public Comment Summary – June 17

Penrose/St. Francis

- Penrose/St. Francis partners with Colorado Springs Utilities at both campuses.
- They rely on resilience and enhanced power at St. Francis, and look forward to planning programs with Interquest campus, and the possibility of a solar farm there.
- Appreciative of rebate programs.

Downtown Partnership

- Downtown Partnership were engaged and participated in the IRP, and appreciates strong business community involvement.
- Pleased with both portfolios and supporting portfolio 17, as it gives an edge with wind and battery for a clean energy future, new investment to downtown, and opportunity to have a bold clean energy commitment.
- Supports swift plan for decommissioning Drake Power Plant, which will attract businesses looking for this commitment.

Public Comment Summary – June 17

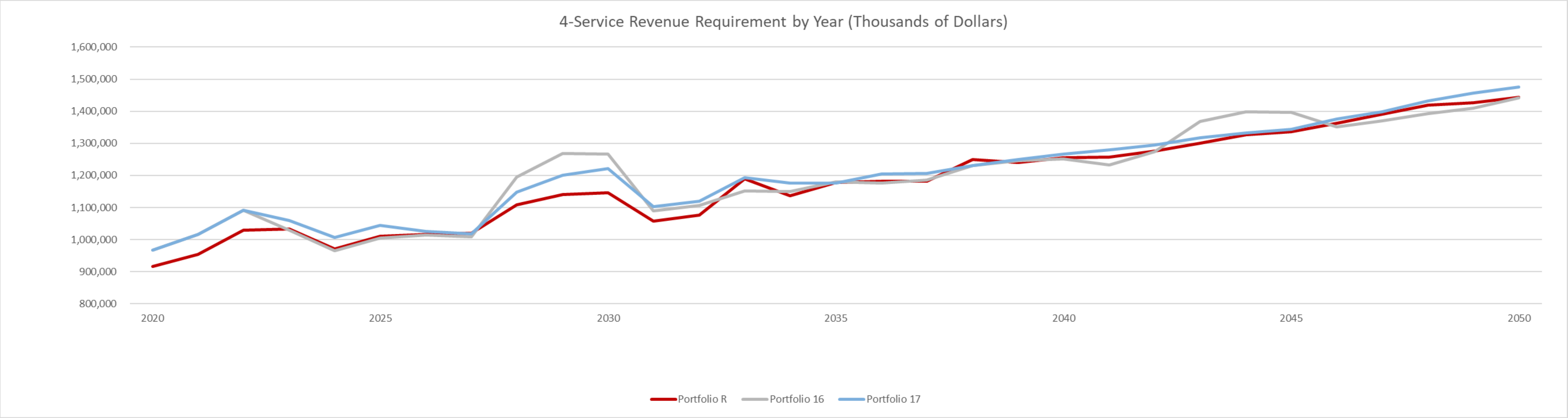
Chamber of Commerce & EDC

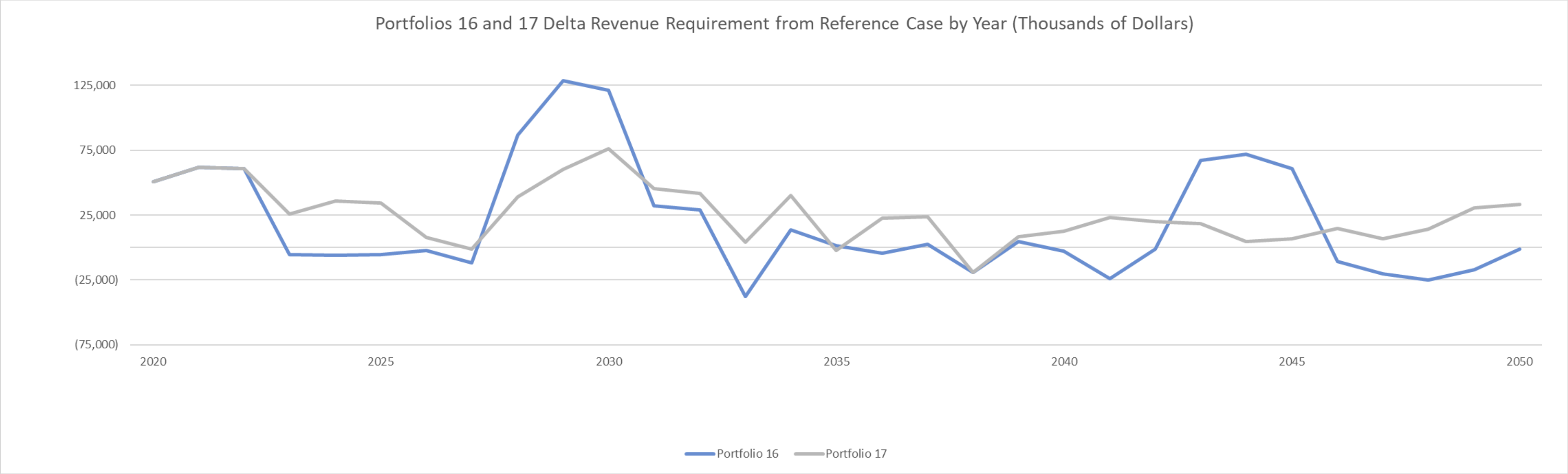
- Agrees with the five attributes used to evaluate portfolios.
- The Chamber & EDC has participated, and presented to UPAC, appreciate adjustments made, and endorsed the process conducted with robust public outreach.
- Sees Drake redevelopment and future of the plant as a gateway and opportunity for revitalization downtown.

Public Comments

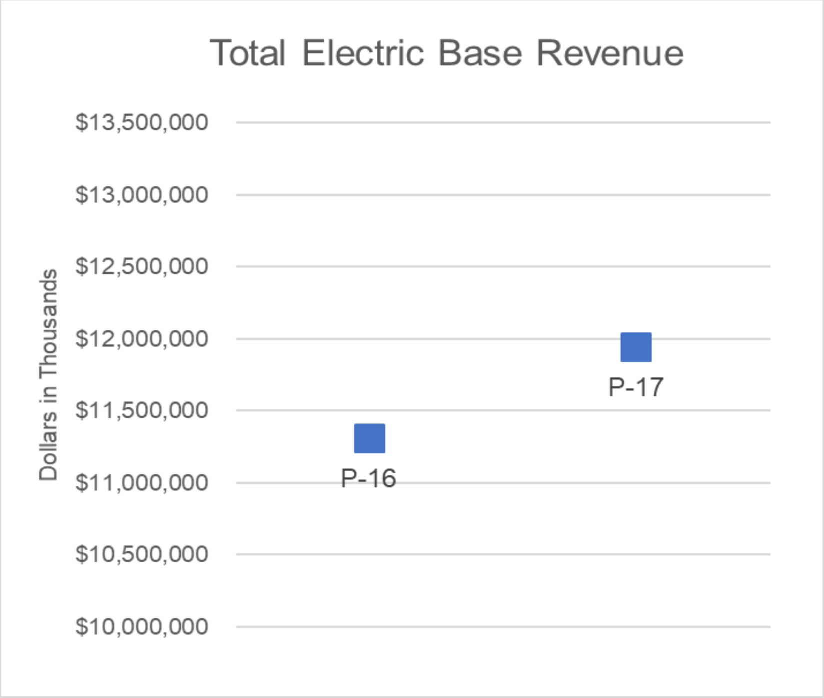
- Nineteen Speakers supported Portfolio 17 over Portfolio 16.
- Two speakers supported Portfolio 10, one speaker supported Portfolio 16.
- Preference for renewable resources vs. fossil fuels as replacement for Drake and Nixon.

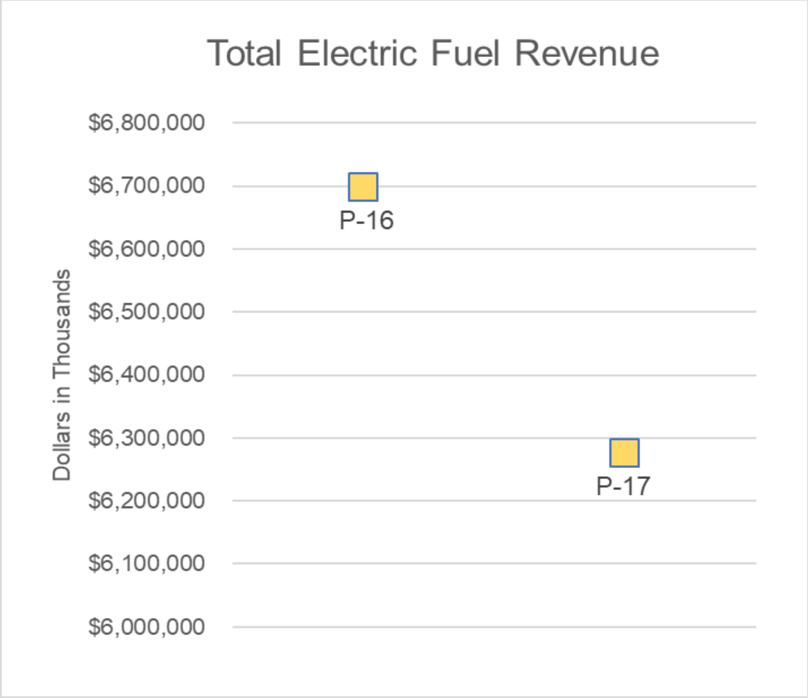
Revenue Requirement Comparison

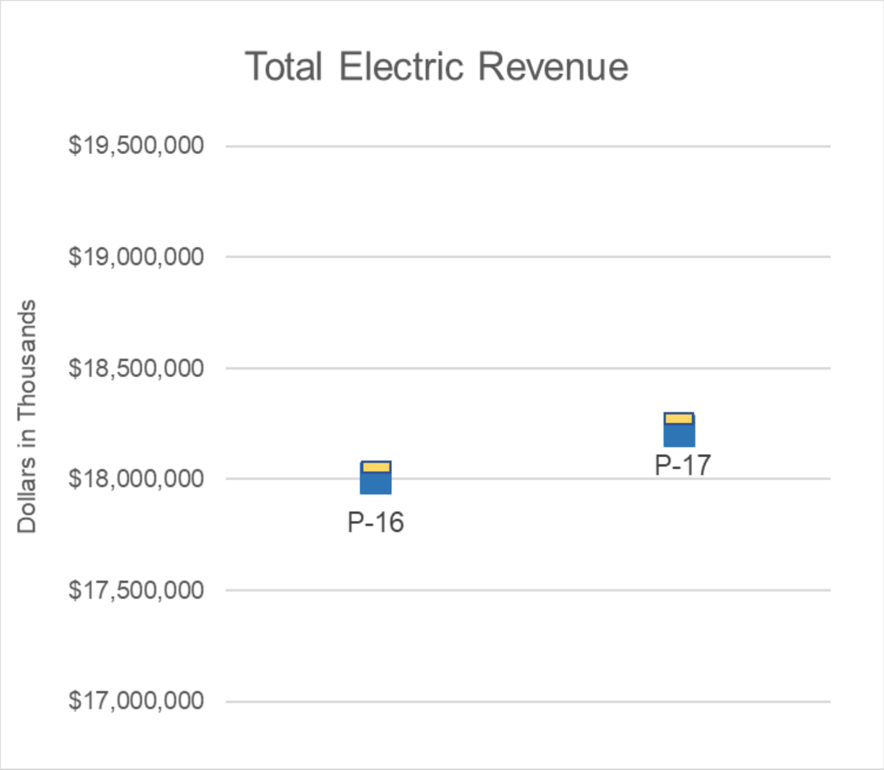




Electric Revenue – Base and Fuel





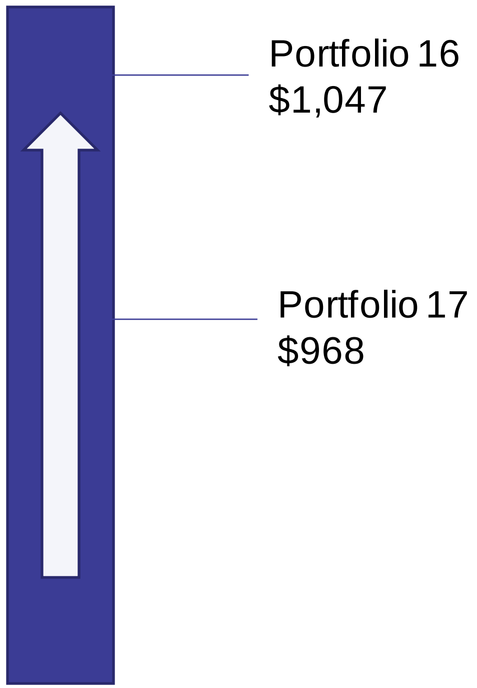


Revenue numbers are for 30 years.

EIRP Sensitivity
Social Cost of Carbon

- All portfolios are more costly
- Accelerates CO_2 reduction by backing down coal and gas generation
- Requires substantial increase in carbon free or renewable energy
- Gas resources built to meet capacity requirements but do not run much

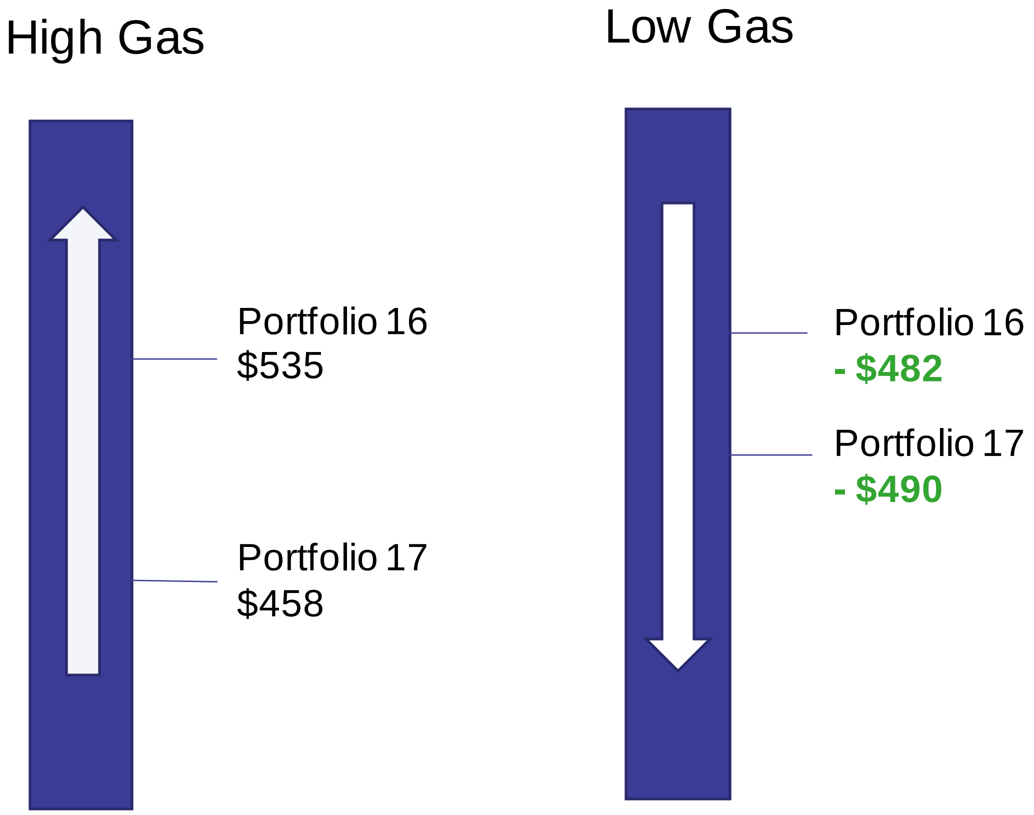
Social Cost of Carbon



Incremental net present value revenue requirement over 30 years.
Numbers are in millions of dollars.
Black numbers indicate increase.

EIRP Sensitivity
Gas Price

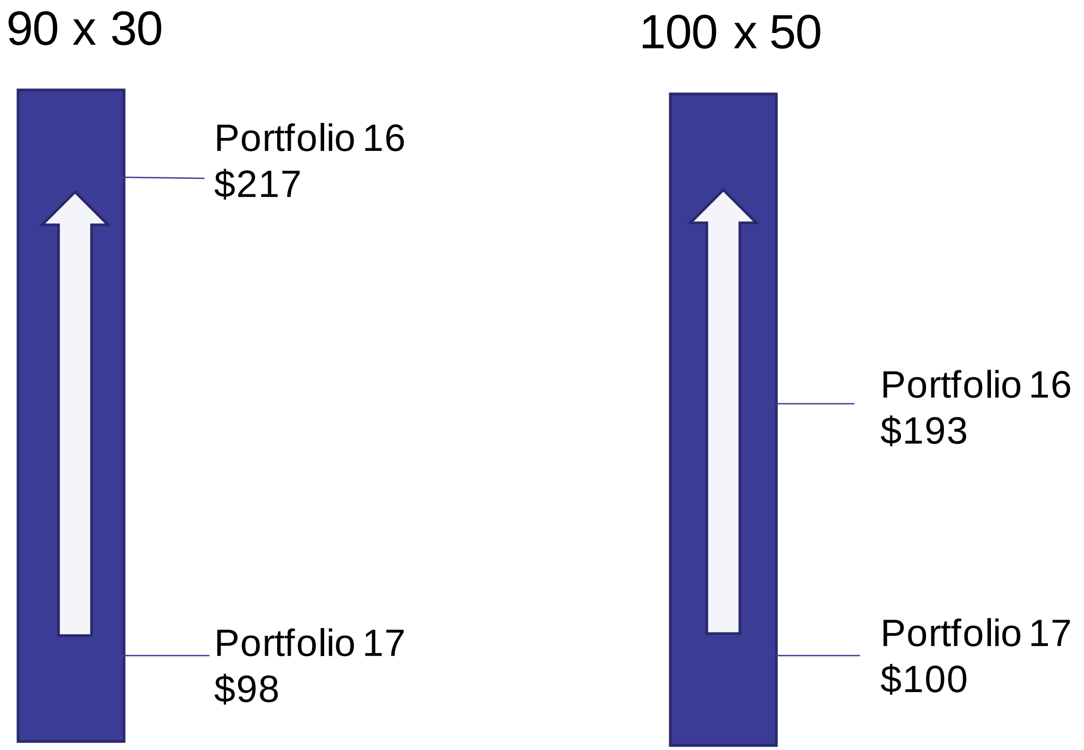
- Both gas and renewable portfolios are impacted due to cost of market purchases
- Low gas prices help all portfolios
- High gas prices hurt all portfolios



Incremental net present value revenue requirement over 30 years. Numbers are in millions of dollars. Green numbers indicate decrease in revenue requirement. Black numbers indicate increase.

EIRP Sensitivity
Carbon reduction

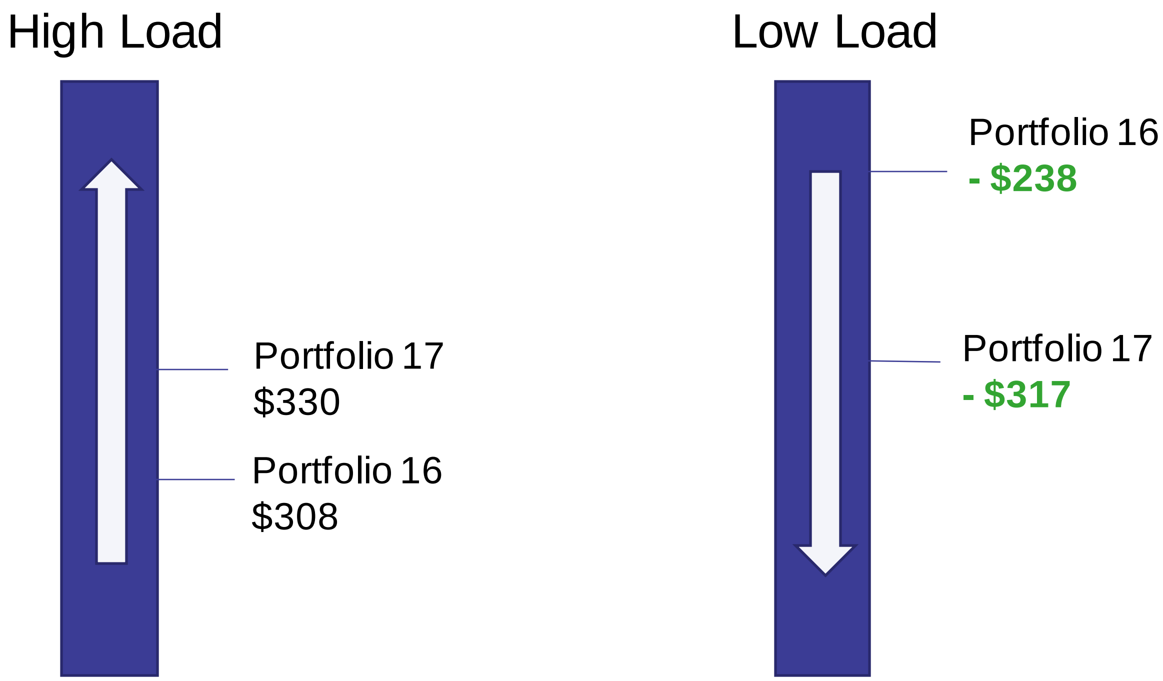
- All portfolios are more costly
- Increased reliance on energy market
- Model still builds gas generation as bridge allowing for cost of renewables to continue to decline
- Current transmission infrastructure not sufficient to achieve 100% renewable energy
- A lot of excess energy and hours of curtailment, and a significant amount of energy storage and DSM needed
- Portfolios 10 and 11 already meet 100% by 2050 target



Incremental net present value revenue requirement over 30 years. Numbers are in millions of dollars. Black numbers indicate increase.

EIRP Sensitivity
Load Forecast

- High load represents potential annexation and electrification scenarios
- Electrification will increase electric revenue requirement but decrease gas revenue requirement
- High load increases total revenue requirement
- Low load decreases total revenue requirement



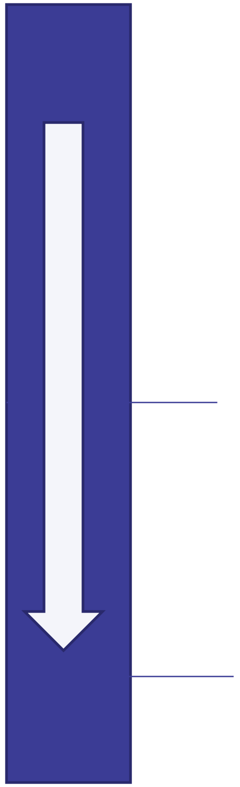
Incremental net present value revenue requirement over 30 years. Numbers are in millions of dollars. Green numbers indicate decrease in revenue requirement. Black numbers indicate increase.

EIRP Sensitivity

Drake retired no later than 2022

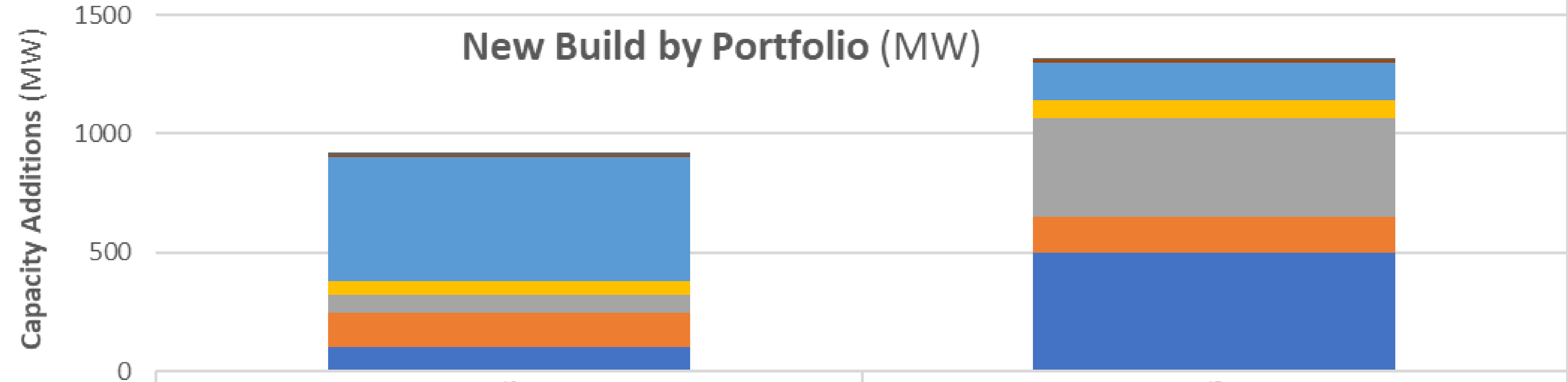
- Only possible in portfolios 12, 16 and 17
- Additional capacity is needed sooner
- Can lower costs even more depending on new capacity resource

Drake 2022



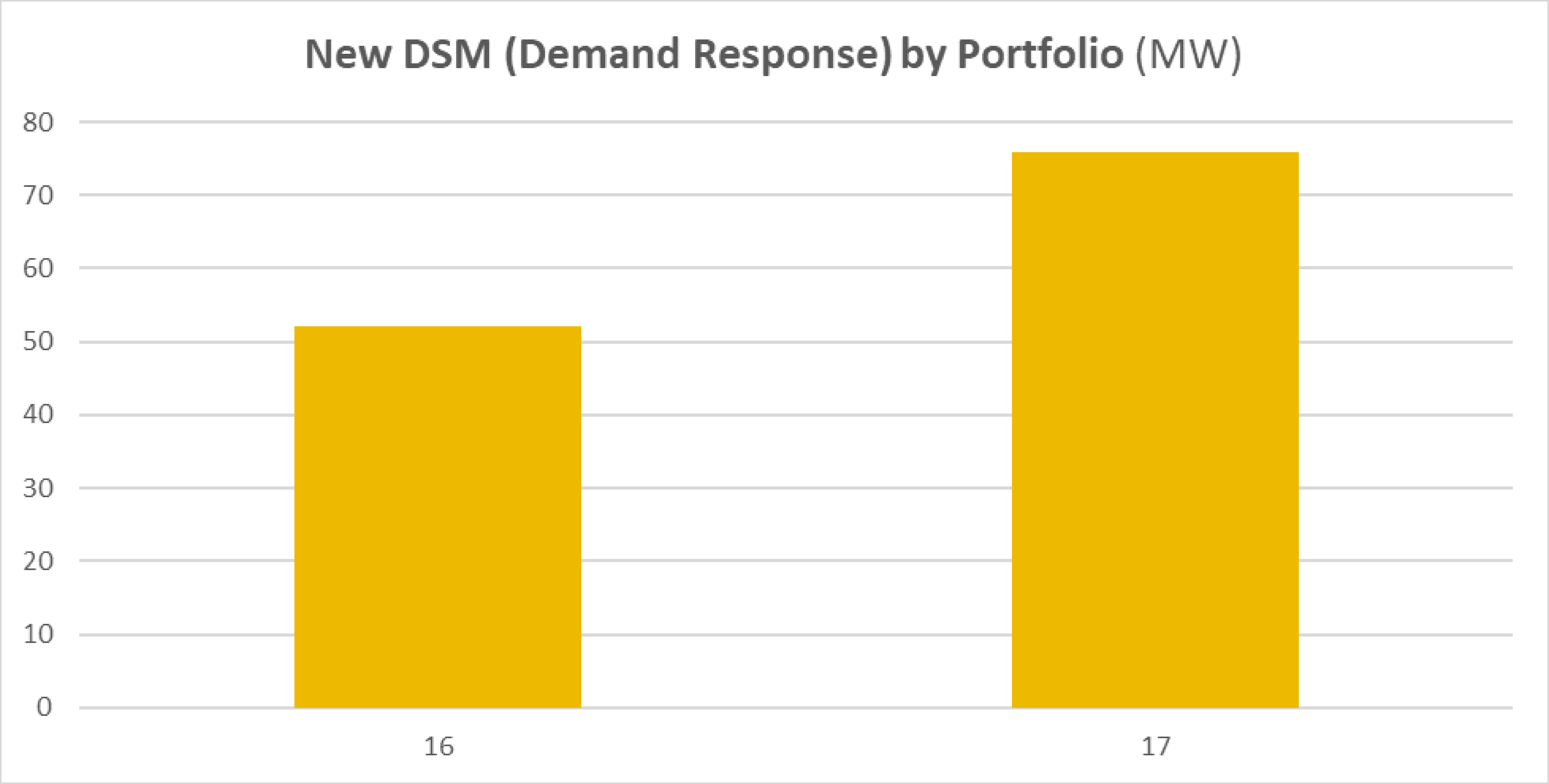
Incremental net present value revenue requirement over 30 years. Numbers are in millions of dollars. Green numbers indicate decrease in revenue requirement. Black numbers indicate increase.

Portfolios 16 and 17 New Resources

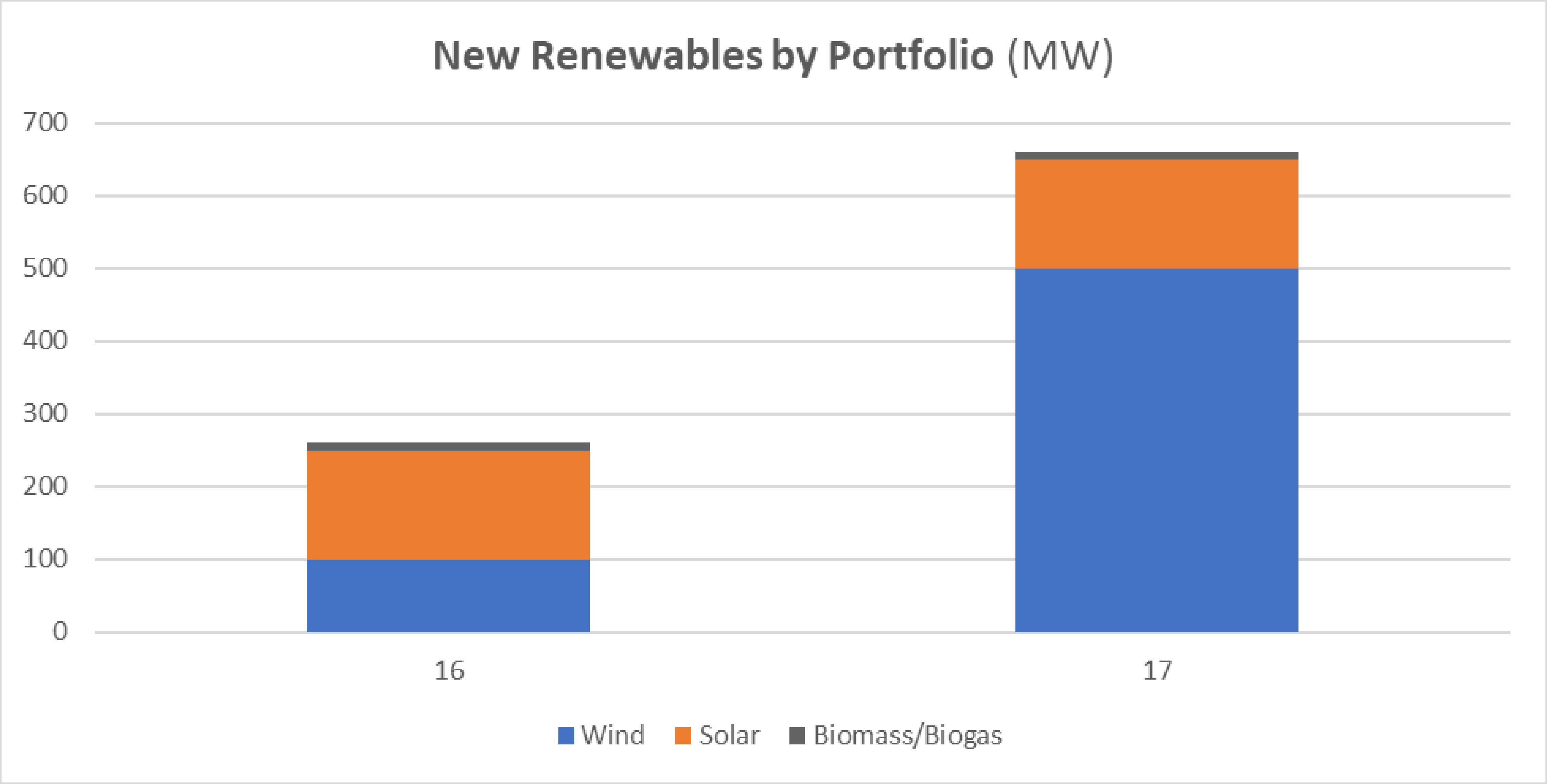


	16	17
Biomass/Biogas	10	10
Geothermal	10	10
Gas	523	156
Demand Response	52	76
Battery	75	417
Solar	150	150
Wind	100	500

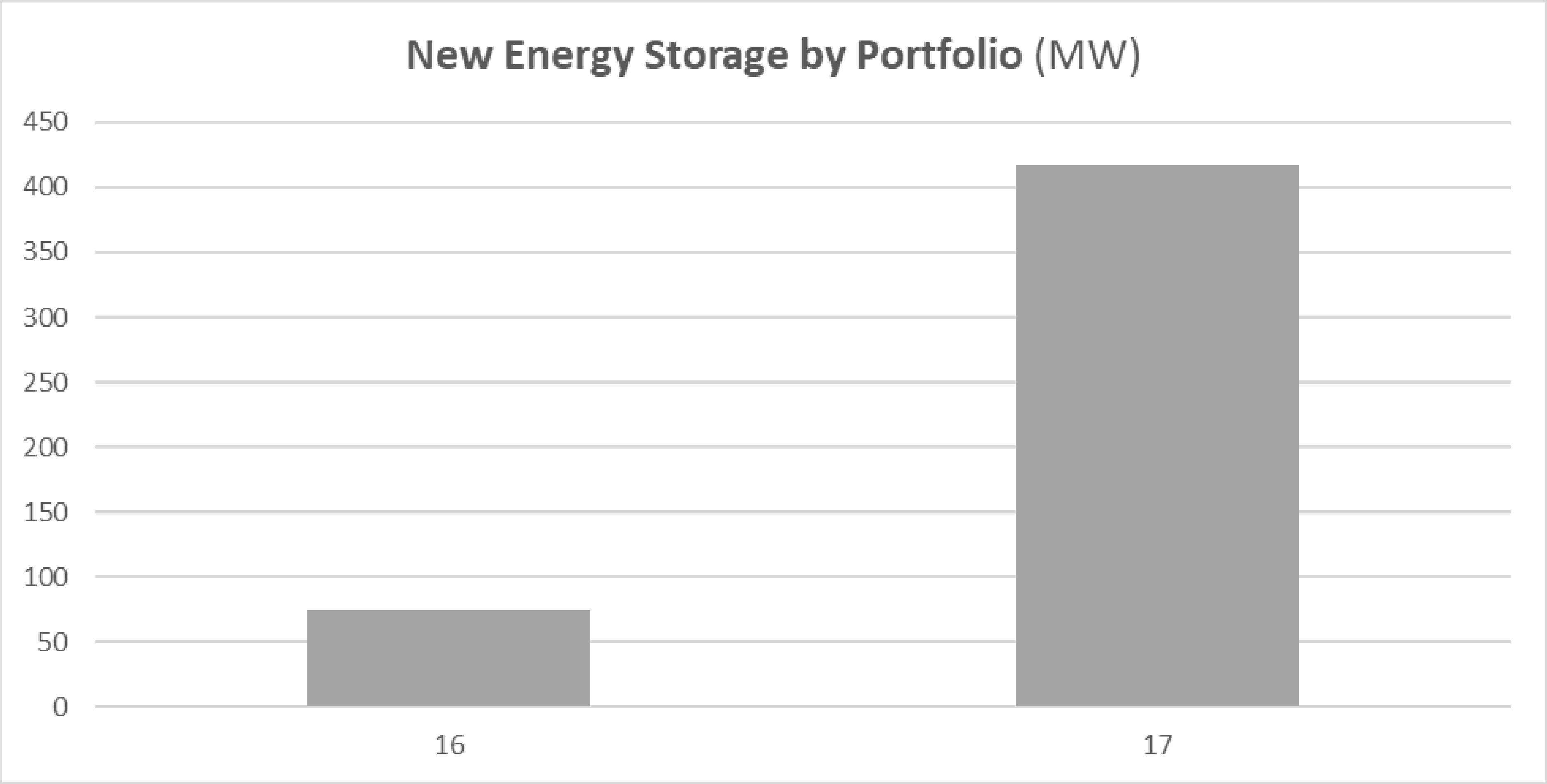
DSM Resources by Portfolio



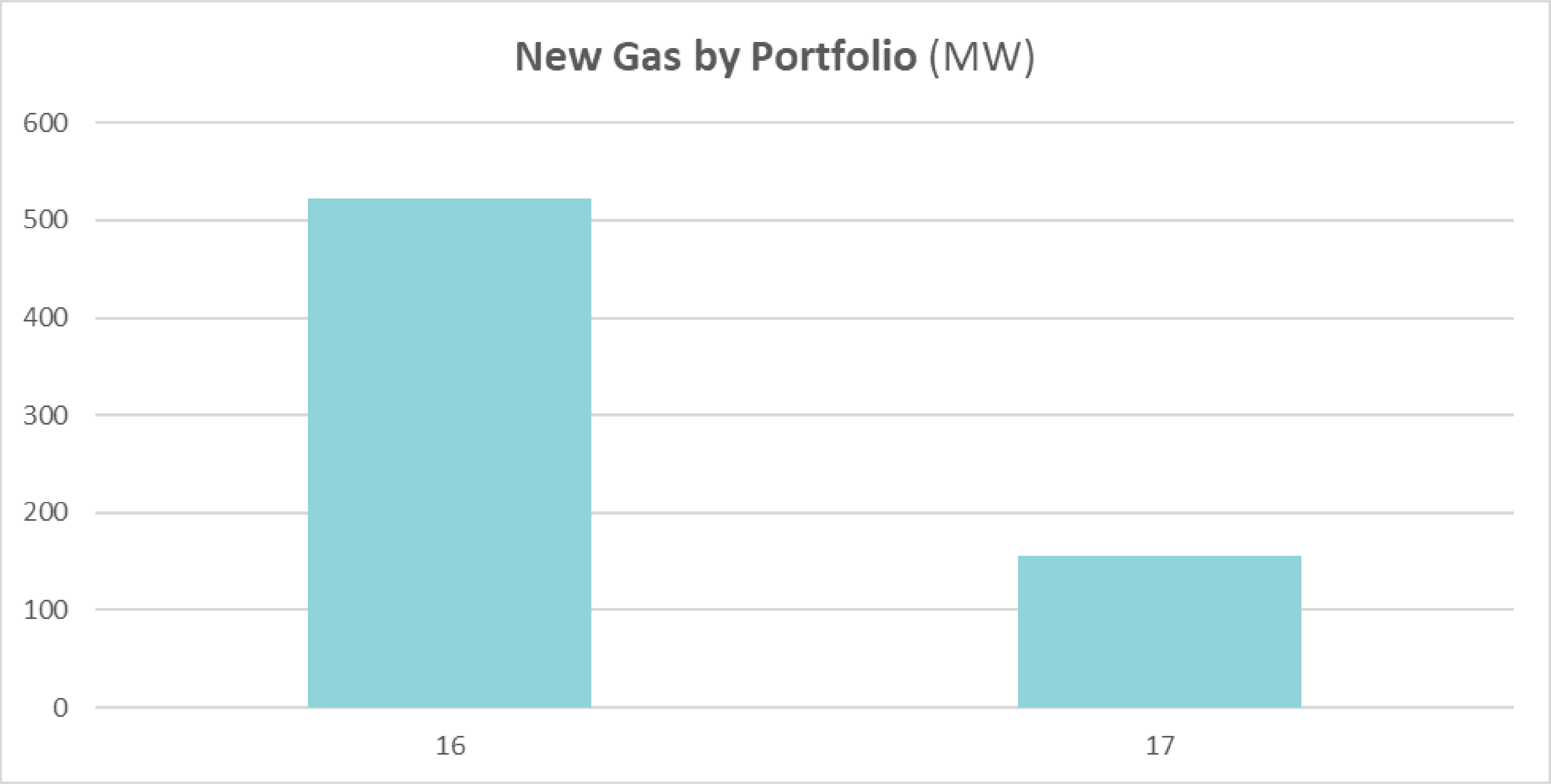
Renewable Resources by Portfolio

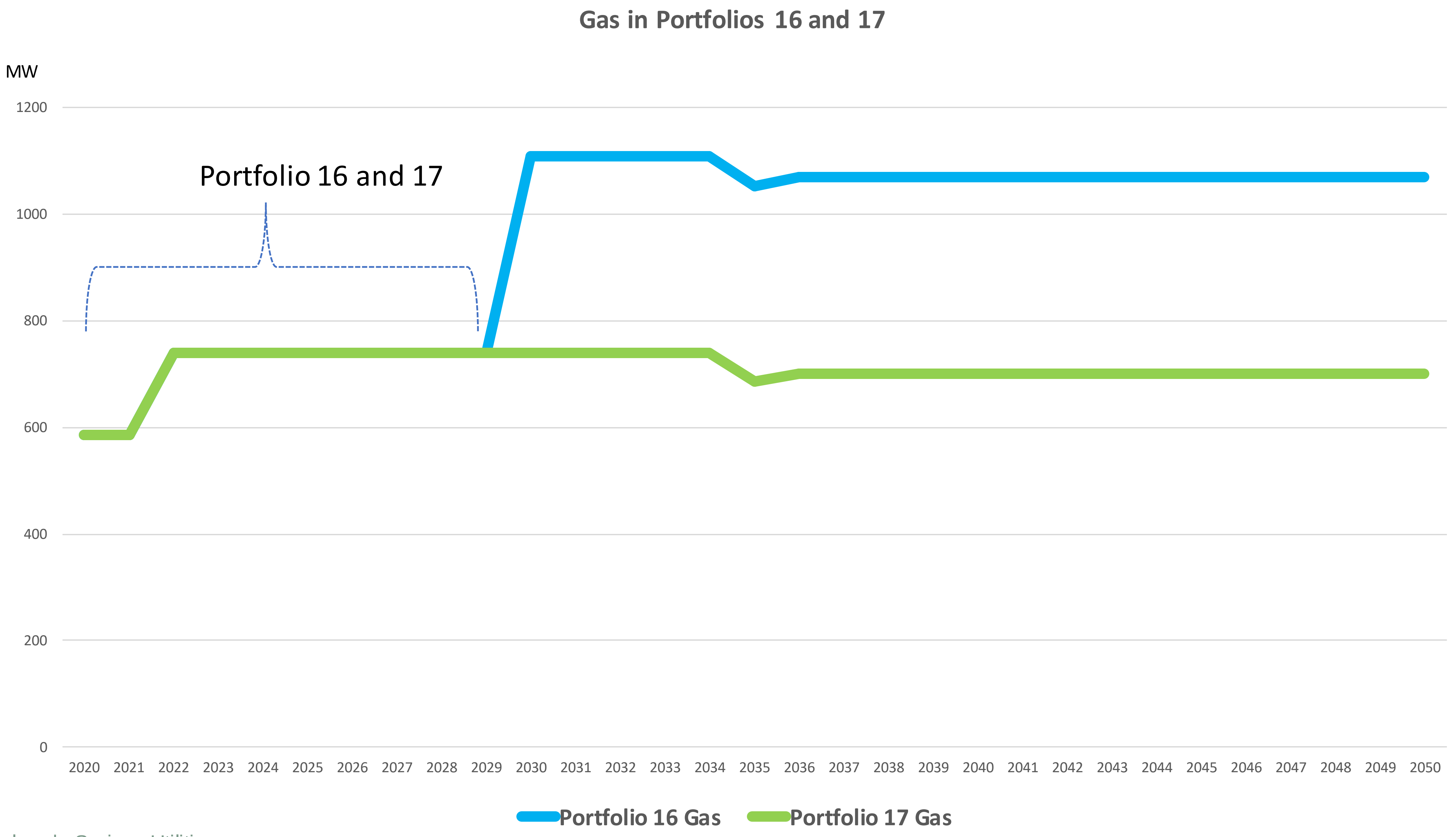


Energy Storage Resources by Portfolio



Gas Resources by Portfolio




Gas in Portfolios 16 and 17
MW
1200
1000
800
600
400
200
0
Portfolio 16 and 17
2020
2021
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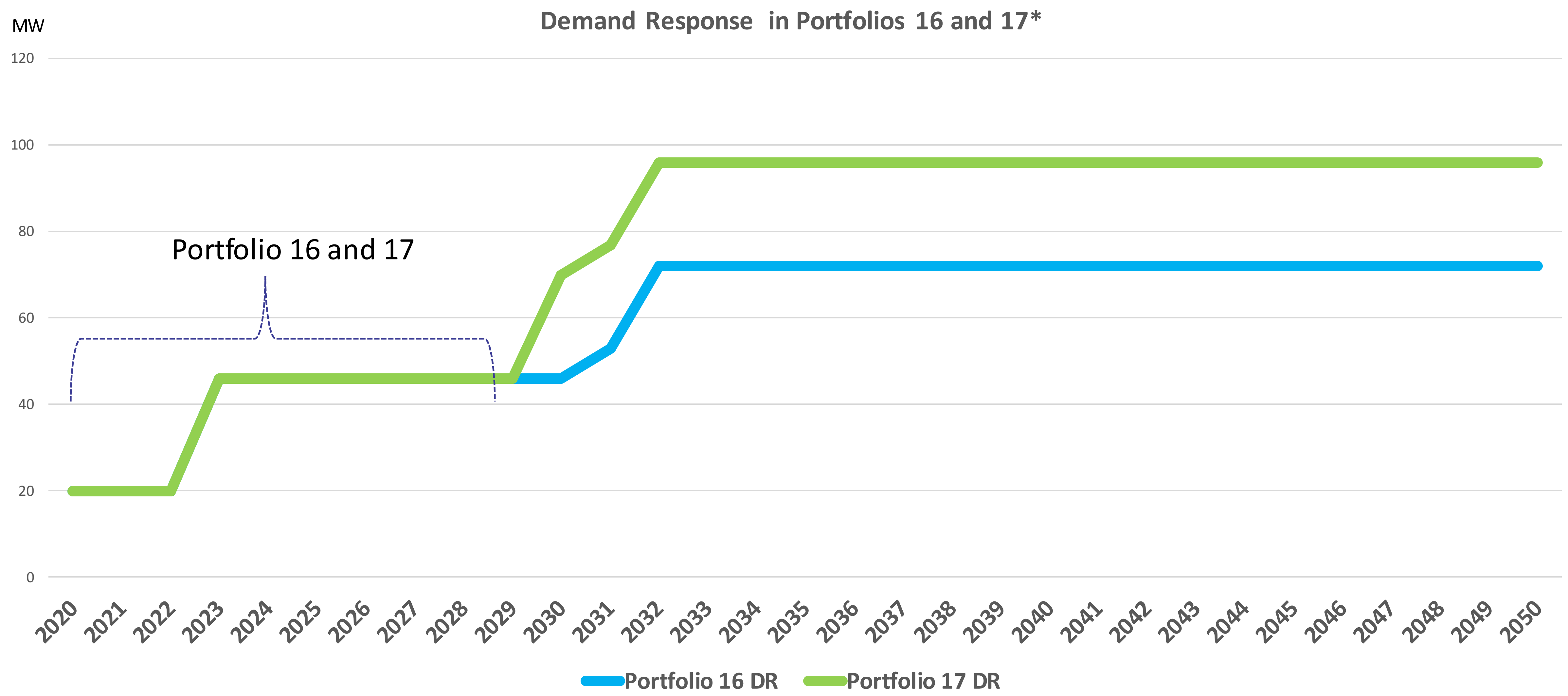
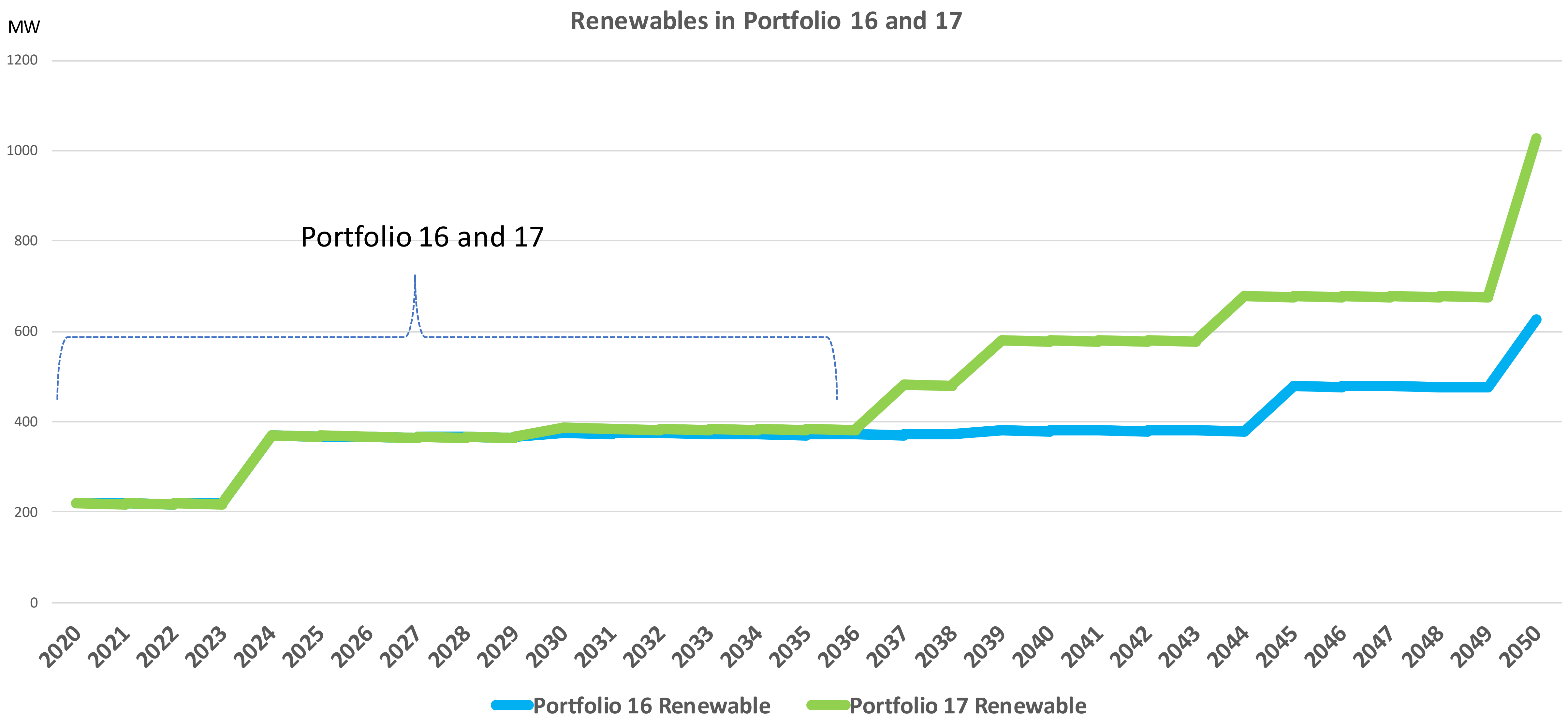
2050
Portfolio 16 Gas
Portfolio 17 Gas

MW



*Savings from energy efficiency is the same for each portfolio


Renewables in Portfolio 16 and 17
MW
1200
1000
800
600
400
200
0
Portfolio 16 and 17
2020
2021
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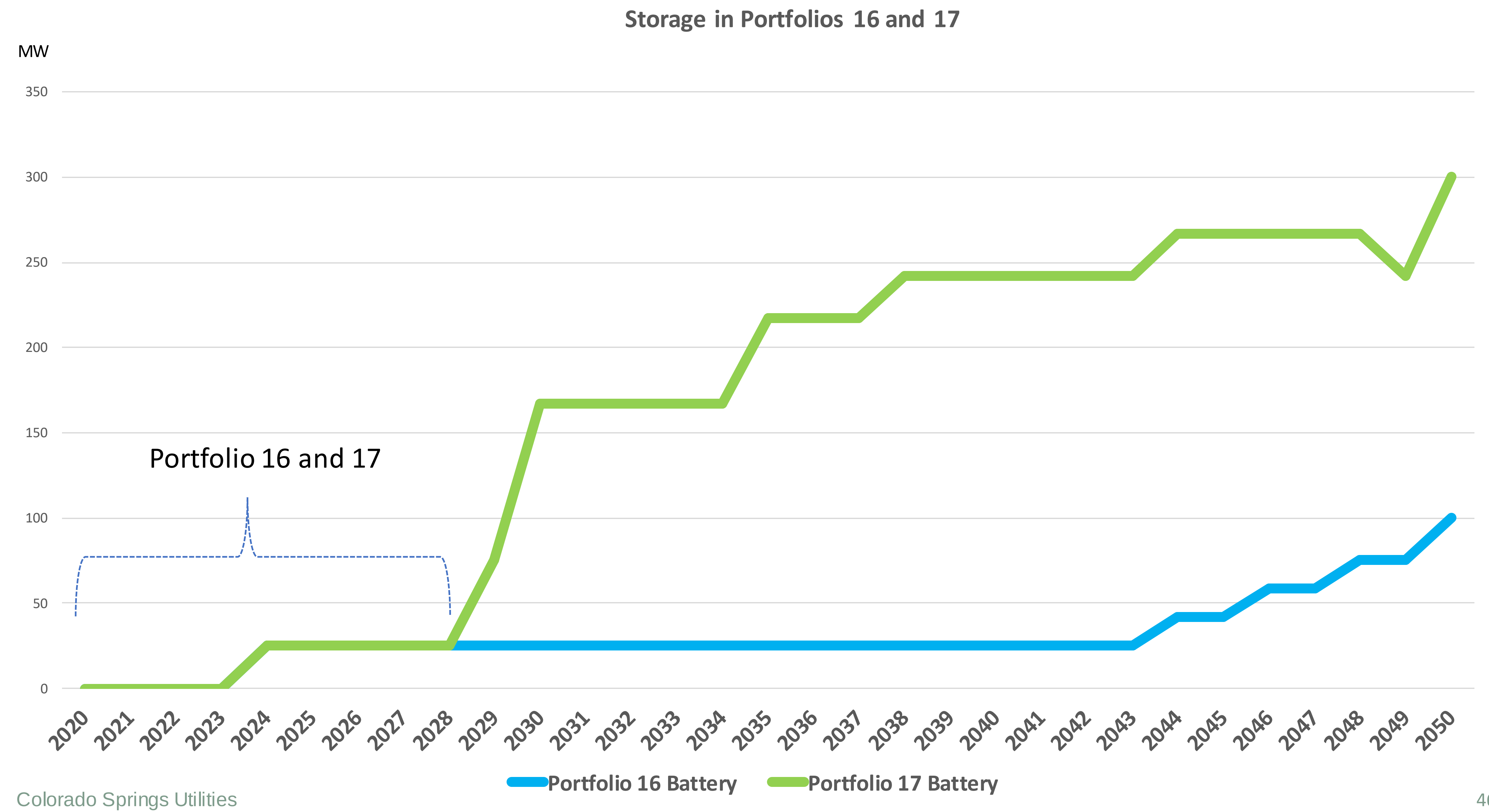
2050
Portfolio 16 Renewable
Portfolio 17 Renewable



Storage in Portfolios 16 and 17
MW
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50
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Portfolio 16 and 17
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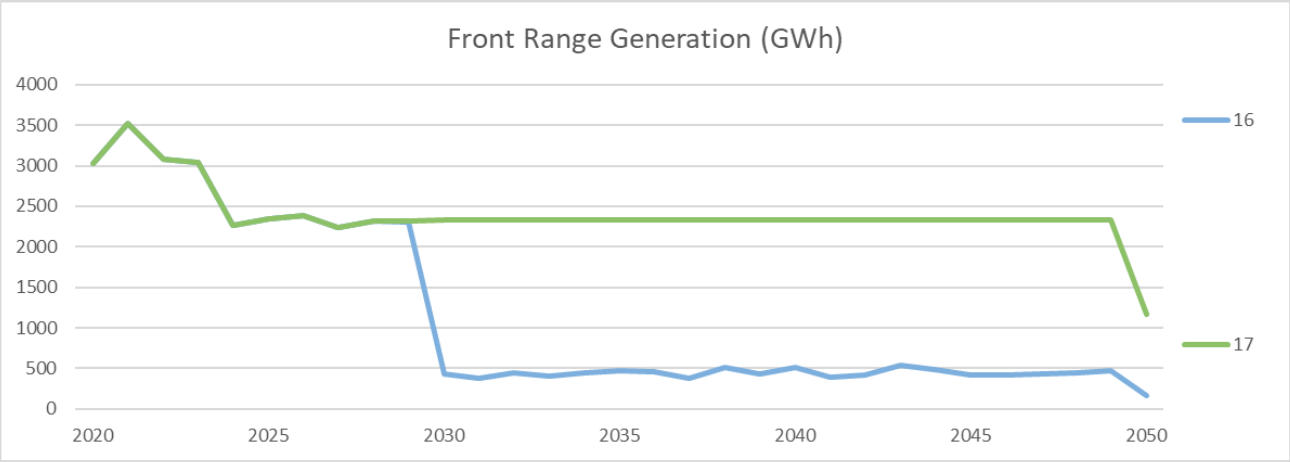
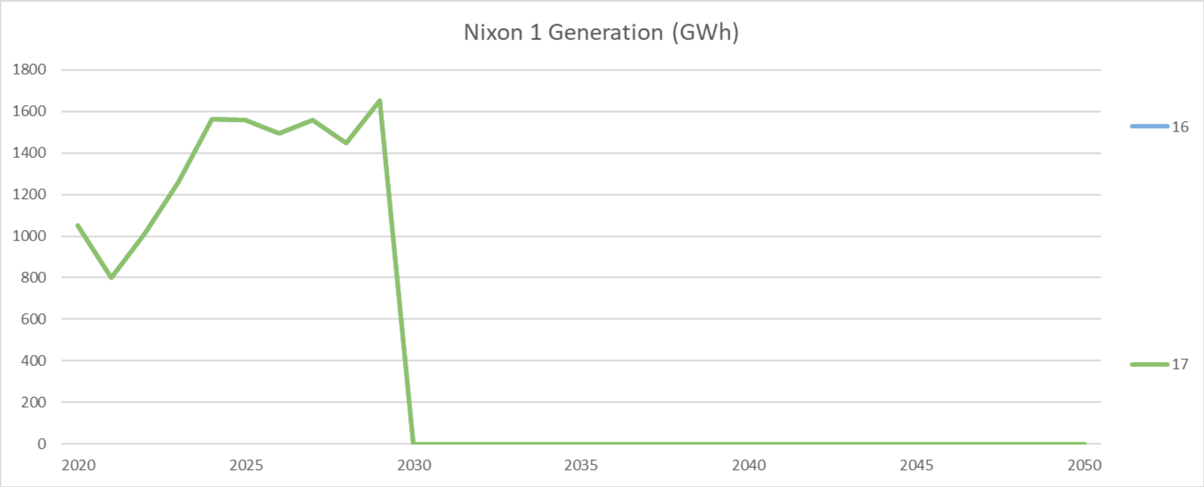
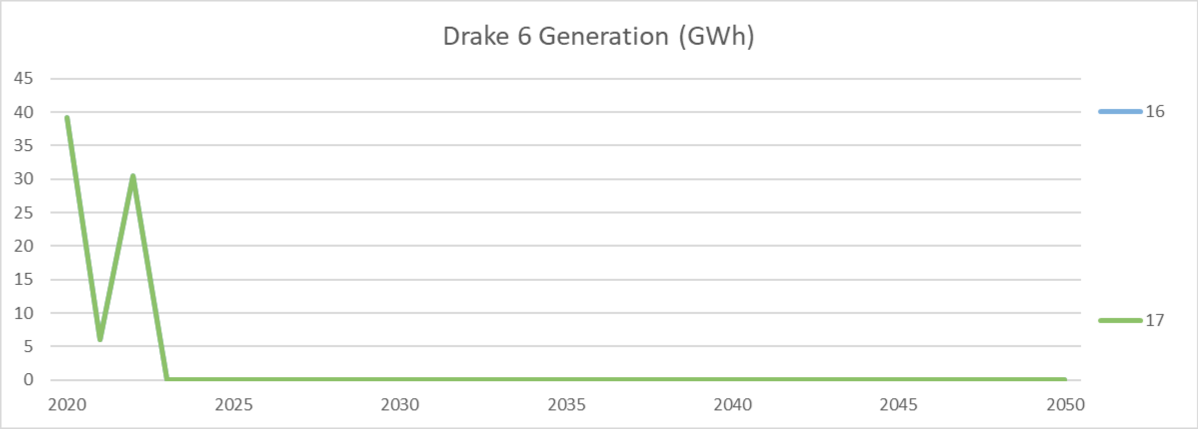
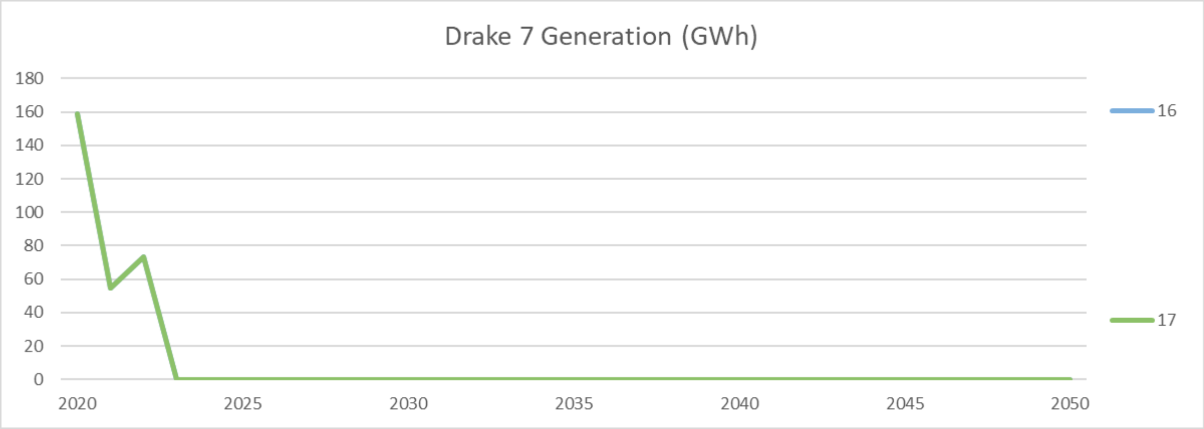
Portfolio 16 Battery
Portfolio 17 Battery

Unit Generation

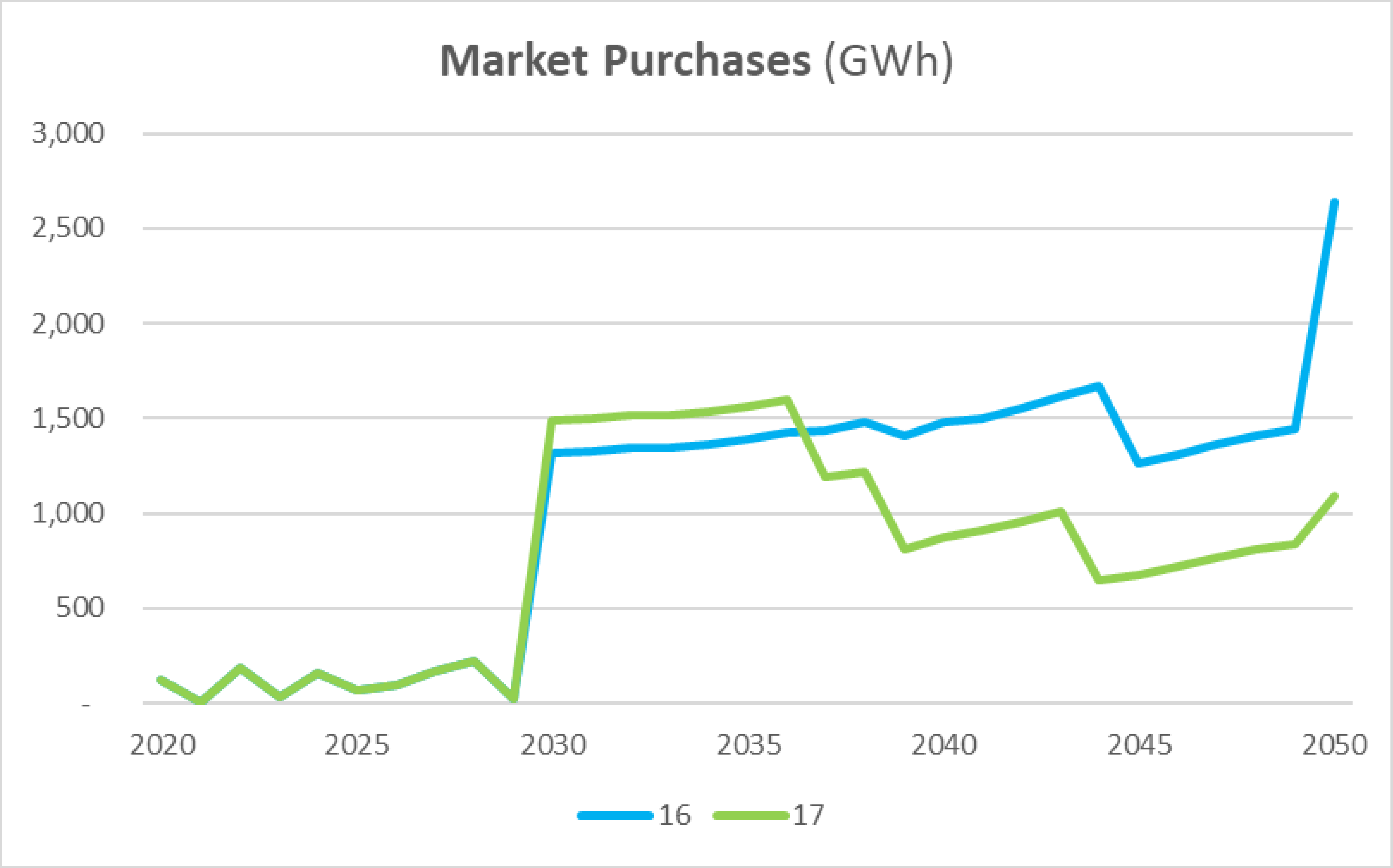








Market Purchases



100% Renewable Portfolios

Portfolio	CO2 Target	Retirements	New Resources	Attribute Ranking	Total Score Normalized	Reliability	Cost / Implementation	Environment / Stewardship	Flexibility / Diversity	Innovation
15	100% by 2030	Drake/Nixon/Front Range 2030	Renewable/Storage/DSM	8	82.8	73	24	100	50	60
18	100% by 2040	Drake 2035 Nixon/Front Range 2040	Renewable/Storage/DSM	10	74.2	80	34	53	50	60
19	100% by 2050	Drake 2035 Nixon/Front Range 2050	Renewable/Storage/DSM	12	67.3	73	44	38	63	30

Energy Vision

Provide resilient, reliable and cost-effective energy that is environmentally sustainable, reduces our carbon footprint and uses proven state-of-the-art technologies to enhance our quality of life for generations to come.

THE FUTURE OF OUR ENERGY SYSTEM

As we decommission fossil fuel generation and integrate more renewables, it is essential that we maintain a safe, reliable, and cost-effective energy supply. Here's how we'll do it.

1 TODAY, WE HAVE ABOUT 1,000 MEGAWATTS OF FOSSIL FUEL ELECTRIC GENERATION. IN THE COMING YEARS, WE WILL DECOMMISSION MORE THAN A QUARTER OF IT.

2 THE COMMUNITY INCORPORATES SMART TECHNOLOGY (INCLUDING SOLAR PANELS, STORAGE SYSTEMS, AND ELECTRIC VEHICLES) IN THEIR HOMES AND BUSINESSES AND PARTICIPATES IN ENERGY EFFICIENCY, REDUCING THE AMOUNT OF NEEDED REPLACEMENT GENERATION.

3 OUR COMMUNITY AND ENVIRONMENT BENEFIT FROM UTILITY-SCALE SOLAR AND STORAGE PROJECTS (GROWING CARBON-FREE GENERATION TO MORE THAN 260 MEGAWATTS BY 2023).

4 MINIMAL AMOUNTS OF NATURAL GAS GENERATION CAN BE OUR BRIDGE TO NEW TECHNOLOGIES.

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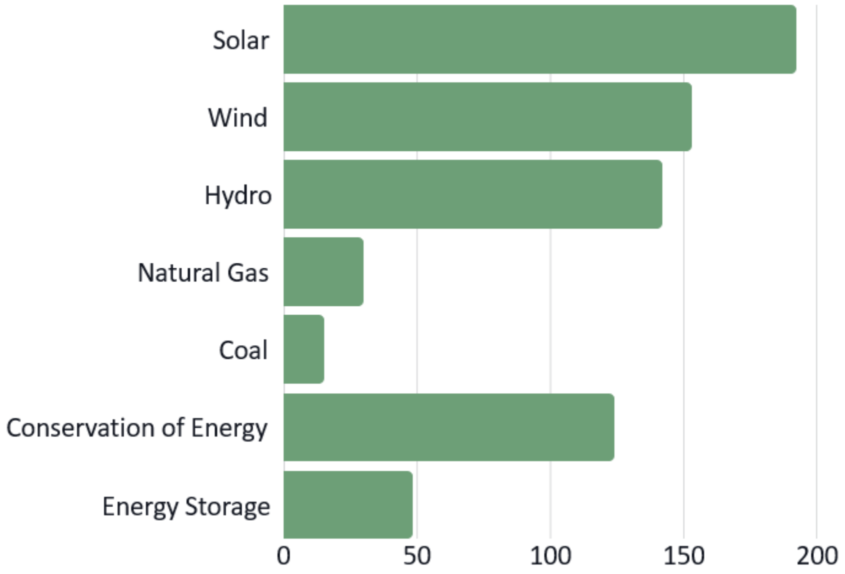
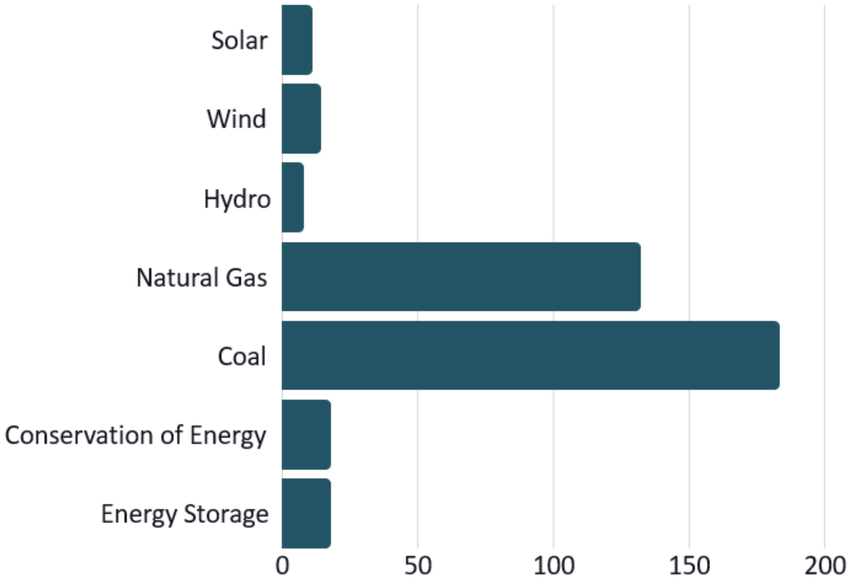
Youth Input

DO YOU HAVE A POSITIVE OR NEGATIVE OPINION OF THE FOLLOWING ENERGY SOURCES?

OF POSITIVE OPINIONS OF EACH ENERGY SOURCE

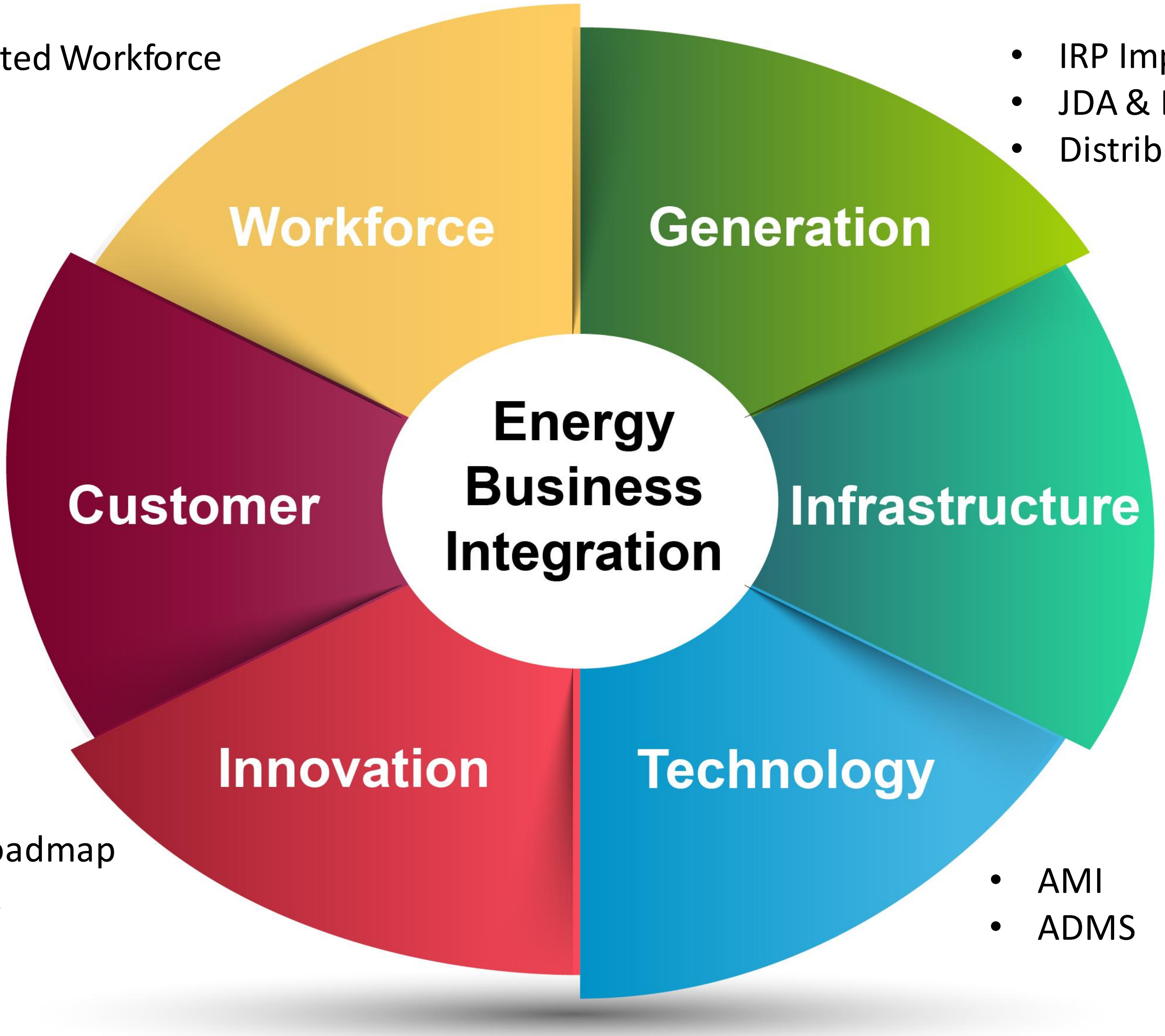


OF NEGATIVE OPINIONS OF EACH ENERGY SOURCE



- Integrated Workforce Plan

- IRP Implementation
- JDA & Energy Markets
- Distributed Generation Siting



- Rate Modernization and Customer Outreach

- Transmission Projects
- Military Resilience
- Drake Studies

- Energy Roadmap
- DSM/DER

- AMI
- ADMS