CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

2018
Integrated Resource Plan

February 6, 2018

CASCADE NATURAL GAS CORPORATION
2018 INTEGRATED RESOURCE PLAN
TABLE OF CONTENTS

TABLE OF CONTENTS

SECTION 1

EXECUTIVE SUMMARY

Introduction

> **Key Points**
> - Cascade's first resource deficiency is in 2020.
> - The Company's two-year action plan provides the road map for resource acquisition.
> - Load growth is forecasted to be 1.58% per year, or 34.6% over the 20-year planning horizon.
> - The total avoided cost ranges between $0.4204/therm and $1.2078/therm over the 20-year planning horizon.
> - Cascade projects 11.86 million therms of energy efficiency in Oregon over the 20-year planning horizon.
> - This plan was informed by five Technical Advisory Group meetings, with active engagement by stakeholders.
> - Cascade is fully committed to the IRP process, with significant new administrative approaches.
> - Each section provides an *at-a-glance* summary of the key points.

Cascade Natural Gas Corporation's (Cascade or the Company) Integrated Resource Plan (IRP or Plan) forecasts 20 years of expected system-wide customer and demand growth, and analyzes the most reliable and least cost supply side and demand side resources that could be used to fulfill future customers' gas service needs. Predicting how to best meet customers' future demand includes the consideration of possible policy changes and the resulting impact on customer prices, the Company's operations, and the ability of Cascade's distribution system to serve gas reliably as regional demand increases. This plan discusses these elements that impact how the Company may serve its customers from 2018 through 2037. While the Plan cannot predict the future, it is a useful guide. Below is a short summary of each section included in this IRP. The details regarding methodologies as well as specific results are found in the sections and the appendices.

Section 2: Company Overview

Cascade has been providing gas service since 1953. Over the past 60 plus years, the Company has expanded its service territory by purchasing and merging with other small natural gas utilities. As of 2007, Cascade is a subsidiary of Montana Dakota Utilities (MDU) Resources Group, Inc. based in Bismarck, North Dakota, that owns and operates four distinct energy utilities.

Cascade serves over 282,000 customers located in smaller, rural communities across the states of Oregon and Washington. The Company's service territory poses challenges for operating an energy distribution system including the fact that the areas served are noncontiguous and the weather in each area can be vastly different. To capture this, Cascade groups its citygates into seven weather zones.

Cascade purchases natural gas from a variety of suppliers and transports the gas to its distribution system using three natural gas pipeline companies. Northwest

Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta gas, and Enbridge (Westcoast Transmission) provides access to British Columbia gas directly into the Company's distribution system.

Section 3: Demand Forecast

Forecasting demand is useful for both long- and short-term planning. The Company began its demand forecasting process by looking at each citygate serving firm or uninterruptible service. These citygates were then assigned a weather zone because a significant portion of Cascade's customer usage fluctuates with the weather.

Cascade developed a normal, or expected, future weather year by shaping 30 years of proprietary, historical weather data. Heating degree day (HDD) values were assigned to each day in the model weather year. To ensure the Company will be able to serve its firm customers during extreme weather, the Company tested the model weather year three times, each time with a unique extreme weather event. The Company tested an average peak HDD (the average coldest day for each year in the last 30 years), a system-wide max peak HDD (the system-wide, single coldest day recorded in the last 30 years), and a max citygate peak HDD (the coldest HDD for each weather station in the last 30 years).

Peak day demand was then derived for each weather scenario by applying the HDD to the peak day forecast for each citygate.

Demand forecasting first requires a customer forecast. The Company developed a unique customer forecast for each county by incorporating population and employment growth data from Woods and Poole as well as from internal market intelligence into an ARIMA model.

Load growth across Cascade's system through 2037 is expected to increase by a range of 1.50% and 1.65% annually after smoothing the leap year anomaly. Load growth is split between residential, commercial, and industrial customers with residential and commercial customer classes expected to grow at a rate near 1.4-1.6% annually, while industrial expects a growth rate of around 1.9%.

After determining system-wide demand over the planning period by multiplying the use per customer times the number of customers in the forecast, Cascade stress tested its results with high and low scenarios for varying future economic conditions.

In absolute numbers, system load under normal weather conditions is expected to exceed 417 million therms in 2037. Residential customers are expected to grow from 53.1% of the total core load to 54.1% of the total core load by 2037.

Load across Cascade's two-state service territory is expected to increase 34.6% over the planning horizon, with the Oregon portion outpacing Washington at 41.6% versus 32.2%.

Section 4: Supply Side Resources

Section 4 provides an in-depth description of the supply side options the Company considered in this Plan.

Cascade's gas supply portfolio is sourced from three areas of North America: British Columbia, Alberta, and the Rockies. The Company secures its gas through firm gas supply contracts and open market purchases.

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except for during *force majeure* conditions. Supply contract terms for firm commodity supplies vary greatly with some contracts specifying fixed prices, while others are based on indices that float from month to month. Open market purchases are short-term and are subject to more volatile pricing.

The Company evaluates its demand curve and defines four categories of supply for meeting its demand. First are base load supply resources which are used for the constant demand that occurs all year and does not fluctuate based on weather. Base load supplies are meant to be taken day in and day out, 365 days a year. Next are winter supplies which meet demand occurring due to cooler weather. Winter gas supplies are firm gas supplies that are purchased for a short period during the winter months to cover increased loads, primarily for space heating. The contracts are typically three to five months in duration (primarily November through March which is commonly referred to as the heating season). Next are peaking gas supplies which are used when colder weather spikes demand. Peaking gas supplies, similar to storage, are firm contracts purchased only as load actually materializes due to high winter demand. That is, the seller must deliver the gas when the Company requires it, but the Company is not required to take gas unless it is needed to meet customer load requirements. Last are needle peaking resources which are utilized during severe or arctic cold snaps when demand increases sharply for a few days. These resources are usually very expensive and are normally utilized for short periods of time.

Cascade also utilizes natural gas storage to meet a portion of the requirements of its core market. Storing gas supplies, purchased and injected during periods of low demand, is a cost-effective way of meeting peak requirements of Cascade's firm market. Cascade does not own any storage facilities and, therefore, contracts with storage owners to lease a portion of those owners' unused storage capacity.

Cascade has contracted for storage service directly from Northwest Pipeline since 1994 at their Jackson Prairie and Plymouth facilities. Jackson Prairie is located in

Lewis County, Washington, approximately ten miles south of Chehalis. Plymouth is located in Benton County, Washington approximately 30 miles south of Kennewick. Both Jackson Prairie facilities and the Plymouth facility are located directly on NWP's transmission system. Therefore, storage withdrawal rates can be changed several times during a gas day to accommodate weather driven changes in core customer requirements.

Cascade uses interstate pipeline transportation resources to deliver the firm gas supplies it purchases from three different regions or basins. Cascade has over 30 long-term annual contracts with NWP, numerous long-term annual and winter-only transportation contracts with GTN (including the upstream capacity on TransCanada Pipeline's Foothills and Alberta systems), a long-term, winter-only contract with Ruby Pipeline, and one long-term annual contract with Enbridge (Westcoast Transmission) in British Columbia, Canada. These contracts do not include storage or other peaking services that may provide additional delivery capability rights ranging from nine to 120 days.

In order to evaluate the price of resource options, the Company analyzed gas price forecasts from various sources. Cascade used Wood Mackenzie, the EIA, NWPCC, and Cascade's trading partners to develop a blended long-range price forecast. With a monthly Henry Hub price from the above sources, the Company assigned a weight to each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. These weights were derived by calculating the Symmetric Mean Absolute Percentage Error (SMAPE or Errors) of each source versus actual Henry Hub pricing since 2010. The inverse of these Errors was then used to determine the weight given to each source.

In order to determine the low case and high case, the Company utilized the EIA economic growth factors which are 1.6 for the Low Case, 2.2 for the Reference Case, and 2.6 for the High Case.[1]

Besides currently used resources, Cascade considered alternative resources. Other potential incremental capacity options evaluated included: the cross-Cascades Trail-West pipeline; additional GTN capacity, NWP Eastern Oregon Expansion, NWP Express Project or the I-5 Sumas expansion project, NWP Wenatchee Expansion, NWP Zone 20 (Spokane) Expansion, Pacific Connector. Other storage options considered were: AECO, Gill Ranch Storage, Mist (the North Mist III expansion), Ryckman Creek Storage, and Wild Goose Storage.

Cascade also considered unconventional supplies such as satellite LNG, bio-natural gas, and the realignment of its Maximum Daily Delivery Obligations (MDDOs) on NWP.

[1] EIA 2017 Annual Energy Outlook

Long-term planning is not an exact science and the Company has considered various risks that may challenge the assumptions used in this analysis. Risk can stem from potential Federal Energy Regulatory Commission (FERC) or Canada's National Energy Board (NEB) rulings that may impact the cost or availability of gas. The Company also considers the risk that firm supply may not be available when Cascade needs it or that pricing could vary due to any factor impacting the economy of supply and demand.

To mitigate risk, Cascade constantly seeks methods to ensure price stability for customers to the extent reasonable. In addition to methods such as long-term physical fixed price gas supply contracts and storage, another means for creating stability is through the use of financial derivatives. Derivatives generally lock-in a forward natural gas price with a hedge, consequently eliminating exposure to significant swings in rising and falling prices. The Company's internal Gas Supply Oversight Committee (GSOC) provides oversight and guidance for the Company's gas supply hedging strategy.

Section 5: Avoided Costs

The avoided cost is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. Avoided cost forecasts are used to establish a cost-effective threshold for demand side resources. If demand side resources cost as much as or less than the avoided cost, then the demand side resource is cost-effective and should be the next resource added to the Company's stack of resources.

Cascade's avoided cost includes fixed transportation costs, variable transportation costs, fixed storage costs, variable storage costs, commodity costs, a carbon tax, a 10% adder, and a hedge premium. Essentially, the avoided cost is the cost of the Company's resource stack on a per therm basis plus three values for benefits specifically acquired with energy efficiency.

The largest part of the avoided cost is the cost of gas. A carbon tax forecast was added in anticipation of carbon legislation. The Company included carbon at $10 per ton in 2018 with this cost of carbon escalating to $60 by 2038. This is based on a 2013 study performed by Portland State University.

Next, 10% is added to the total avoided cost to account for nonquantifiable, environmental benefits. This 10% adder was first recommended by Northwest Power and Conservation Council (NWPCC) and was later adopted by the Oregon legislature as a requirement.[2]

[2] *See* ORS 469.631(4)

Thirdly, a risk value premium was added to account for the avoidance of hedging costs. This is the first Oregon IRP wherein a hedging value has been included in the Company's avoided cost. The Company sees this addition as a refinement to its avoided cost valuation process.

While the Company looked at including costs for avoided or delayed investments in distribution infrastructure, the resulting valuation was negligible. In future IRPs, the Company will continue analyzing the value for avoided distribution investments.

The Company also considered the impact of price elasticity on demand. For the 2018 IRP, the system avoided costs range between $0.4204/therm and $1.2078/therm over the 20-year planning horizon. The increase over time is largely driven by the escalating cost of carbon. For Cascade's 2018 IRP, a short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 was used. The Company determined this was reasonable as it is consistent with regional studies and other utilities' modeling efforts.

Section 6: Demand Side Management and Environmental Policy

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency measures such as insulation, more efficient gas-fired appliances or through load management programs. Cascade targets savings of approximately 41 million therms systemwide over the 20-year planning horizon; 11.86 million therms in Oregon and 29 million therms in Washington.

Cascade acquires therm savings through its energy efficiency programs. In Oregon, the Energy Trust of Oregon (Energy Trust) administers the Company's programs and in Washington, Cascade administers its own programs. In both states the programs offer Cascade customers financial incentives to install specific cost-effective energy efficiency measures. These measures cover a broad range of applications including new homes, retrofit appliances, and commercial appliances. The programs are funded in Oregon through a public purpose charge, which applies a percentage charge to customers' bills, and in Washington through a per therm charge.

To determine the Company's savings targets in Oregon, Energy Trust performed a resource analysis of all available energy efficiency for the 20-year planning period. This was a multi-step process beginning with determining all available and potentially available conservation measures. A demographic study of the age of the houses and buildings in Cascade's Oregon service territory was then performed to estimate when new buildings and homes would be built, and when existing homes would need replacement appliances. The total amount of energy savings that can be installed in an area without consideration of economic barriers is called the technical potential.

Once Energy Trust determined the technical potential, they used the industry standard of decrementing this by 15% to get to the achievable potential. Energy Trust then created the cost-effective potential by screening all DSM measures using the total resource cost (TRC) test, which is a benefit-cost ratio (BCR) that measures the cost effectiveness of the investment being made in an efficiency measure. The cost-effective achievable potential is smaller than the achievable potential because the potential savings from non-cost-effective measures are removed.

Energy Trust then applied its knowledge of market uptake to the cost-effective achievable potential which further reduced this amount and resulted the program savings projections which are included in Appendix D by customer class, program and year.

Each measure comprising the cost-effective achievable potential was given a levelized cost which is that measure's annualized cost over annual therm savings. The levelized cost is used to demonstrate the total potential therms that could be saved at various costs. The levelized costs per measures in the 2018 IRP's cost-effective achievable potential are higher than they were in the 2014 IRP for two reasons: 1) The therm savings targets in this IRP include savings from non-cost-effective measures that the Commission is allowing the Energy Trust to incent; and 2) The price of gas has decreased over the last five years.

The program savings projections included in this IRP are higher than those presented in the Company's 2014 IRP for the following reasons: 1) New measures were considered in the analysis; 2) Measure assumptions were updated based on more current data; 3) Emerging technologies were included in the analysis; and 4) Updated measure saturation rates from third-party research and survey work were used.

Section 6 also considers environmental policies being both enacted and considered in Oregon, Washington, and nationally. A number of initiatives intended to reduce, eliminate, or mitigate the effects of greenhouse gases on the atmosphere are in play. Carbon legislation will be a reality in a matter of time, as Washington adopted carbon regulations in 2016. At the time of this IRP filing, the Company is in the process of complying with this policy.

The Company follows all carbon related initiatives closely as they will impact the gas retail business in some way. A carbon tax will raise customers' prices: initiatives such as Portland's goal of being 100% renewable by 2050, or Ashland's and Eugene's plans to reduce carbon emissions will reduce natural gas usage. Carbon policies will also increase the Company's avoided costs thus increasing cost-effective energy savings potential. Policies addressing climate change are likely to impact all factors in integrated resource planning (e.g. demand forecasts, pricing, and DSM potential) and, therefore, must be closely monitored.

Section 7: Resource Integration

Cascade utilizes SENDOUT® for resource optimization. This software permits the Company to develop and analyze a variety of resource portfolios to help determine the type, size, and timing of resources best matched to forecast requirements. The model knows the exact load and price for every day of the planning period based on input and can therefore minimize costs in a way that would not be possible in the real world. It is important to acknowledge that SENDOUT® provides helpful but not perfect information to guide decisions.

One of the purposes of integrated resource planning is to identify an illustrative resource portfolio to help guide specific resource acquisitions. In this planning cycle, the Company considered a host of resource alternatives that can be added to its resource portfolio, including additional conservation programs, incremental off-system storage alternatives at the AECO Hub, Mist, Ryckman Creek, Wild Goose, and Gill Ranch storage facilities. Additionally, incremental transportation capacity on NWP, Ruby, NGTL, Foothills and GTN pipeline systems was considered, along with on-system satellite LNG facilities, bio-natural gas, and imported LNG. Typically, utility infrastructure projects are “lumpy,” since demand grows annually at a small percentage rate, while capacity is typically added on a project-by-project basis. Utilities often have surplus capacity and must “grow into” their new pipeline capacity, because it is more cost-effective for pipelines to build for several years of load growth at one time than to make small additions each year. However, the Company can minimize the impacts through the acquisition of citygate peaking resources which include both the supplies and the associated pipeline delivery for a certain number of days or through the purchase of other’s excess capacity through short- or medium-term capacity releases.

Even after the savings from energy efficiency programs are realized, Cascade will need to acquire additional capacity resources or enter into other supply arrangements to meet anticipated peak day requirements, primarily due to continued growth in the Company’s residential and commercial customer base. Utilizing the SENDOUT® resource optimization model, several scenarios were run to test the viability of acquiring incremental storage and transportation resources either based on existing recourse rates and discounted rates, and via capacity release through a third party. Basin prices in the model over the 20-year planning horizon have AECO trading at a discount to Rockies, Malin, and Sumas. The acquisition of additional traditional pipeline capacity is the most reasonable resource to address most capacity shortfalls on a peak day.

Using input from these alternative resources discussed, SENDOUT® derives a portfolio of existing and incremental resources that Cascade defines as the Preferred Portfolio. This provides guidance as to what resources should be considered to reduce unserved demand with the best combination of expected costs and associated risks, and uncertainties for the utility and its customers under expected pricing, weather, and growth environments.

The 20-year portfolio costs are expected to range between \$3,558,879,000 to \$3,978,920,000 for the planning period, with an average cost per therm ranging between \$0.507 and \$0.551.

A more detailed discussion regarding the Company's resource integration and the results can be found in Section 7, Resource Integration, beginning on page 7-19.

Section 8: Distribution System Planning

Cascade uses computer modeling for network demand studies to ensure its distribution system is designed to deliver gas reliably to customers as the number of customers and their demand change.

Cascade's geographical information system (GIS) keeps an as-to-date record of pipe and facilities, complete with all system attributes such as date of install and operating pressures. Using the Company's geographical information system (GIS) environment and other input data, Cascade is able to create system models through the use of Synergi® software. This software provides the means to theoretically model piping and facilities to represent current pressure and flow conditions while predicting future events and growth. Combining these models with historical weather data can provide a Design Day model that will predict a worst-case scenario. Design Day models that experience less than ideal conditions can then be identified and remedied before a real problem is encountered.

When modeling demonstrates that a portion of the distribution system is unable to meet future demand, Cascade engineers consider all possible remedies including reinforcements or expansions. Enhancements include pipeline looping, upsizing, and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. Pipeline upsizing involves replacing existing pipe with a larger size pipe. Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline.

Besides modifying the pipelines, regulators or regulator stations can be added to reduce pipeline pressure at various stages in the distribution system. If pressures are too low, compressor stations can be added to boost downstream pressures.

Another possible solution is targeted conservation. Area specific incentives for installed energy efficiency measures can reduce demand in a constrained area either eliminating or forestalling the need to add or reinforce infrastructure.

Once the best solution is determined, projects are ranked based on numerous criteria and are scheduled. Section 8 presents three sample projects and Appendix I lists all known distribution projects.

Section 9: Stakeholder Engagement

Input and feedback from Cascade's Technical Advisory Group (TAG) is an important resource for ensuring the IRP includes perspectives beyond the Company's and is responsive to stakeholders' concerns. Cascade held four public TAG meetings with internal and external stakeholders. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest local distribution companies (LDCs), Commission Staff, stakeholder representatives such as the Northwest Gas Association, Citizens' Utility Board, and the Northwest Industrial Gas Users. Cascade has a dedicated Internet webpage where customers and parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs. This information can be found at https://www.cngc.com/rates-services/rates-tariffs/oregon-integrated-resource-plan.

Section 10: Two-Year Action Plan

Table 1-1 shows Cascade's Two-Year Action Plan. Further descriptions can be found in Section 10, Two-Year Action Plan.

Table 1-1: Highlights of Draft 2018 Action Plan

Functional Area	Anticipated Action	Timing
Demand Forecast	Expanding forecast to test Auto-ARIMA functionality in R.	Beginning in 2018 for 2020 IRP
Supply Side Resources	Active participation in meetings related to UM-1720 to ensure Cascade engages in best practices related to hedging.	Ongoing, for inclusion in 2020 IRP
DSM	The Company will acquire cost-effective therm savings by partnering with Energy Trust in Oregon and by delivering programs under the oversight of the Company's Conservation Advisory Group in Washington.	Ongoing, for inclusion in 2020 IRP
DSM	The Company will examine the impact changes such as revised building codes, OPUC exemptions granted for non-cost-effective measures, and changes to avoided cost calculations stemming from Docket No. UM 1893, may have on the Company's long- and short-term conservation potential.	Summary will be provided in the 2019 Annual IRP Update
DSM	Cascade will examine how carbon tax scenarios impact which energy conservation measures are undertaken with ETO.	Ongoing, for inclusion in 2020 IRP
Avoided Cost	Investigate incorporating distribution system costs into the avoided cost calculation.	Beginning in 2018 for inclusion in 2020 IRP
IRP Process	Active participation in regional LDC IRP processes.	Beginning in 2017 for inclusion in 2020 IRP

SECTION 2

COMPANY OVERVIEW

Company Overview

> **Key Points**
> - Cascade serves diverse geographical territories across Washington and Oregon.
> - Cascade's primary pipelines are Northwest Pipeline (NWP), Gas Transmission Northwest (GTN), and Enbridge, formerly known as Westcoast (WCT), with access to three other pipelines.
> - Core customers represent 23% of total throughput, while non-core customers represent 77% of total throughput.
> - Cascade is a subsidiary of MDU Resources Inc., based in Bismarck, North Dakota.

Cascade Natural Gas Corporation has a rich history that began 65 years ago when business leaders and public officials in the Pacific Northwest initiated a campaign to bring natural gas to the region to replace other more expensive fuels. In 1953, five small utilities serving fifteen communities merged to form Cascade Natural Gas Corporation (CNGC or Cascade or Company). Over the years, Cascade continued to grow, merging with and purchasing other utility providers. The Company stock first traded on the New York Stock Exchange in 1973. In 2007, Cascade merged with Montana Dakota Utilities (MDU) Resources Group Inc. which is headquartered in Bismarck, North Dakota. Cascade's headquarters moved from Seattle, Washington, to Kennewick, Washington, in 2010.

Today, Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a diverse economic base as well as varying climatological areas. Cascade delivers natural gas service to more than 282,000 customers with approximately 70,000 customers in Oregon and 212,000 customers in Washington. The Company's customers reside in 96 communities--28 in Oregon and 68 in Washington. Cascade's service area consists of smaller, rural communities in central and eastern Oregon as well as western and central Washington.

The climate of the service territory is almost as diverse as its geographical extension. The western Washington portion of the service territory, nicknamed the I-5 corridor, has a marine climate with occasionally significant snow events. In general, the climate in the western part of the service territory is mild with frequent cloud cover, winter rain, and warm summers. Cascade's eastern Washington service territory has a semi-arid climate with periods of arctic cold in the winter and heat waves in the summer.[1]

Below are some of the more populated towns within the regions Cascade provides distribution service.

- **Northwest** – Bellingham, Mt. Vernon, Oak Harbor/Anacortes, the Kitsap Peninsula, the Grays Harbor area and Kelso/Longview;

[1]Western Regional Climate Center, https://wrcc.dri.edu/Climate/narrative_wa.php, retrieved September 28, 2017.

- **Central** – Sunnyside, Wenatchee/Moses Lake, Tri-Cities, Walla Walla and Yakima areas;
- **Southern** – Bend and surrounding communities, Ontario, Baker City and the Pendleton/Hermiston areas.

A map of Cascade's certificated service territory is provided as Figure 11-13 in Section 11, Glossary and Maps.

Pipeline and Basin Locations

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system using three natural gas pipeline companies. Northwest Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta gas, and Enbridge (WCT) provides British Columbia gas directly into the Company's distribution system. Cascade also holds upstream transportation contracts on TransCanada Pipeline's Foothills Pipeline (formerly ANG), NOVA Gas Transmission Ltd. (also known as NGTL), and Ruby Pipeline. More information about the pipelines and the supply basins is found in Section 4, Supply Side Resources. Maps of select pipelines are found in Section 11, Glossary and Maps.

Core vs Non-Core Service

Cascade offers all its customers core service which is the provision of gas supply which has been transported to Cascade's citygate and which Cascade then delivers over its distribution system to the end-use customer. Although Cascade offers core service to all its customers, not all of them take advantage of this type of firm service.

In 1989, concurrent with the passage of the Natural Gas Wellhead Decontrol Act, Cascade began allowing its large volume customers to purchase their own gas supplies and gas transportation services upstream of Cascade's distribution system. These customers, referred to as large volume transportation or non-core customers, procure from Cascade the distribution of their gas supply from citygate to the point of delivery at the customer's site. The Company currently has approximately 240 large volume customers who have elected non-core service.

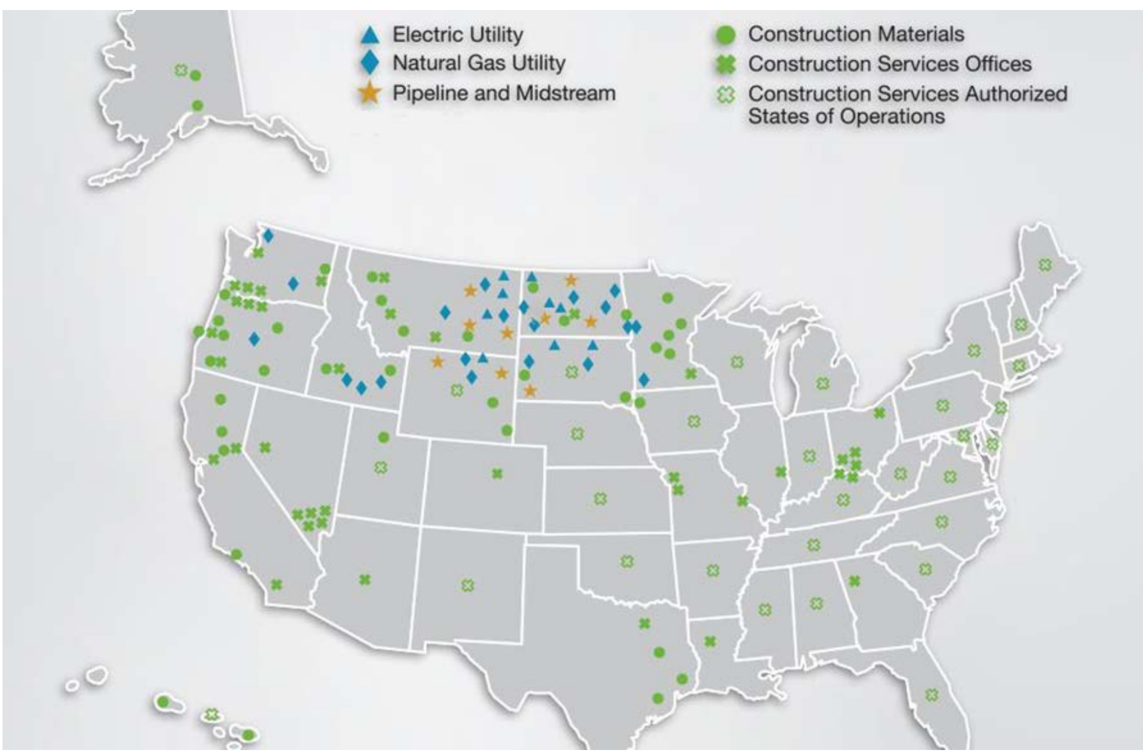
Since the Company does not provide gas supply and upstream pipeline transportation capacity resources to non-core customers, the Company does not plan for non-core customers in the resource analysis of its Integrated Resource Plan (IRP). Non-core demand is a consideration in distribution planning. While it is not the core substance of the IRP, it is included in Section 8, Distribution System Planning.
As of third quarter 2017, Cascade's residential customers represented approximately 12% of the total natural gas delivered on Cascade's system, while commercial

customers represented approximately 9% and the 500 core industrial customers consumed approximately 2% of total gas throughput. The remaining non-core industrial customers represented about 77% of total throughput.

Company Organization

In 2007, Cascade became a subsidiary of MDU Resources Group, Inc., a multidimensional regulated energy delivery and construction materials and services business, operating in 48 states and traded on the New York Stock Exchange under the symbol MDU. Cascade, with headquarters in Kennewick, Washington, is part of its utility group of subsidiaries. MDU Resources Group's utility companies serve more than one million customers. Cascade distributes natural gas in Oregon and Washington. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Figure 2-1 provides a geographical representation of the various services/territories served by MDU Resources.

Figure 2-1: MDU Resources Services and Territory



Company Headquarters

Figure 2-2 is a picture of the Company's headquarters, which is in Kennewick, Washington.

Figure 2-2: Cascade's headquarters in Kennewick, Washington

SECTION 3

DEMAND FORECAST

Overview

Each year Cascade develops a 20-year forecast of customers, therm sales, and peak requirements for use in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes. This forecast is a robust portfolio of estimates created by enhancing a single best-estimate forecast with various potential economic, demographic, and marketplace eventualities into low, medium, and high growth forecast scenarios. The scenarios are used for distribution system enhancement planning and as inputs in optimization models to determine the least cost portfolio of supply and DSM resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Key Points

- Cascade initiates its forecast with analyses of demand area, weather, and heating degree days (HDDs).
- Three peak day scenarios are examined: Average peak HDDs,
  System-wide max peak HDDs, and Max citygate peak HDDs.
- Cascade uses a 60 °F reference temperature to calculate HDDs.
- The Company utilizes an ARIMA modeling technique for customer and annual demand forecasts.
- High and low scenarios were included and alternative forecasting methodologies were considered.
- Cascade expects system load growth to be 1.58% per year or 34.6% over the 20-year planning horizon.
- A short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 was determined for price elasticity.
- Uncertainties in the future may cause differences from the Company's forecast.

Demand Areas

For 2018, Cascade forecasted at the citygate level. This is a change of methodology from previous years where certain models were built from the district or zonal level. Cascade has a total of 76 citygates of which only nine citygates feed non-core customers and the remaining 67 serve at least one core customer. Of the 67 citygates that serve core customers, eighteen are grouped into eight different citygate loops. Therefore, Cascade forecasts a total of 57 areas. Each citygate is assigned to a weather location. For this IRP, the Company assigned the citygates to either the closest weather location by distance or the closest weather location by climatic similarity. The citygate results are rolled up into zones and districts which segregate Cascade's system based on pipelines and weather (see Appendix B). Table 3-1 provides a cross reference for the demand areas.

Table 3-1: Demand Areas

Citygate	Loop	State	Weather Location	Zone
7TH DAY SCHOOL		WA	Yakima	10
A/M RENDERING		WA	Bellingham	30-W
ACME		WA	Bellingham	30-W

Citygate	Loop	State	Weather Location	Zone
ARLINGTON		WA	Bellingham	30-W
ATHENA		OR	Pendleton	ME-OR
BAKER		OR	Baker City	24
BELLINGHAM 1 (FERNDALE)	Sumas SPE Loop	WA	Bellingham	30-W
BEND	Bend Loop	OR	Redmond	GTN
BREMERTON (SHELTON)		WA	Bremerton	30-S
BURBANK HEIGHTS	Burbank Heights Loop	WA	Walla Walla	20
CASTLE ROCK		WA	Bremerton	26
CHEMULT		OR	Redmond	GTN
DEHAWN DAIRY		WA	Yakima	10
DEMING		WA	Bellingham	30-W
EAST STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
FINLEY		WA	Walla Walla	20
GILCHRIST		OR	Redmond	GTN
GRANDVIEW		WA	Yakima	10
HERMISTON		OR	Pendleton	ME-OR
HUNTINGTON		OR	Baker City	24
KALAMA #1		WA	Bremerton	26
KALAMA #2		WA	Bremerton	26
KENNEWICK	Kennewick Loop	WA	Walla Walla	20
LA PINE		OR	Redmond	GTN
LAWRENCE		WA	Bellingham	30-W
LDS CHURCH		WA	Bellingham	30-W
LONGVIEW-KELSO	Longview South Loop	WA	Bremerton	26
LYNDEN	Sumas SPE Loop	WA	Bellingham	30-W
MADRAS		OR	Redmond	GTN
MCCLEARY (ABERDEEN/HOQUIAM)		WA	Bremerton	30-S
MILTON-FREEWATER		OR	Walla Walla	ME-OR
MISSION TAP		OR	Pendleton	ME-OR
MOSES LAKE		WA	Yakima	20
MOUNT VERNON	Sedro-Woolley Loop	WA	Bellingham	30-W
MOXEE (BEAUCHENE)		WA	Yakima	11
NORTH BEND	Bend Loop	OR	Redmond	GTN
NORTH PASCO		WA	Walla Walla	20
NYSSA-ONTARIO		OR	Baker City	24
OAK HARBOR/STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
OTHELLO		WA	Walla Walla	20
PASCO	Burbank Heights Loop	WA	Walla Walla	20
PATTERSON		WA	Yakima	26
PENDLETON		OR	Pendleton	ME-OR

Citygate	Loop	State	Weather Location	Zone
PRINEVILLE		OR	Redmond	GTN
PRONGHORN		Redmond	Redmond	GTN
PROSSER		WA	Yakima	10
QUINCY		WA	Yakima	11
REDMOND		OR	Redmond	GTN
RICHLAND (Richland Y)	Kennewick Loop	WA	Walla Walla	20
SEDRO/WOOLLEY	Sedro-Woolley Loop	WA	Bellingham	30-W
SELAH	Yakima Loop	WA	Yakima	11
SOUTHRIDGE		WA	Walla Walla	20
SOUTH BEND	Bend Loop	OR	Redmond	GTN
SOUTH LONGVIEW	Longview South Loop	WA	Bremerton	26
STANFIELD		OR	Pendleton	GTN
STEARNS (SUNRIVER)		OR	Redmond	GTN
SUNNYSIDE		WA	Yakima	10
UMATILLA		OR	Pendleton	ME-OR
WALLA WALLA		WA	Walla Walla	ME-WA
WALLULA		WA	Walla Walla	ME-WA
WCT-CNG INTERCONNECT	Sumas SPE Loop	WA	Bellingham	30-W
WENATCHEE		WA	Yakima	11
WOODLAND		WA	Bremerton	26
YAKIMA CHIEF RANCH		WA	Yakima	10
YAKIMA TRAINING CENTER		WA	Yakima	11
YAKIMA/UNION GAP	Yakima Loop	WA	Yakima	11
ZILLAH (TOPPENISH)		WA	Yakima	10

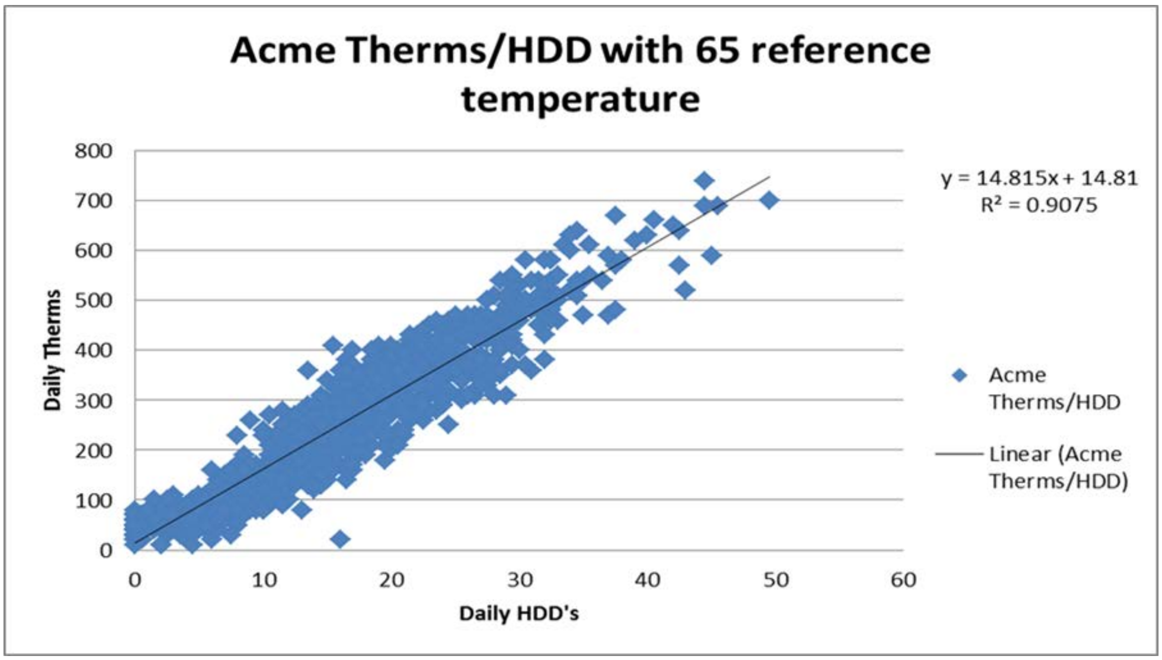
Weather

Historical weather data is provided by a contractor, Schneider Electric. The current forecast uses 30 years of recent history as the normal or expected weather. The forecast model takes the 30 previous years, converts the data to heating degree days (HDDs), then averages the HDDs into average days to create a normal or expected year. Cascade has seven weather locations with four located in Washington and three in Oregon. The three weather locations in Oregon are Baker City, Pendleton, and Redmond.

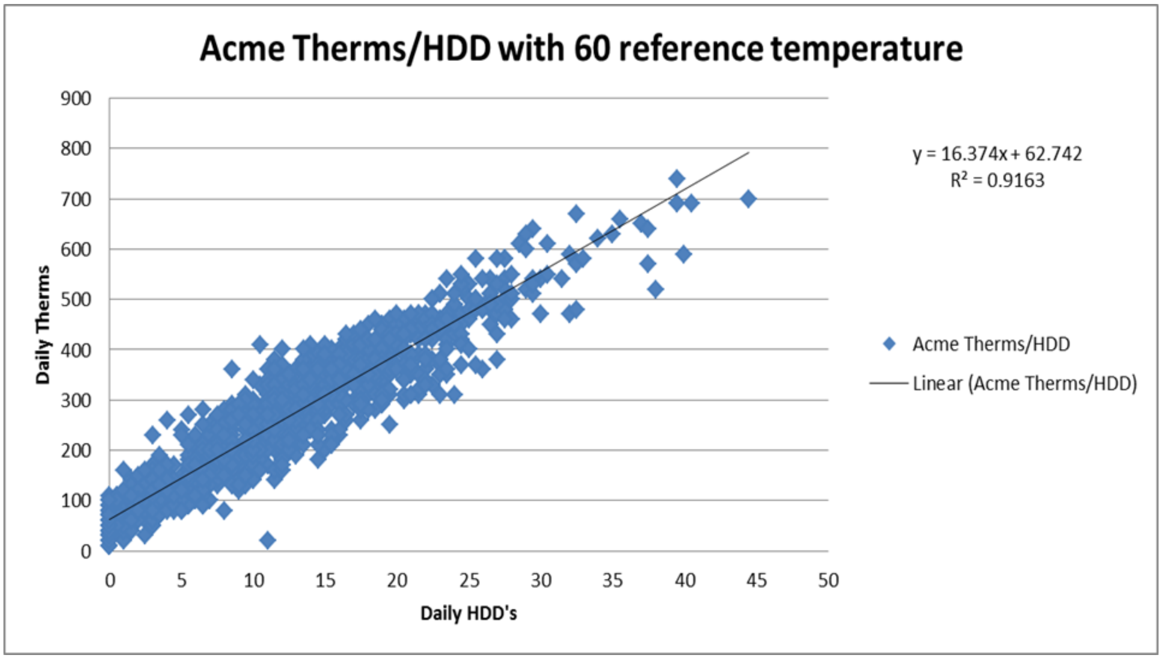
Heating Degree Days

HDD values are calculated with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 60 °F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to significantly rise. The historical threshold for calculating HDD has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces more accurate results. Graphs 3-1 and 3-2 illustrate why the lower threshold is preferable. These graphs show that heating demand does not begin to increase significantly until an HDD of five (65 °F minus 60 °F) is reached, if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold improves the R^2, thus giving a better measure of the relation between HDD and therms (measurement of heat usage). Cascade ran a backcast to compare the forecast with actual weather and customer counts in the regressions (ex. 2011 customers, with 2011 weather, to backcast 2011). When comparing, using a 65 °F reference temperature, the backcast had a mean absolute percentage error (MAPE) of 14.9%. When using a 60 °F reference temperature, the MAPE improved to 7.62%.

Graph 3-1: Acme Therm/HDD with 65°F Reference Temperature



Graph 3-2: Acme Therm/HDD with 60°F Reference Temperature



Peak Day HDDs

In order to ensure satisfaction of core customer demand on the coldest days, Cascade develops three peak day usage forecasts in conjunction with annual base load forecasts. Peak day forecasts enable Cascade to make prudent distribution system and peak capacity planning decisions to fulfill its responsibility to provide heating under all but *force majeure* conditions, particularly as most space-heating customers will have no alternative heating source during the coldest days in the event gas does not flow.

The three scenarios that are analyzed in the forecast model:

- Average peak HDDs;
- System-wide max peak HDDs; and
- Max citygate peak HDDs.

These peak days will give Cascade three different outcomes with varying amounts of demand. Average peak HDDs are calculated based on the average of the coldest day for each of the last 30 years. Initially, the coldest system-weighted peak day is found for each year for the last 30 years. The actual HDD from each of the 30 peak days is averaged resulting in an average peak HDD for each weather location. The average peak HDDs methodology allows Gas Supply to plan for the expected peak event during a heating season.

System-wide max peak HDDs are determined by first selecting the system-wide single coldest day recorded in the past 30 years. To determine the system-wide single coldest day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations. The weights are determined by the increase in demand experienced with an increase in one HDD. Cascade has found December 21, 1990, to be the highest, system-weighted HDD, at 56 HDDs for this period.

The max citygate peak HDDs are determined by finding the coldest HDD for each weather station in the 30-year history and combining those in one day. The max citygate peak day is a hypothetical scenario where the coldest HDDs for each weather station happen all at once.

Peak day demand is then derived by applying the HDDs from one of the three peak day scenarios to the peak day forecast methodology for each citygate.

For SENDOUT®, Cascade uses the system-wide max peak HDDs method. Cascade applies the HDDs experienced on December 21, 1990, to each of the regressions in the forecast model. For example, all citygates associated with the Redmond weather station use the HDD for Redmond on December 21, 1990, and similarly for all the other weather stations and citygates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each citygate. Applying December 21, 1990, weather temperatures to today's forecast methodology gives Cascade an accurate representation of the demand the Company could expect to experience if this weather happened during the planning horizon.

Cascade will continue to investigate how the peak day standard affects the core demand load areas which are short of capacity. This investigation will include (but not be limited to) analysis of how other regional utilities look at peak day, discussions with the various weather services, and continued dialogue with Commission Staff and other interested parties.

Customer Growth

Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short- and long-term. Cascade uses population and employment growth data from Woods & Poole (W&P). W&P growth forecasts are provided at the county level. It should be noted that W&P forecasts are adjusted whereas the internal intelligence about a demand area indicates a significant difference from W&P regarding observed economic trends. Cascade utilizes ARIMA models for the customer forecast as well as the demand forecast, which will be discussed in the next section. Below is the formula the Company used to run the regressions:

$$C_{Class}^{CG} = \alpha_0 + \alpha_1 Pop^{CG} + \alpha_2 Emp^{CG} + \alpha_m I_m + ARIMA\epsilon(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class$
- $Pop^{CG} = Population\ by\ Citygate$
- $Emp^{CG} = Employment\ by\ Citygate$
- $m = month$
- $I =$ $Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$
- $ARIMA\epsilon(p,d,q) =$ $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model for each of its 24 counties by customer class. First, the Company checks for stationarity. If the data is non-stationary Cascade differences the data, repeating the step until the data is stationary. Most times, the Company does not difference the data or would difference it only once. Once the differencing is determined, Cascade runs the regression and checks for autocorrelation. Cascade uses the Autocorrelation Function (ACF) and Partial Autocorrelation Function (PACF) to determine moving average or autoregressive terms for the model. Cascade then removes non-significant variables. Typically, the model only chooses one of the two between Population and Employment. The Company noticed that if a non-significant, monthly indicator variable was removed, the model often provides less robust results; therefore, for this IRP, some monthly indicator variables were left in even when non-significant. Cascade used Akaike Information Criterion (AIC) and Mean Absolute Percentage Error (MAPE), along with other statistics, in determining which model to use. Once the customer forecast is finished, the Company allocates the customers to each citygate within the county.

Customer count and therm forecasts are augmented by revisions to the base data and output to create a portfolio of potential scenarios. Low and high growth scenarios are created from the 95% confidence intervals from the forecast model. These scenarios, along with the original, best-estimate, expected scenario encapsulate a range of most-likely possibilities given known data. The most recent W & P data indicates an average growth of 1.54% between 2018 and 2037 for Cascade's service territory. The projected customer growth is provided in Appendix B. Based on historical experience and given expected weather, Cascade expects system load will likely remain within a range bound by the low and high growth scenarios.

Among other reasons, the Company believes that growth in the following regions will be a major factor in any forecasted system-wide deficiency:

- Bend, Oregon – The city of Bend recently approved an urban growth plan that is projected to allow for the development of 2,380 acres of land. City planners project this will add more than 17,000 homes and 21,000 jobs. No specific timeline for the completion of this expansion is provided in their May 2016 project update. On June 7, 2017, the city of Bend and Deschutes County adopted a joint management agreement to define responsibilities within the urban growth plan.[1]
- Walla Walla, Washington – The city of Walla Walla is heavily focused on promoting small business growth, tourism, and its reputation as a leading wine producer in a competitive, eastern Washington, wine market. Cascade currently projects growth of approximately 30% in this area over the 20-year planning horizon.[2]
- Tri-Cities, Washington – Richland, Kennewick, and Pasco have been a hotbed for growth in recent years. As of the most recent census numbers, population grew by 10% in the past four years. Furthermore, Pasco is currently in the top ten cities for population growth in Washington State. Cascade currently projects growth of over 35% in this area over the 20-year planning horizon.[3]

Annual Usage Forecast Methodology

As previously mentioned, Cascade utilizes ARIMA models for the demand forecast as well. Below is the model used for the demand forecast:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG} + \alpha_m I_m + \alpha_w I_w + ARIMA\epsilon(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} =$ $Heating\ Degree\ Days\ assigned\ to\ Citygate\ from\ Weather\ Location$
- $m = month$
- $w = weekend$
- $I =$ $Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$
- $ARIMA\epsilon(p,d,q) =$ $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms$

[1] *See* City of Bend Urban Growth Boundary Project Update, issued June 2017
[2] *See* http://www.wallawallatrends.ewu.edu/, updated October 2017
[3] *See* http://www.tri-cityherald.com/news/local/article32225670.html, issue May 2015

Cascade runs this model for each of the 55 citygates and citygate loops by customer class where applicable. Cascade starts with the above model for Residential, Commercial, and Industrial but each model is slightly different depending on which variables are significant. Cascade runs the regression and checks for autocorrelation. Cascade used the Autocorrelation Function (ACF) and Partial Autocorrelation Function (PACF) to determine moving average or autoregressive terms for the model. Cascade then removes non-significant variables. As with the customer forecast, Cascade used AIC and MAPE among others where statistics were used in determining which model to use.

Cascade developed the Use per Customer (UPC) coefficient by gathering historical pipeline demand data by day. The pipeline demand data includes core and non-core usage. The non-core data is backed out using Cascade's measurement data stored in the Company's Aligne energy transaction system which leaves daily core usage data. The daily data is then allocated to a rate schedule for each citygate by using Cascade's Customer Care and Billing System (CC&B). This data is then divided by number of customers to come up with a UPC number for each day and for each rate schedule at each citygate. The ARIMA regression model is then run using the UPC and HDD actuals to derive results.

Peak Day Forecast Methodology

The Company took the 3rd quartile of coldest days to analyze for peak day. Cascade removed the effect of warm weather on usage. After the data was parsed, Cascade ran linear regressions on the data with monthly indicators. The following formula is used for peak day forecasting:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG} + \alpha_m I_m$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} =$ $Heating\ Degree\ Days\ assigned\ to\ Citygate\ from\ Weather\ Location.$
- $m = month$
- $I =$ $Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$

Cascade runs this model for each of the 55 citygates and citygate loops by customer class where applicable. The Company runs the model and removes non-significant variables. Similar to the customer and demand forecast, Cascade used AIC and MAPE, among other statistics, in determining which model to use. Once the models are finalized Cascade analyzes peak day using three different HDD scenarios:

Average, System max, and Citygate max. As mentioned previously, the average peak day methodology uses the average HDD experienced on the coldest days in each of the past 30 years as an HDD for each weather location. System max peak day uses the coldest system-wide peak day experienced in the 30-year history (December 21, 1990). Citygate max finds the coldest day in the past 30 years and creates a hypothetical day where all weather locations experience those HDDs in the same day.

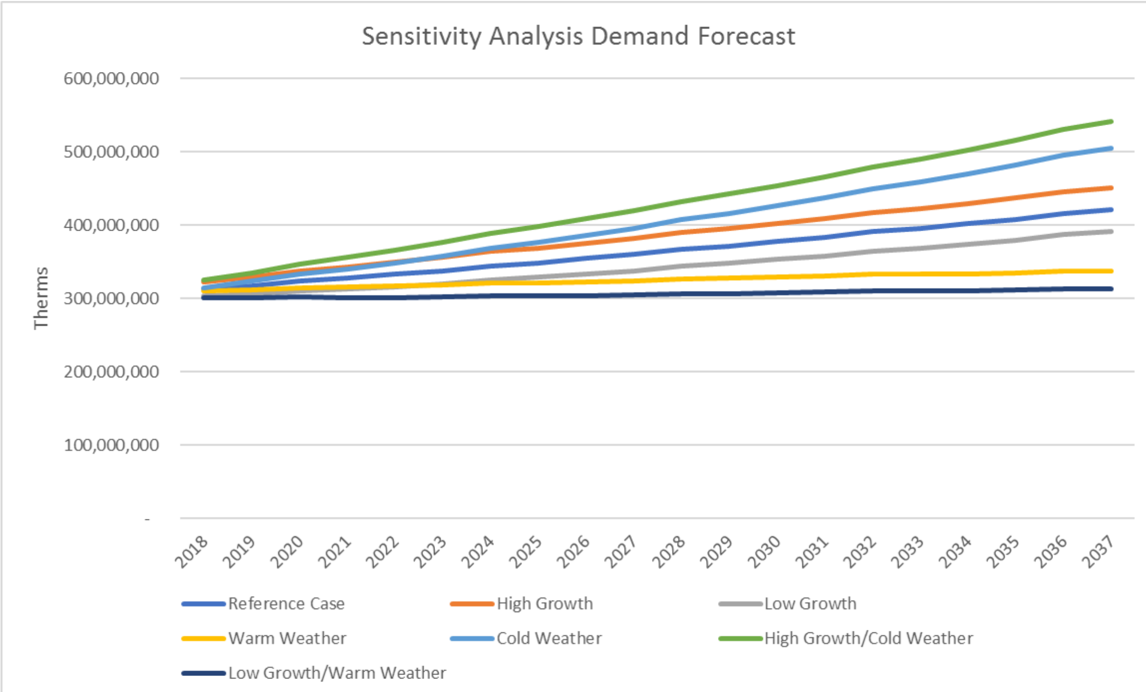
Sensitivity Analysis

Cascade stress tests the system in SENDOUT® by using alternative forecasting methodologies. These alternative forecasting methodologies refer to changing factors that influence demand. Alternative models include high and low customer growth, high and low weather patterns, or a combination thereof. The combination between alternative growth and weather results in high growth/cold weather, and low growth/warm weather because these test the extremes as they have a complementary effect on demand. Table 3-2 identifies the list of scenarios. Figure 3-1 charts the sensitivity analysis over the planning horizon.

Table 3-2: Growth Scenarios

Scenario	Weather	Growth	Use per Customer
Reference Case	Expected	Expected	Expected
Expected Scenario	Expected with peak event	Expected	Expected
High Growth	Expected	High	Expected
Low Growth	Expected	Low	Expected
Warm Weather	Low HDDs	Expected	Expected
Cold Weather	High HDDs	Expected	Expected
High Growth/ Cold Weather	High HDDs	High	Expected
Low Growth/ Warm Weather	Low HDDs	Low	Expected

Figure 3-1: Sensitivity Analysis Demand Forecast (Volumes in Therms)



The reference case contains expected weather, customer growth, and use per customer. The expected scenario is the same as the reference case with a single, system-wide, max peak day event. Expected weather is the average weather over the past 30 years. For high/low HDDs Cascade used the average temperature of the six coldest/warmest years to create a high and low weather scenario. Cascade believes six years is a sufficient timeframe to capture a realistic high/low scenario. Cascade applies the growth rates gathered from W&P as mentioned on pages 3-7 and 3-8, for the expected growth case. Cascade uses the expected regression results, as explained on page 3-8, at each citygate for all cases. High and low growth scenarios, discussed more on page 3-16, explain that Cascade uses the 95% confidence intervals from the customer forecast model. These sensitivity analysis tests on demand are only to show how weather and growth can impact demand over the 20-year planning horizon. Cascade performs a deeper sensitivity analysis by analyzing Monte Carlo runs in SENDOUT®. Monte Carlo analysis is discussed further in Section 7.

Forecast Results

Load growth across Cascade's system through 2037 is expected to fluctuate between 1.50% and 1.65% annually after smoothing the leap year anomaly. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at a rate near

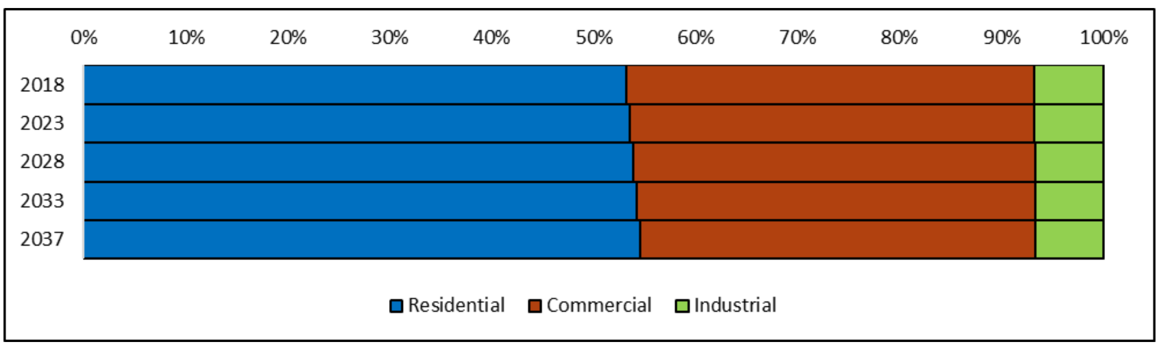
1.4-1.6% annually, while industrial expects a growth rate of around 1.9%. Table 3-3 shows the percentage of core growth by class over the planning horizon.

Table 3-3: Expected Load Growth by Class

	Residential	Commercial	Industrial	System
2018 - 2022	1.65%	1.36%	1.96%	1.56%
2023 - 2027	1.68%	1.39%	2.04%	1.59%
2028 - 2032	1.69%	1.42%	1.99%	1.61%
2033 - 2037	1.67%	1.40%	1.53%	1.55%
2018 - 2037	1.67%	1.39%	1.88%	1.58%

In absolute numbers, system load under normal weather conditions is expected to exceed over 417 million therms in 2037. A majority of core load today is residential. Cascade projects the ratio between residential, commercial, and industrial to increase in favor of residential customers. Residential customers are expected to grow from 53.1% of the total core load to 54.1% of the total core load by 2037. Figure 3-2 displays the relative percentage relationship of expected loads by class.

Figure 3-2: Expected Load Growth by Class



Cascade expects residential customers to increase their load by about 60 million therms and commercial core customers to increase load by approximately 37 million therms each over the 20-year planning horizon. Industrial customers are expected to increase load by approximately 9 million therms over the same period. Cascade expects load to increase about 108 million therms. Table 3-4 displays the expected core load volumes by class.

Table 3-4: Expected Load Growth by Class (Volumes in Therms)

	Residential	Commercial	Industrial
2018	165,986,093	124,425,988	22,244,749
2023	180,205,957	133,122,105	24,543,456
2028	196,701,735	143,177,871	27,156,720
2033	212,956,543	152,936,540	29,800,958
2037	227,524,569	161,690,705	31,663,120
2018 - 2037	37.07%	29.95%	42.34%

Load growth is primarily a result of increased customer counts. The number of commercial and industrial customers is expected to increase slightly faster than therm usage. Table 3-5 displays the expected customer counts by class.

Table 3-5: Expected Customer Counts by Class

	Residential	Commercial	Industrial
2018	249,170	36,236	624
2023	270,452	38,803	703
2028	293,930	41,606	784
2033	319,503	44,621	870
2037	341,318	47,171	935
2018 - 2037	25.67%	30.18%	49.81%

Geography

Load across Cascade's two-state service territory is expected to increase 34.6% over the planning horizon, with the Oregon portion outpacing Washington at 41.6% versus 32.2%. Table 3-6 shows the expected core load volumes by state.

Table 3-6: Expected Load by State (Volumes in Therms)

	Washington	Oregon	System
2018	232,832,110	79,824,720	312,656,830
2023	249,909,757	87,961,761	337,871,517
2028	269,997,677	97,038,648	367,036,325
2033	289,983,412	105,710,630	395,694,041
2037	307,810,669	113,067,725	420,878,394

Within Oregon, the central part of the state is expected to see a large increase in growth. The expected growth around the Bend/Redmond area is the cause of the high growth percentage at Redmond weather location. Table 3-7 shows the percentage growth of load by each of Cascade's weather locations. Table 3-8 shows the percentage growth of load by each pipeline zone over the planning horizon. Lastly, Table 3-9 displays a range of core peak day growth over the planning horizon along with a sampling of peak day therms. Peak Day growth is expected to grow approximately 1.58%, similar to annual growth rate.

Table 3-7: Oregon 20-Year Load Growth by Weather Location

Redmond	45.7%
Pendleton	34.6%
Baker City	28.9%
Oregon	41.6%

Table 3-8: System 20-Year Load Growth by Pipeline Zone

Zone 10	30.3%
Zone 11	24.0%
Zone 20	51.5%
Zone 24	28.9%
Zone 26	33.4%
Zone 30-S	26.0%
Zone 30-W	32.7%
Zone GTN	45.7%
Zone ME-OR	34.6%
Zone ME-WA	22.7%

Table 3-9: Expected Peak Day Growth (Volumes in Therms)

Period	Peak Growth	Year	Peak Day Therms
2018 – 2022	1.58%	2022	3,529,692
2023 – 2027	1.61%	2027	3,822,168
2028 – 2032	1.61%	2032	4,140,271
2033 – 2037	1.56%	2037	4,476,347

High and Low Scenarios

High and low scenarios were created by examining the 95% confidence intervals resulting from the customer forecast model. Cascade is expecting about 1.58% in customer growth on the expected case, 1.36% on the low band and 1.78% on the high band. Table 3-10 displays the expected total system load growth across various scenarios.

Table 3-10: Expected Total System Load Growth (By Percentage) Across Scenarios

	Low	Mid	High
2018 - 2022	1.08%	1.56%	2.01%
2023 - 2027	1.36%	1.59%	1.80%
2028 - 2032	1.48%	1.61%	1.71%
2033 - 2037	1.49%	1.55%	1.62%
2018 - 2037	1.36%	1.58%	1.78%

Load growth under poor economic conditions is expected to be around 1.3% annually over the forecast period, while load growth under good economic conditions is expected to be around 1.8% annually. The cumulative effect of high growth over 20 years could result in an additional load of 30 million therms, while low growth could result in a load with 29.5 million therms less than predicted in the medium growth scenario. Table 3-11 shows the expected total system load across these scenarios.

Table 3-11: Expected Total System Load Growth Across Scenarios (Volumes in Therms)

	Low	Mid	High
2018	302,971,151	312,656,830	322,441,944
2023	320,188,306	337,871,517	355,643,185
2028	344,101,735	367,036,325	390,131,910
2033	368,750,520	395,694,041	422,706,108
2037	391,276,263	420,878,394	450,698,833
Deviation	(29,602,131)		29,820,439

Price Elasticity

Price elasticity is an economic concept which recognizes that customer consumption changes as prices rise or fall. The amount of this change or elasticity is a function of other available products (i.e., substitutes) or the ability for customers to go without or use less with no meaningful impact on their personal life or in commerce.[4,5] Price signals describes how customers see or expect future pricing to affect them.[6]

Price elasticity is expressed mathematically as a coefficient describing the amount of change in consumption per change in price. For example, a price elasticity factor of -0.10 means a consumer will reduce usage by 1% if the price increases by 10%. Conversely, a 0.10 coefficient factor for a 10% price decrease would predict customers would increase consumption by 1%. For products with high substitutability, the coefficient factors are high (e.g., greater than 0.50) and vice versa.

Price elasticity can be highly temporal. Consumers may not be able to make changes with short-term price increases or decreases. Yet, several years out, that same customer may replace equipment or make behavioral changes to use significantly less or more of a product depending on whether, over the long term, the product is more or less expensive.

The importance of price elasticity to natural gas integrated resource planning lies in the 20-year period over which the demand forecasts are estimated. This forecast (or range of forecasts under scenario planning) is a key determinant of the avoided cost. Low price elasticity in a rising natural gas price environment would suggest forecasted higher load would not change customer behavior and more natural gas would need to be acquired with corresponding delivery infrastructure. However, if usage materially decreases with higher prices, then fewer purchases and less capital investment by an LDC would be necessary. Therefore, price elasticity has some effect on the avoided cost.

Because avoided costs are integral to conservation planning, among other components, the impact of price elasticity on consumer consumption is of interest to all stakeholders in the planning process.

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[4] An example of substitutes for a commodity is transportation fuels. As gasoline prices rise, commuters may carpool more or use public transportation. Conversely, in a low-cost gasoline environment, people may take longer driving vacations rather than fly or stay closer to home. In the long-term, higher gasoline prices could steer customers to changing out their choice of their automobiles toward electric vehicles or compressed natural gas (CNG) vehicles, thereby reducing their gasoline consumption to zero. Conversely, some drivers such as taxi cab owners may have no near-term choices regarding the number of miles driven; rather, they pass the higher cost of gasoline to their customers.

[5] The decision to go to the movies is an example where going without or using less is observed as prices increase. Many entertainment alternatives are present, including waiting until a certain film is released to DVD or Blu-ray.

[6] "A price signal is information conveyed to consumers and producers, via the price charged for a product or service, which provides a signal to increase/decrease supply and/or that the demand for the priced item has increased/decreased." *See* https://en.wikipedia.org/wiki/Price_elasticity_of_demand , as of October 26, 2017.

Several attributes of the regulated utility environment cause price elasticity calculations to be difficult to calculate with precision. Within customer classes, the type of customer usage varies:

- Residential—heating and non-heating
- Commercial—heating and processing

Additionally, regulatory protocols may reduce direct signals because the annual purchased gas adjustment (PGA) may result in price increases or decreases of unknown magnitude. Further, customers assume general rate cases and price changes will occur annually or biannually. As a result, customers are more likely to be uncertain of future pricing than to have the preconception that prices will rise.

Several items reduce load growth over time, regardless of price elasticity and price signals. Changes in economic conditions, added conservation, revised building codes and appliance standards, and advances in technology lead to reduction in usage irrespective of pricing. This makes it difficult for customers to react to meaningful price signals and difficult for utilities to isolate primary factors for long-supply term price elasticity calculations (other than inflation). Regardless, customers may not return (or rebound) to historic usage after experiencing higher or lower price excursions.

A review of price elasticity leads to the following findings relevant to Cascade's current IRP process:

- Price elasticity exists, yet determining specific coefficient factors for linear modeling is inexact;
- A range of coefficient factors should be used to test sensitivities of the factors and impacts to the forecasts;
- Given Cascade's diverse geographical territory, the statistical significance of price elasticity coefficients is uncertain;
- Several complicating factors call into question the accuracy and application of price elasticities. These include:
    - Regulatory mechanisms (e.g., PGAs and general rate cases) which dampen price signals or information to customers about future pricing;
    - Historical data (embedded with effects of conservation, technology advances, and changing economic conditions) renders reliance on this data imperfect for precise price elasticity determination;
- The retail price of the most substitutable fuel—electricity—moves with the cost of natural gas, thereby lessening the economic value of alternative fuels to customers; and
- Evolution of modeling suggests that future IRP modeling should incorporate iterative quantitative equations to allow built-in price elasticity effects.

Regardless, the Company believes price elasticity must be considered. For Cascade's 2018 IRP, a short-run coefficient factor of -0.10 and a long-run factor of -0.12 with ranges of plus or minus 0.07 is justifiable given regional studies and other utilities' modeling efforts. Several price elasticity inquiries are traditionally referenced in regional price elasticity discussions. These include:

- The American Gas Association (AGA) released a study in 2007 identifying the short-run price elasticity coefficients for the Pacific and Mountain regions to each be -0.07 with a low and high range of -0.03 and -0.13 respectively. The long-run estimates were -0.12 (Pacific) and -0.10 (Mountain), with the range being between -0.01 and -0.29.[7]

- The geographic area of a utility's service territory can result in the statistical significance of price becoming more uncertain. This suggests that for Cascade—with its customers spread over two states in smaller sections—relatively precise price elasticity coefficient factors would either not be available or would be costly to determine with lesser benefits of doing so.[8]

- Use per customer has been decreasing over the past 30 years prompted by multiple factors, including systemic items such as conservation, building codes, and appliance standards and behavioral influences such as the 2008 recession.

A review of these studies and inquiries of price elasticity in the natural gas industry indicates no regional precise calculations are available specific to a utility. A short-run coefficient factor of -0.10 and a long-run factor of -0.12 recognizes the temperature differentials of its service territory, east and west of the Cascade Mountains with low and high ranges at plus or minus 0.07.

Alternative Forecasting Methodologies

Cascade has made a slight change to the forecast methodology this year by using customers in the coefficient for the demand forecast formula. Cascade purchased SAS Analytics, a statistical analysis software, and has modeled ARIMA forecast methodologies. The Company plans to continue improving the customer and demand forecast model through SAS or other statistical software such as R.

The Company is responsive to several regulatory principles in forecasting. These include:

- A desire for precision and a high degree of accuracy;

[7] Joutz, Frederick and Robert P. Trost. An Economic Analysis of Consumer Response to Natural Gas Prices, Prepared for the American Gas Association, March, 2007. Available at http://standards.globalspec.com/std/1168989/aga-f62007.
[8] Bernstein, Mark A, and James Griffin. Regional Differences in the Price-Elasticity of Demand for Energy – RAND Corporation, 2005.

- A universal understanding that forecasts should mirror future realities but may have unanticipated swings in either direction;
- A disconnect between planning and operational functions, in that natural gas purchasing and dispatch will be based on immediate needs which, in actuality, are guaranteed to vary from the plan (per the previous bullet);
- An understanding that an increased cost of improved precision sometimes has decreasing customer benefits;
- A need to meet Regulators' expectation that the Company show continual improvement because new tools are available. For example, the concept of "adaptive management" can be applied;
- The major differences in accounting treatment between the states regarding test years for ratemaking purposes (that is, for general rate case filings) and not necessarily for planning. At this time, Oregon uses future test year accounting while Washington employs a historic test year;
- The fuzziness of historic data that includes effects of energy efficiency, retail price (from annual PGA—purchased gas adjustment—changes and other rate changes), sometimes abnormal weather, new technology, and then-unique economic conditions (e.g., recession, interest rates, etc.) Cascade uses actual historic data. The term fuzziness is used in the context of basing forecasts on past-period data that includes many variables, any one of which may have increased or decreased in the intervening time between historical occurrence and forecasted periods. This causes difficulty for utilities trying to isolate primary factors for greater precision of long-term calculations.
- Unknown and uncertain future changes such as the assumptions for CO_2 required for carbon policy and other environmental externalities; and
- A need to demonstrate support for assumptions such as growth in customers, use per customer and changes from previous forecasts, type of use (i.e., heating, manufacturing, etc.), to name a few.

This illustrates the complexity of forecasting and highlights areas of stakeholder attention. Best efforts at appropriate reasonable cost distill these factors into a generally-accepted forecast with recognition of inherent uncertainties.

Uncertainties

This forecast represents Cascade's best estimate about future events. At this time, several important factors make predicting future demand particularly difficult – economic recovery, carbon legislation, building code changes, direct use campaigns, conservation, and long-term weather patterns. The range of scenarios presented here encompasses the full range of possibilities through econometric analysis. These forecasts were created after running through a matrix of different functional forms and economic indicators. The chosen indicators were selected because of their consistency in returning statistically valid results. While they may be the best results mathematically, they are not the sole and only determinants of demand. As a result, while Cascade believes that the numbers presented here are accurate and that the scenarios presented represent the full range of possibilities, there are and always will be uncertainties in forecasting future periods.

SECTION 4

SUPPLY SIDE RESOURCES

Overview

Cascade's core market residential and small volume commercial and industrial customers expect and require the highest reliability of energy service. Because of the Company's obligation to provide gas service to these customers, the Company must determine and achieve the needed degrees of service reliability and attain it at the lowest cost possible while maintaining infrastructure that is sufficient for customer growth. Assuming such an infrastructure is operating effectively, the most important functions necessary for reliable natural gas service are planning for, providing, and administering the gas supply, interstate pipeline transportation capacity, and distribution service purchased by core market customers.

This section describes the various gas supply resources, storage delivery services from Jackson Prairie and Plymouth LNG service, and transportation resource options available to the Company as supply side resources.

Key Points

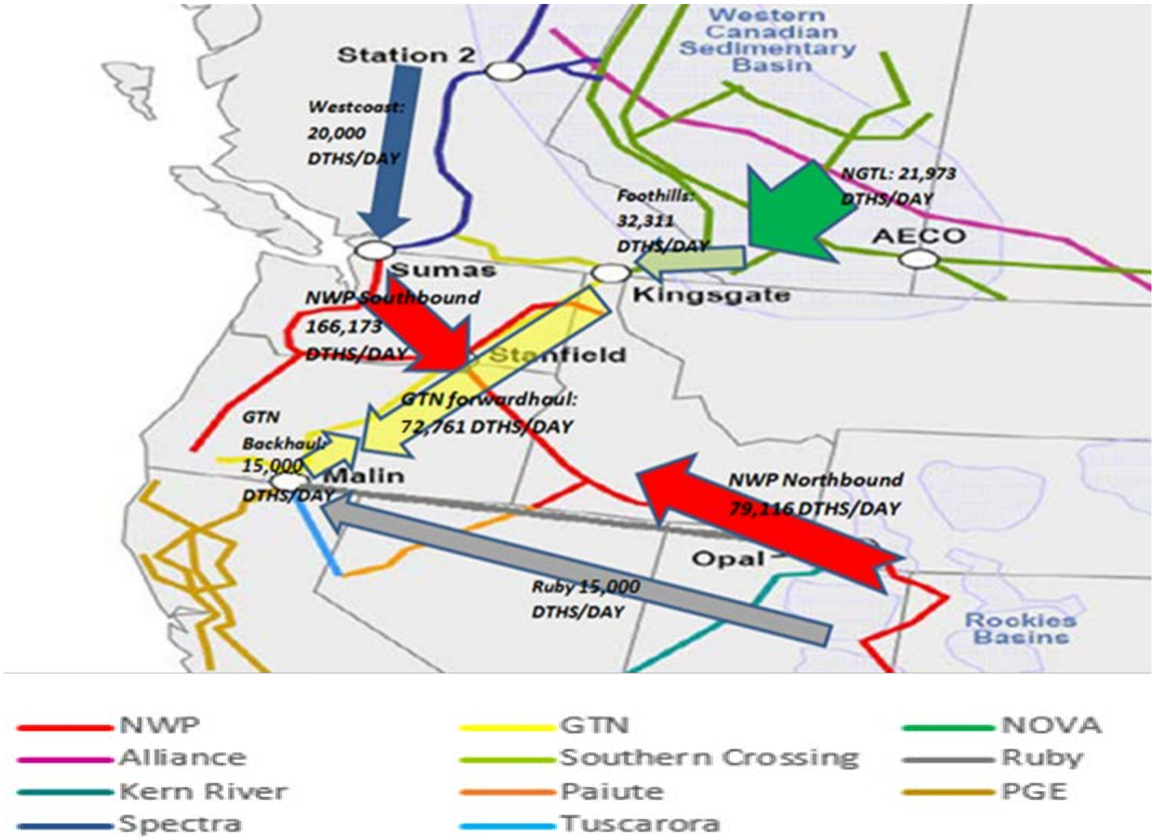
- To meet the Company's core market demand, Cascade accesses firm gas supplies and short-term gas supplies purchased on the open market, plus storage.
- Cascade purchases gas from the Rockies, British Columbia (Sumas), and Alberta (AECO). Gas is transported to the Company's system by either bundled or unbundled contracts.
- The long-term planning price forecast is based on a blend of futures market pricing along with long-term fundamental price forecasts from multiple sources.
- The Company identifies potential incremental supply resources for the 2018 IRP.
- Risk management policies are implemented to promote price stability.
- Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply purchasing strategy.
- Modeling of Cascade's available resources results in the lowest reasonably priced optimum portfolio.

Gas Supply Resources

Gas supply options available to Cascade to meet the core market demand requirements generally fall into two groups: 1) Firm gas supplies on a short- or long-term basis, and 2) Short-term gas supplies purchased on the open market as needed for a particular month for one or more days. A separate and important source of gas supply is natural gas storage service, which is required to provide economical service to low load factor customers during seasonal peak and the needle peaks of the heating season.

Cascade's gas supply portfolio is sourced from three basic areas of North America: British Columbia, Alberta, and the Rockies. Figure 4-1 provides a general overview of regional gas flows to Cascade's distribution system.[1] A larger map of Figure 4-1 is also provided in Section 11, Glossary and Maps, with Figure 11-12.

Figure 4-1: Regional Map Showing General Flow Paths for System Gas Supplies



Firm Supply Contracts

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except for during *force majeure* conditions. From Cascade's perspective, the most important consideration is the seller's contractual commitment to make gas available day in and day out regardless of market conditions. Firm supplies are a necessary component of Cascade's core market portfolio given its obligation to serve and the lack of easily obtainable alternatives for customers during periods of peak demand. Firm supply contracts can provide base load services, seasonal load increases during winter months, or they can be used to meet daily needle peaking requirements. Quantities vary, depending on the need and length of the contract. Operational considerations regarding available upstream pipeline transportation capacity and any known constraints must also be considered. Base load contracts can range from as small as 500 dths/day to quantities in excess of

[1] GTN forward haul reflects 10,000 dth/day acquired by Cascade on December 1st, 2017

10,000 dths/day. Blocks of 1,000, 2,500, 5,000 and 10,000 dths/day are standard as these are the most operationally and financially viable blocks for suppliers.

Base load supply resources are those that are typically taken day in and day out, usually 365 days a year. As a result, base load gas tends to be the least expensive of the firm supply contracts because it matches the production of gas and guarantees the producer that the volumes will be taken. The Company's ability to contract for base load supplies is limited because of the relatively low summer demand on Cascade's system. Base load resources are used to meet the non-weather sensitive portion of the core market requirements or may be used to refill storage reservoirs during periods of lower demand.

Winter gas supplies are firm gas supplies that are purchased for a short period during the winter months to cover increased loads, primarily for space heating. The contracts are typically three to five months in duration (primarily November through March). This enables the Company to ensure firm winter supplies without incurring obligations for high levels of *take* during periods of low demand in the summer months. Winter supplies combined with base load supplies are adequate to cover the moderately cold days in winter.

Peaking gas supplies, similar to storage, are firm contracts purchased only as load actually materializes due to high winter demand. That is, the seller must deliver the gas when the Company requires it, but the Company is not required to take gas unless it is needed to meet customer load requirements. Peaking resources typically allow the Company to take between fifteen and twenty days of service during the winter period. These resources are more expensive than base load or winter supplies and typically include fixed charges to cover the costs for the sellers to stand by to deliver the supplies.

Needle peaking resources are utilized during severe or arctic cold experiences when demand can increase sharply. These resources are very expensive and are available for a very short period of time. One source of needle peaking gas supply that is actually a form of demand side management may be obtained from Cascade's core interruptible customer base. These customers are required to maintain standby or alternate fuel capability so that Cascade can request the customer switch to its alternate fuel source so Cascade can utilize (divert) the gas supply and transportation capacity to meet the Company's core firm market requirements. The benefits associated with this type of resource would include lowering the demand of the industrial facility and providing a like amount of additional gas supply with pipeline capacity to meet core demand. Needle peaking requirements can also be met through the use of propane air plants or on-site liquefied natural gas (LNG) facilities. Currently, Cascade does not own or operate any LNG facilities along the distribution system.

A cost comparison between propane and natural gas can be done based on their individual BTU ratings. Assuming natural gas is priced at $6.00 per 1,000 cubic feet, that $6.00 would purchase approximately 1.03 million BTUs of energy. This would be equivalent to 11.26 gallons of propane. At $2.00/gallon of residential propane (as of October 2016), natural gas would be a more cost-effective energy solution under these conditions. Breaking it down even further, natural gas needs to be priced at more than $22.52 per 1,000 cubic feet for propane to be a more cost-effective energy solution (provided the cost for propane is $2.00/gallon).

Supply contract terms for firm commodity supplies vary greatly. Some contracts specify fixed prices, while others are based on indices that float from month to month. Some contracts have fixed reservation charges assessed each month, while others may have minimum daily or monthly take requirements. Most contain penalty provisions for failure to take the minimum supply according to the contract terms. Contract details will also vary from year to year depending on Company and supplier needs, and the general trends in the market.

Gas that is purchased for a short period of time (one to 30 days) when neither the seller nor the buyer has a longer-term firm commitment to deliver or take the gas is referred to as a spot market purchase. Spot market supplies differ from firm resources in that they are more volatile, both in terms of availability and price, and are largely influenced by the laws of supply and demand.

In general, spot market supplies (also called *day gas* or *just-in-time gas*) are provided from gas supplies not under any long-term firm contract. Therefore, as firm market demand decreases, more gas becomes available for the spot market. Prices for spot market supplies are market driven and may be either lower or higher than prices under firm supply contracts. In warmer weather, as firm market demand requirements decrease, usually more gas becomes available for the spot market, resulting in lower prices. In colder weather, as firm markets demand their gas supplies, the remaining spot market supplies can carry higher prices until the price equates or exceeds that of alternate energy supplies (such as oil or electricity). Spot supplies can be expected to move to the markets that offer the highest price, which in turn can affect delivery reliability.

Due to the potential for interruption of the spot market, these supplies are not considered a reliable source of gas supply for the winter peaking requirements of Cascade's core market. As identified earlier, part of the reason these supplies are considered less reliable is that these volumes are made available after longer-term firm commitments have been contracted for delivery by upstream suppliers. The available volumes are likely to vary daily, depending on production or the suppliers' ability to store un-marketed supply. Under a North American Energy Standards Board (NAESB) contract, parties can identify firm, variable, or interruptible quantities for these supplies. Buyers and sellers use this standard contract when entering into short-term supply transactions. Therefore, these spot volumes are more susceptible to daily operational constraints on the upstream pipelines. This is particularly true in the case of the Northwest Pipeline (NWP), which is a displacement pipeline with bi-directional flow. Depending on how gas is scheduled versus how it physically flows between compressor stations, constraints can possibly occur. This is further complicated because each of the pipelines has multiple supply scheduling deadlines, allowing scheduled volumes to be adjusted. As a result, at any given point in the process, constraints can occur, leading to the potential of the scheduled spot supply volumes being reduced or not delivered to the citygate at all.

The role for spot market gas supply in the core market portfolio is based upon economics. Spot market supplies may be used to supplement firm contracts during periods of high demand or to displace other volumes when it is cost-effective to do so. For example, should prices in one basin drop radically compared to another basin, a supply contract may allow the flexibility to reduce takes in order to take advantage of spot supply from a lower priced basin. Depending upon availability and price, spot market volumes may be used in place of storage withdrawal volumes to meet firm requirements on a given day or for mid-heating season refills of storage inventory during periods of moderate weather.

Storage Resources

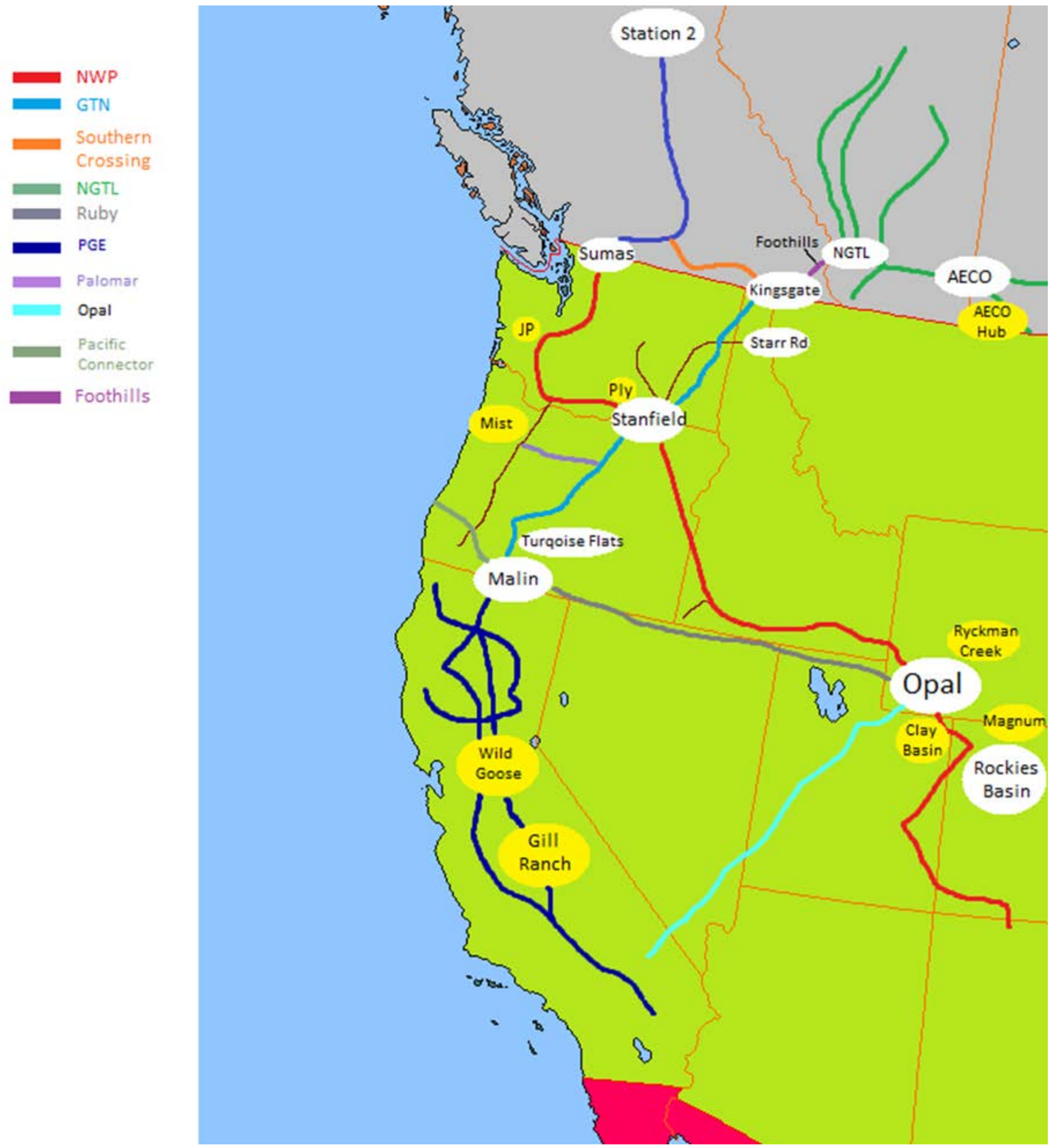
Cascade also utilizes natural gas storage to meet a portion of the requirements of its core market. Storing gas supplies, purchased and injected during periods of low demand, is a cost-effective way of meeting some of the peak requirements of Cascade's firm market. Natural gas can be stored in naturally occurring reservoirs, such as depleted oil or gas fields, salt caverns or other geological formations with an impermeable cap over a porous reservoir. Gas can also be stored in vessels or tanks under pressure as compressed natural gas or cooled to a liquid state, which is liquefied natural gas (LNG).

Natural gas storage service is not only an excellent supply source for meeting peak winter demand, but it can also be an important gas supply management tool. Storing excess or unused supply during periods of low demand increases the annual utilization rate of a supply contract, thereby improving the annual load factor for the Company's gas supplies. Improving the annual load factor of a supply contract improves the Company's ability to purchase gas supplies on a more economical basis. Purchasing natural gas for storage during periods of low demand generally yields prices at the low point on the seasonal price curve.

Depending upon the location of the storage facility, pipeline transportation may also be required to move the gas from the facility to the distribution system. Storage facilities located within the Company's distribution system or on the interstate pipeline are preferable to those located off-system. Off-system storage requires additional upstream pipeline transportation and may limit the flexibility of the resource.

Cascade does not own any storage facilities and, therefore, must contract with storage owners to lease a portion of those owners' unused storage capacity. Figure 4-2 displays the location of some of the storage facilities in the region.

Figure 4-2: Regional Map Showing Location of Various Gas Storage Facilities



Cascade has contracted for storage service directly from Northwest Pipeline since 1994. Jackson Prairie is located in Lewis County, Washington, approximately ten miles south of Chehalis. The following extract explaining the Jackson Prairie facility is found on Puget Sound Energy's website. Puget is one-third owner of the Jackson Prairie facility.

> Jackson Prairie is a series of deep underground reservoirs-basically thick porous sandstone deposits. The sand layers lie approximately 1,000 to 3,000 feet below the ground surface. Large compressors and pipelines are employed at JP to both inject and withdraw natural gas at 45 wells spread across the 3,200-acre facility. Currently it is estimated that Jackson Prairie can store nearly 25 BCF of working gas. The facility also includes "cushion" gas which provides pressure in the reservoir of approximately 48 BCF. In terms of withdrawal capability, the facility is capable of delivering 1.15 BCF of natural gas per day.[2]

The Company also has contracted for service from NWP's Plymouth, Washington LNG facility. Plymouth is located in Benton County, Washington approximately 30 miles south of Kennewick. According to NWP's website, the total facility has storage capacity of 2.4 BCF. Cascade has leased approximately 28% of this storage capacity.

Both Jackson Prairie facilities and the Plymouth facility are located directly on NWP's transmission system. Therefore, storage withdrawal rates can be changed several times during an individual gas day to accommodate weather driven changes in core customer requirements. This type of operating flexibility would not necessarily be available with off-system storage. Withdrawal capabilities must also be accompanied by firm capacity on the transporting pipeline(s) to be of any value as a reliable source of gas supply. Cascade's Jackson Prairie storage and Plymouth LNG service require TF-2 firm transportation service for storage withdrawals; Cascade has sufficient firm TF-2 service to meet its storage daily deliverability levels. The Company's contracted storage services are summarized in Table 4-1.

Table 4-1: Cascade Leased Storage Services (Volumes in Therms)

Facility	Storage Capacity	Withdrawal Rights
Jackson Prairie (Principle)	6,043,510	167,890
Jackson Prairie (Expansion)	3,500,000	300,000
Jackson Prairie (2012)	2,812,420	95,770
Plymouth LNG (Principle)	5,622,000	600,000
Plymouth LNG (2016)	1,000,000	181,250

[2] *See* https://pse.com/aboutpse/PseNewsroom/MediaKit/052_Jackson_Prairie.pdf, as of October 25, 2017.

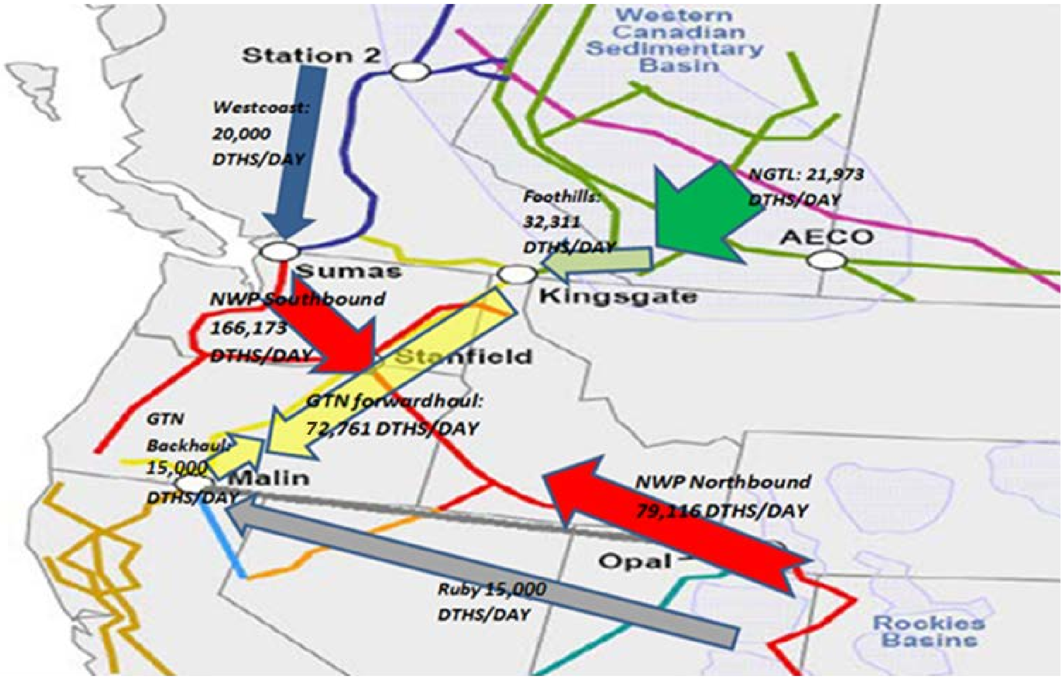
Capacity Resources

Capacity options are either interstate pipeline transportation resources or capacity on Cascade's local distribution system. Cascade's local distribution system is built to serve the entire connected load in its various distribution service areas on a coincidental demand basis, regardless of the type of service the customer may have been receiving.

Pipeline transportation resources are utilized to transport the gas supplies from the producer/supply sources to Cascade's system. Cascade currently purchases supplies from three different regions or basins: U.S. Rockies, British Columbia, and Alberta, Canada. Unless the supplier has bundled its sale of gas supplies with capacity (i.e. a citygate delivery), these resources require pipeline transportation to deliver them to Cascade's local distribution system. Transportation resources historically have been purchased from the pipeline at the time of an expansion under long-term (20 to 30 year) contracts.

Cascade has over 30 long-term annual contracts with NWP, numerous long-term annual and winter-only transportation contracts with GTN (including the upstream capacity on TransCanada Pipeline’s Foothills and Alberta systems), a long-term, winter-only contract with Ruby Pipeline, and one long-term annual contract with Enbridge (Westcoast Transmission) in British Columbia, Canada. These contracts do not include storage or other peaking services that may provide additional delivery capability rights ranging from nine to 120 days. Figure 4-3 provides a general flow of Cascade’s combined contracted pipeline transportation rights.

Figure 4-3: Regional Map Showing Current Contracted Pipeline Transportation Flow



A complete listing of Cascade's current transportation agreements is provided in Appendix E.

At a minimum, in order to ensure a diversified physical portfolio, the basic design of Cascade's transportation portfolio considers incorporating these general physical products or elements:

- Annual supply package;
- November through March (the whole heating season);
- December through February (peak of the heating season);
- Spring Seasonal (Apr-Jun);
- Spring/Summer Seasonal (April through October);
- Day Gas;
- On an annualized basis, supplies are typically secured as follows: 1/3 British Columbia, 1/3 Alberta and 1/3 Rockies; and
- No more than 25% of the overall portfolio can be supplied by a single party.

Natural Gas Price Forecast

For IRP purposes, the Company develops a baseline, high, and low natural gas price forecast. Demand, oil price volatility, the global economy, electric generation, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future.

Cascade considers price forecasts from several sources, such as Wood Mackenzie, Energy Information Administration (EIA), Bentek, NYMEX Henry Hub, Northwest Power and Conservation Council (NWPCC), as well as Cascade's own observations of the market to develop the low, base, and high price forecasts. For confidentiality purposes, the Company refers to the selected sources as Sources 1-4 when discussing how these sources are weighted in Cascade's Henry Hub forecast. The following discussion provides an overview of the development of the baseline forecasts.

Cascade's long-term planning price forecast is based on a blend of futures market pricing along with long-term fundamental price forecasts from multiple sources. Since pricing on the market is heavily influenced by Henry Hub prices, the Company closely monitors this market trend. While not a guarantee of where the market will ultimately finish, the futures market (NYMEX) is the most current information available that provides some direction as to future market prices. On a daily basis, Cascade can see where Henry Hub is trading and how the future basis differential in the Company's physical supply receiving areas (Sumas, AECO, Rockies) is trading.

Cascade believes that relying on a single source for developing the Company's 20-year price forecast is not the most reasonable approach. Some sources such as EIA and Wood Mackenzie produce Henry Hub pricing over the long-term; whereas other sources like the NYMEX basis (e.g., Sumas) provide price indicators over a shorter period of time. Additionally, price forecast sources produce their forecasts or indicators at varying points in time throughout the year. Finally, most forecasts are at an annual level vs a monthly level. In order to capture the potential seasonality as well as the variances of monthly price within the producing basins, the Company blended the pricing data from these various forecast sources. It should be noted that at the time the 2018 IRP price forecast was developed, Source 4 was the only source to provide a forecast from 2036 onward. Cascade used this source exclusively for its 2037-2038 forecast after normalizing its pricing by comparing the source's forecast to Cascade's blended forecast in years prior and adjusting the source's forecast accordingly. As will be discussed in Section 7, Resource Integration, incremental resource decisions are anticipated to be in place before 2028; consequently, the Company does not believe using a levelized version of Source 4's 2037-38 price forecast had a material impact on resource selection or the avoided costs.

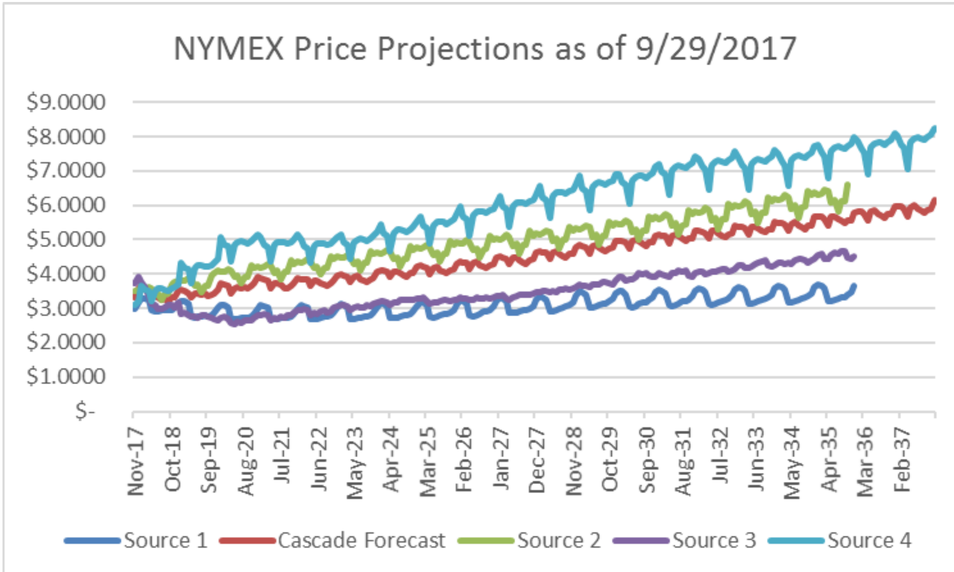
The fundamental forecasts of Wood Mackenzie, the EIA, NWPCC, and Cascade's trading partners are resources for the development of a blended long-range price forecast. Wood Mackenzie publishes a long-term price forecast twice a year to subscribing customers. This forecast was broken down by month through the planning horizon and includes Henry Hub as well as basis differentials for the Company's receiving areas. Cascade also considers the EIA forecast; however, it has its limitations since it is not always as current as the most recent market activity. Further, the EIA forecast provides monthly breakdowns in the short-term, but longer-term forecasts are only by year. Many of the other sources mentioned only provide price forecasts by year. Given Cascade's load profile and the need for more winter gas than summer, the Company developed a pattern based on the market monthly forward prices to create a long-term, monthly Henry Hub price.

With a monthly Henry Hub price determined from the above sources, the Company assigned a weight to each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. These weights were derived by calculating the Symmetric Mean Absolute Percentage Error (SMAPE) of each source versus actual Henry Hub pricing since 2010. The inverse of these errors terms was then used to determine the weight given to each source. A sample of the forecast weighting factors are shown in Table 4-2. The Company gave Sources 2 and 3 the most weight at the start of the planning horizon, as these sources have historically been the most accurate in its short-term forecasting. A comparison of the sources Cascade uses in its forecast and the actual blended forecast is provided in Figure 4-4. As discussed, only one source has a forecast from 2037 onward, so all other sources cut off after 2036.

Table 4-2: Sample of Cascade's Henry Hub Price Forecast Weights

Date	Source 1	Source 2	Source 3	Source 4
18-Jan	7.443%	27.601%	51.155%	13.802%
18-Feb	4.103%	40.758%	43.028%	12.111%
18-Mar	4.142%	42.124%	38.518%	15.216%
18-Apr	4.619%	41.958%	37.283%	16.140%
18-May	5.469%	41.641%	36.015%	16.876%
18-Jun	5.248%	40.041%	37.548%	17.163%
18-Jul	3.654%	41.433%	39.335%	15.578%
18-Aug	3.970%	41.695%	38.973%	15.362%
18-Sep	3.324%	48.277%	34.266%	14.132%
18-Oct	4.354%	49.429%	31.572%	14.646%
18-Nov	4.459%	51.308%	29.570%	14.663%
18-Dec	5.599%	49.377%	29.287%	15.737%

Figure 4-4: Henry Hub Price Forecast by Source ($US/Dth)



Development of the Basis Differential for Sumas, AECO and Rockies

Cascade utilizes the basis differential from Wood Mackenzie's most recently available update and compares that to the future markets' basis trading as reported in the public market because the Company's physical supply receiving areas (Sumas, AECO, and Rockies) are typically traded at a discount to Henry Hub. Correspondingly, the Company applied a weighted average to determine the individual basis differential in the price forecast.

In order to determine the low case and high case, the Company utilized the EIA economic growth factors which are 1.6 for the Low Case, 2.2 for the Reference Case, and 2.6 for the High Case.[3]

Please see Appendix G for the 20-year price forecasts details.

Incremental Supply Side Resource Options

As is more thoroughly described in Section 7, Resource Integration, some of the load growth over the planning horizon will require Cascade to secure incremental supply side resources. The purpose of this section is to identify the potential incremental supply resources the Company considered for the 2018 IRP.

[3] EIA 2017 Annual Energy Outlook

Cascade models its incremental resources simultaneously through SENDOUT®. This allows the Company to evaluate each resource as a potential solution relative to all other resources, without any bias towards any particular option. Cascade utilizes functionality within SENDOUT® to allow the program to deterministically select the optimum timing and quantity of incremental supply resources. Any of the following resources that do not appear in Cascade's final preferred portfolio were deemed to be either not cost-effective or not optimal in comparison with other resource options.

Pipeline Capacity

- **Cross Cascades, Trail West (Palomar, NMax, Sunstone, Blue Bridge, et al):** Trail West is a pipeline starting at GTN's system near Madras, Oregon, and connecting NWP's Grants Pass Lateral near Molalla, Oregon. Since portions of the Company's distribution system are not connected to Molalla, incremental pipeline capacity would be needed to transport gas northbound to certain load centers. NWP has proposed a transport service that would bundle Trail West capacity with NW Natural's northbound Grants Pass Lateral capacity. From Cascade's perspective, this might present an alternative means to move Rockies' gas to the I-5 corridor.

- **GTN Capacity Acquisition:** The Company would acquire currently unsubscribed capacity on GTN in order to secure its gas supplies at liquid trading points to serve Central Oregon.

- **NWP Eastern Oregon Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 24 and Zone ME-OR. Examples of the Cascade service areas that would benefit from this project are Pendleton and Baker City. Similar to a proposed NWP Wenatchee expansion, it would be relatively small scale and could be expected to have a relatively high unit cost.

- **NWP Express Project/I-5 Sumas Expansion Project (Regional or Cascade Specific Project):** Cascade envisions this project as expanding capacity from Sumas on a potential NWP project that is the successor to the Western Expansion project. It would potentially combine Cascade's infrastructure expansion needs with other regional requests from parties such as LDCs, power generators, and large petrochemical projects. The scale of this project is larger, potentially resulting in a more favorable unit cost; although with scale and multiple parties involved, timing for in-service dates may vary by the various participants. Examples of the Cascade service areas that would benefit from this project are Bellingham, Mount

Vernon, Bremerton and Longview. Recently, Avista, Cascade, NW Natural, and Puget Sound Energy agreed to combine their efforts as a group to work with the regional pipelines (GTN, NWP) on potential expansions in the region.

- **NWP Wenatchee Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point (e.g. Sumas) that is designed to serve load growth needs in Zone 10 and Zone 11. Examples of the Cascade service areas that would benefit from this project are Yakima and Wenatchee. Accordingly, it would have a relatively small scale and so could be expected to have a relatively high unit cost.

- **NWP Zone 20 Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 20. Examples of the Cascade service areas that would benefit from this project are Kennewick and Moses Lake. Similar to a proposed NWP Wenatchee expansion, it would have a relatively small scale and so could be expected to have a relatively high unit cost.

- **Pacific Connector:** The Pacific Connector Pipeline project is tied to the development of the Jordan Cove LNG export terminal in Coos Bay, Oregon. This pipeline starts near Malin, Oregon, and would cross NWP's Grants Pass Lateral (GPL) in the vicinity of Roseburg, Oregon. This project presents an opportunity as a potential supply resource for this IRP. Cascade would not be seeking to become a shipper on Pacific Connector. The Company views this project as bundled pipeline supply service from Malin to the Company's citygate. The project was initially denied due to lack of demand. That has changed but it faces considerable opposition. Incremental transport involving GTN might be necessary to ensure transport from Malin to Cascade's GTN receipt point at Turquoise Flats.

- **Southern Crossing Expansion:** FortisBC has proposed a reinforcement project for the Southern Crossing Pipeline that would permit more flow of Alberta gas to Sumas. This would also require an expansion of NWP from Sumas at the Canadian border which in the Company's mind does not need to be modeled since it essentially is replicated by the current inclusion of the NWP I-5 expansion project. This is primarily a price arbitrage opportunity, but the Company does not see any significant advantage to the system at this point given limited availability to move the gas from Sumas. However, Cascade will continue to consider this resource to see if it might make sense as a potentially cost-effective dedicated resource for the Company's direct connect with Westcoast.

Storage Opportunities

- **AECO Hub Storage:** This is Niska's commercial natural gas storage business in Alberta, Canada. The service is comprised of two gas storage facilities: Suffield (South-eastern Alberta) and Countess (South-central Alberta). Although the two AECO facilities are geographically separated across Alberta, the toll design of the NOVA (NGTL) system means they are both at the same commercial point. Capacity at one of the facilities is possible as an alternative resource. Currently, no open season is planned. However, some services are available for limited periods of time but are subject to possible interruption. Incremental transport involving Nova, Foothills, GTN, and possibly NWP would be necessary.

- **Gill Ranch Storage:** Gill Ranch Storage is an underground intra-state natural gas storage facility near Fresno, Calif. It includes a pipeline that links the facility to Pacific Gas & Electric Company's (PG&E) mainline transmission system, allowing it to serve customers throughout California. Storage from this facility would require California Gas Transmission (CGT) transport, which has a potentially cost-prohibitive demand charge of $1.68/Dth. Incremental transport involving GTN would also be necessary.

- **Mist (North Mist II):** According to NW Natural's 2016 IRP (LC 64), Chapter 3, pages 3.34 and 3.35,

  > NW Natural is in the midst of a project called North Mist that would combine new underground storage at Mist and a new transmission pipeline to serve Portland General Electric (PGE) at Port Westward called North Mist. The storage reservoirs currently in service at Mist and those that would be developed as North Mist for PGE do not collectively exhaust Mist's storage potential; other Mist *production reservoirs* that theoretically could be developed by NW Natural into additional storage resources. The primary impediment in doing so is not geological, but the challenges associated with developing new pipeline capacity to move the gas from Mist to the Company's load centers.
  >
  > NW Natural identifies a prospective Mist expansion project for core customer use in this IRP as 'North Mist II.' North Mist II involves 100 MMcf/day of maximum delivery capacity coupled with a maximum storage capacity of 2.0 billion cubic feet (Bcf), and includes a new compressor station and associated appurtenances. These capabilities would be exclusively for utility use. Should a third party want to subscribe to a North Mist II expansion, total deliverability and storage capacity would increase to match those additional subscribed amounts.

Cascade will continue talks with the Mist parties to see if those opportunities may be cost-effective.

- **Ryckman Creek Storage:** Ryckman Creek Resources, LLC, is a wholly-owned subsidiary of Peregrine Midstream Partners, LLC. Ryckman Creek Gas Storage Facility is located near the town of Evanston, Wyoming and approximately twenty-five miles southwest of the Opal Hub. Ryckman Creek has converted a partially depleted oil and gas reservoir into a gas storage facility with 35 BCF of working gas and a maximum daily withdrawal rate of 480,000 Dths/d. Ryckman Creek currently has interconnects with Questar Gas Pipeline, Kern River Transmission, Questar Overthrust Pipeline, Ruby Pipeline, and NWP. Incremental transport involving Questar and possibly Ruby would be necessary (Cascade's transportation contract with Ruby is currently winter-only).

- **Wild Goose Storage:** Wild Goose is located north of Sacramento in northern California and was the first independent storage facility built in the state. The facility commenced full commercial operations in April 1999 and in April 2004 completed its first expansion. Storage from this facility would require California Gas Transmission (CGT) transport, which has a potentially cost-prohibitive demand charge of $1.68/Dth. Incremental transport involving GTN would also be necessary.

Other Alternative Gas Supply Resources

- **Satellite LNG:** Some gas utilities rely on satellite LNG tanks to meet a portion of their peaking requirements. The term satellite is commonly used because the facility is scaled-down and has no liquefaction capability. Instead, its usefulness revolves around the availability of another (no doubt larger) facility with the ability to supply the LNG to fill its tank(s). LNG facilities in this context are peaking resources because they provide only a few days of deliverability, and should not be confused with the much larger facilities contemplated as LNG export or import terminals. The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site operated during cold weather episodes when vaporization is required. Since Satellite LNG has no on-site liquefaction process, the facility is fairly simple in design and operation. While likely as expensive as some pipeline projects, Satellite LNG may be more practical in areas where pipeline capacity shortfalls for peak day are the highest and most immediate. The addition of satellite LNG could defer significant pipeline infrastructure investments for several years.

- **Bio-natural gas (BNG):** BNG typically refers to gas produced by the biological breakdown of organic matter in the absence of oxygen. BNG originates from biogenic material and is a type of biofuel. One type of BNG is produced by anaerobic digestion or fermentation of biodegradable materials such as biomass, manure or sewage, municipal waste, green waste, and energy crops. This type of BNG is comprised primarily of methane and carbon dioxide. The principal type of BNG is wood gas, which is created by gasification of wood or another biomass. This type of BNG is comprised primarily of nitrogen, hydrogen, and carbon monoxide, with trace amounts of methane. The gases, methane, hydrogen and carbon monoxide, can be combusted or oxidized with oxygen. Air contains 21% oxygen. This energy release allows BNG to be used as a fuel. It can also be utilized in modern waste management facilities where it can be used to run any type of heat engine to generate either mechanical or electrical power. BNG is a renewable fuel, which can be used for transport and electricity production, so it attracts renewable energy subsidies in some parts of the world. Cascade has had preliminary discussions with several bio digester developers who are looking to participate in California's Renewable Identification Number (RINs) market. Also, the Company has had discussions with developers on biogas projects that use renewable energy to capture CO_2 from industrial processes and convert it to several commodities, one being methane. This biogas can then be re-injected into a distribution system. Costs are projected to be $30/dth and are not economically viable at this time. Cascade continues to monitor the BNG activities of companies such as PG&E, Intermountain Gas, Sempra Utilities, and Puget Sound Energy.

- **Re-alignment of Maximum Daily Delivery Obligations (MDDO):** Cascade has long held more delivery rights than receipt rights on NWP under its principle 100002 agreement. This was a result of FERC Order 636, when NWP was required to assign upstream capacity directly on GTN (formerly known as Pacific Gas Transmission) to the shippers that were using that capacity. NWP allowed the direct assignment as part of the conversion from their merchant role to an open access pipeline. However, NWP did not lower its capacity contract to reflect the direct assignment. In effect, this increased Cascade's system capacity by the amount GTN would directly be providing to Cascade. On the plus side, this gives Cascade great flexibility to utilize 316,994 Dths/day of delivery rights vs 205,123 Dths/day of receipt rights. Cascade has the right to deliver gas to any delivery point within Washington and Oregon so long as the total MDDOs are not exceeded. Cascade and NWP have worked continuously in recent years for ways to address Cascade's potential peak day capacity shortfalls through re-alignment of the Company's contractual rights where possible, which mitigates the need to acquire incremental NWP capacity through expansions.

Cascade considers Unconventional Gas Supply Resources such as supplies from a LNG Import Terminal, local bio-natural gas or other manufactured gas supply opportunities as speculative supply side resources at this point in time. Ultimately these unconventional gas supply resources are treated as alternative resources and have to compete with traditional gas supplies from the conventional gas fields in Canada or the Rockies for inclusion in the Company's portfolio planning.

Supply Side Uncertainties

Several uncertainties exist in evaluating supply side resources. These include regulatory risks, deliverability risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission (FERC) or Canada's National Energy (NEB) Board rulings that may impact the availability and cost of interstate pipeline transportation.

Deliverability risk is the risk that the firm supply will not be available for delivery to the Company's distribution system. Purchasing resources from larger producers or marketers who typically have gas reserves in multiple locations may minimize this risk. The risks associated with prices rising or falling during any winter period represent another supply side uncertainty. To the extent the Company purchases firm contracts that are tied to an index price, it may be at risk for paying more than was initially anticipated for the resource after the resource decision has been made. Price risks associated with climbing prices can be minimized through the use of fixed price contracts or through the use of financial derivatives.

As the United States continues to search for environmentally friendly, economically viable options to displace gasoline, natural gas is seen as a fuel that could significantly contribute to lessening American dependency on foreign oil. It should be noted that several proposals being discussed or that are in process involve a number of Canadian upstream pipelines which could have a direct impact on the availability of supply or at least may pose potential risks to increases in the price of supplies sourced from British Columbia and Alberta. For example, earlier this year, TransCanada executed transportation agreements with 23 companies to transport approximately 1.42 million dekatherms per day at a notable discount rate of approximately $0.65 US per dekatherm from Empress, Alberta, to southwestern Ontario on their mainline system. The current rate is $1.60 US per dekatherm.[4] This new service may impact the amount of Alberta gas available for companies such as Cascade. The Company will continue to monitor and be actively involved in the various pipeline forums as these initiatives develop.

[4] Financial Post, October 2, 2017.

Financial Derivatives and Risk Management

Cascade constantly seeks methods to ensure customers of price stability. In addition to methods such as long-term physical fixed price gas supply contracts and storage, another means for creating stability is through the use of financial derivatives. The general concept behind a derivative is to lock-in a forward natural gas price with a hedge, consequently eliminating exposure to significant swings in rising and falling prices. Financial derivatives include futures, swaps, and options on futures or some combination of these.

Natural gas futures contracts are actively traded on the NYMEX. The use of futures allows parties to lock-in a known price for extended periods of time (up to six years) in the future. Contracts are typically made in quantities of 10,000 Dths to be delivered to agreed-upon points (e.g., NWP Sumas, Westcoast Station 2, NGTL AECO, NWP Rockies, etc.).

In a swap, parties agree to exchange an index price for a fixed price over a defined period. In this scenario, Cascade would be able to provide its customers with a fixed price over the duration of the swap period. In theory, the price would be levelized over the long-term. Futures and swaps are typically called costless because they have no up-front cost.

Unlike futures and swaps, an option-only provides protection in one direction - either against rising or falling prices. For example, if Cascade wanted to protect customers against rising gas prices but keep the ability to take advantage of falling prices, Cascade would purchase a call option on a natural gas future contract. This arrangement would give the Company the right (but not the obligation) to buy the futures contract at a previously determined price (strike price). Similar to insurance, this transaction only protects the Company from volatile price spikes, via a premium. The premium is typically a function of the variance between the strike price compared to the underlying futures price, the period of time before the option expires, and the volatility of the futures contract.

Cascade's GSOC oversees the Company's gas supply hedging strategy. The Company's current gas hedging strategy is outlined below:

Hedged Fixed-Price Physical or Financial Swaps

- Year one up to 40% of annual requirements
- Year two set at up to 25%
- Up to 20% hedged volumes for year three

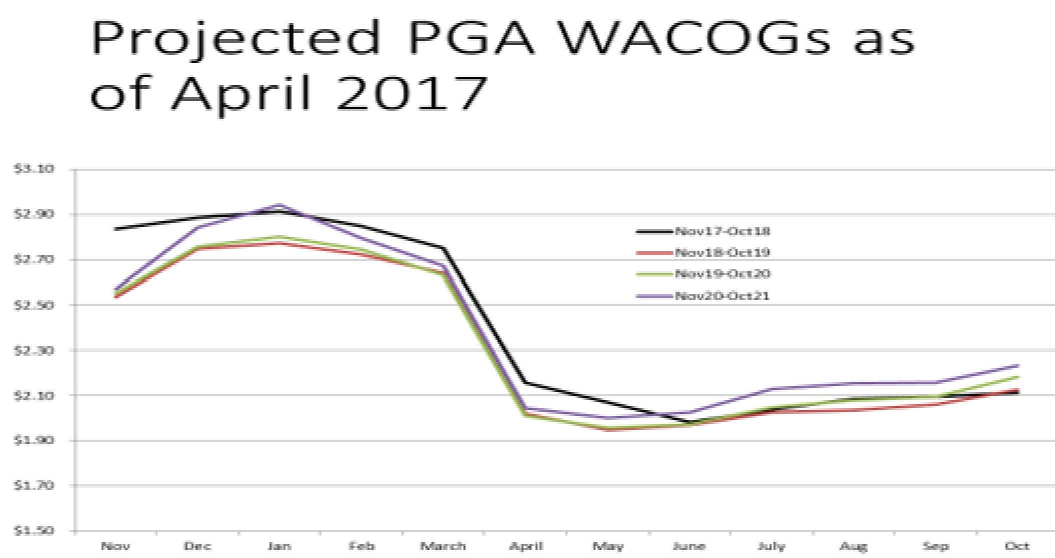
Depending on market conditions, the strategy allows for the ratchets to increase to 75%, 50%, and 30%, respectively, provided current market information supports moving to a different level.

Cascade may employ prudent risk management strategies within designated parameters to minimize the risk of operating losses or assumption of liabilities from commodity price increases because the price the Company pays for gas is subject to market conditions. Risk is associated with business objectives and the external environment. The number of hedging strategies to deal with risk are almost infinite. To manage risk, it is categorized by whether the risk is one to be avoided, one to be accepted and controlled, or a risk left uncontrolled. When a risk is high impact with a high likelihood of occurrence, the risk is probably too high in relation to the reward and should be avoided. It is reasonable to accept business risks that can be managed and controlled. For some risk, the measurable impact is low and the risk may not be worth controlling at all. These are risks where the Company can absorb a loss with little financial or operational effect. The Company's policy is directed toward those risks that are considered manageable, controllable, and worth the potential reward to customers. This manageable risk includes acceptable analysis of the possible side effects on the financial position of the Company as compared to the rewards.

The use of derivatives is permitted only after identified risks have been determined to exceed defined tolerance levels and are considered unavoidable. Cascade's GSOC makes these decisions. In recent years, GSOC has adjusted the percentage of the portfolio hedged based on volatility of the market. For example, in the early 2000s, the Company hedged up to 90% of the base gas supply portfolio. When MDU Resources acquired Cascade in 2007, this threshold was reduced to 75% to align with MDU Resources' Corporate Derivatives Policy. As the market began to fall dramatically in the 2008-2010 period, the Company continued to lower the percentage to approximately 30%. Current MDU Resources' corporate policy encourages Cascade to keep the hedging percentage less than 50%. For the 2018 procurement design GSOC felt that with Cascade's unique load and wide geographical profile, the lack of price volatility would potentially expose the Company to unreasonable premiums on derivatives. Therefore, GSOC chose to hedge using fixed priced physicals. Currently, Cascade hedges approximately 40% of the portfolio using fixed priced physicals.

The Company entered into fixed price physical transactions rather than executing financial swaps for the current programmed buying period. Fixed prices consist of locked-in prices for physical supplies. As will be further described in this section, the Company utilizes a programmed buying approach for locking in or hedging gas supply prices. In light of the relative lack of volatility in current prices, abundant supply, concerns regarding the administrative impacts of the Dodd-Frank Wall Street Reform Act, and an open hedging docket in Oregon and a new hedging policy in Washington, Cascade has not executed any new financial derivatives or considered any for the 2018 IRP. The Company still monitors the outer years and stands ready to execute financial swaps when market and pricing conditions are more favorable. At the time the current procurement strategy was made the forward price spread between the November 2017 through October 2018 period and the November 2020 through October 2021 period was less than 20%, which was deemed a reasonable and manageable spread given market intelligence available. Figure 4-5 provides a graph showing the Company's projected weighted average cost of gas (WACOG) for the 2018 IRP by PGA year.

Figure 4-5: Potential Cascade WACOG as of April 2017



On March 13, 2017, the Washington Utilities and Transportation Commission (WUTC) issued its Policy and Interpretative Statement on Local Distribution Companies' (LDCs) Natural Gas Hedging Practices in Docket UG 132019. This policy can be found at the following link: https://www.utc.wa.gov/docs/Pages-/DocketLookup.aspx?FilingID=132019. This statement provided guidance on how LDCs should develop and implement more robust risk management strategies, analyses and reporting related to hedging activities. The OPUC initiated Docket UM 1720 as a result of long-term hedging guidelines proposed by NW Natural in their 2014 IRP. Throughout both processes Cascade has provided comments and explanations of its risk management efforts. On an interim basis, the Company will continue to utilize the currently approved hedging plan while implementing a more robust hedging strategy over the course of the next two years. The Company will continue to participate actively in Docket UM 1720.

Portfolio Purchasing Strategy

GSOC oversees the Company's gas supply purchasing strategy. Based on current stable prices and a robust supply picture, the Company considers contracting physical supplies for up to five years (based on a warmer-than-normal weather pattern). The Company's current gas procurement strategy is to secure physical gas supplies for approximately one-third of the core portfolio supply needs each year for the subsequent rolling three-year period. This method ensures some portion of the current market prices will affect a portion of the next three years of the portfolio.

In Spring 2017, GSOC approved a portfolio design for three years as follows:[5]

- Portfolio consists of physical supply procurement (index and fixed) design based on a declining percentage each year, accordingly: Year 1: Approximately 80% of annual requirements; Year 2: 40%, Year 3: 20%.
- 80% allows more flexibility operationally.
- Allows Cascade to be in the market monthly through FOM purchase or Day Gas purchases.
- Hedged percentages (fixed-price physical) set at a maximum of 40% of annual requirements. Year 2 is set at 25%, and 20% hedged volumes for Year 3.
- Due to new WUTC hedging policy, may need to consider puts, calls, or financial derivatives to address fixed-priced physicals that may become out of synch with the market.
- GSOC will consider a modification of this plan if the outer year three-year forward price is 20% higher/lower than the front month over a reasonably sustained period.
- The portfolio can always be modified with additional years if a significant discount price materializes.
- Maintain a diversity of physical supplies from Alberta, British Columbia, and Rockies.
- Maximize supplies from the regions that afford the lowest prices, taking into consideration available gas supply, pipeline transport and known operational conditions. Gas from AECO is currently the lowest-cost gas in the Company's supply portfolio. Station 2 is also relatively inexpensive, but the Company has limited available T-South transport under contract. Sumas is often the highest-priced supply, but in recent times it has been less expensive than Rockies except for certain times during the winter.
- Include a small level of annual supplies.
- Annual load expectation (November through October) is approximately 30,000,000 dths, consistent with recent load history.
- Considerations of structured products, caps, floors, etc., are not to exceed 5% of overall contract supply target.

[5] GSOC annually determines the number of years (zero to five) to include in the rolling portfolio plan.

Under this procurement strategy approximately 10% to 20% of the annual portfolio is to be met with spot purchases. Spot purchases consist of either first of the month transactions, executed during bid week for the upcoming month, or day purchases which are utilized to meet incremental daily needs.

Once GSOC has approved the portfolio procurement strategy and design, the Company employs a variety of methods for securing the best possible transaction under existing market conditions. Cascade employs a bidding process when procuring fixed priced physical, indexed spot physical, as well as financial swaps used to hedge the price of underlying index based physical supplies. In the bidding process, the Company alerts a minimum of three suppliers and/or financial counterparties of the specific gas supply transactions Cascade plans to fill. Cascade then collects bids from these parties over a period of time for the packages sought, comparing the indicative pricing to each party as well as comparing the information to market intelligence available at the time. Ideally, after monitoring these indicatives and the market, Cascade awards the specific packages to individual parties. Naturally, price is the principle factor; however, Cascade also considers reliability, financial health, past performance, and the party's share of the overall portfolio so that the Company ensures party diversity. It should be noted that the lowest market price may occur during a period when the Company is initially gathering the price indicatives; in that situation there is a risk that a sudden price run-up may lead to filling the transaction at the higher end of the bids over time, or delay the acquisition to another time. However, the reverse is also true—the initial price indicatives may start high and drop over time allowing us to capture the transaction on the downward swing. In the end, timing is always a factor as the market cannot be predicted with any certainty.

Cascade follows a similar process when it submits a formal request for proposal (RFP) to the various suppliers. Parties are asked to provide offers on specific packages, but are also encouraged to propose other transactions or packages that they feel may be of interest in helping Cascade secure financially attractive and flexible transactions to meet the Company's needs. This process requires additional analysis regarding operational reasonableness, timing, and volumes. Price comparisons also become more complicated since pricing could be tiered; part of a structure deal may be tied to an index or contains floors, caps, etc. Cascade utilizes TruMarx's COMET transaction bulletin board system to assist in communicating, tracking, and analyzing these RFP activities.

Conclusion

Cascade's 20-year supply side resource goal is to continue to meet the energy needs of its core market customers. This is accomplished through a package of services that combines adequate gas supplies and cost-effective winter peaking services with long-term pipeline transportation contracts and sufficient distribution system capacity at the lowest possible cost. The Company has identified several transport, storage, and other alternative resources which may be modeled to join the Company's existing demand and supply side resources to address the load demand needs over the planning horizon.

SECTION 5

AVOIDED COSTS

Overview

The avoided cost is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy conservation. The avoided cost forecast can be used as a guideline for comparing energy conservation with the cost of acquiring and transporting natural gas to meet demand.

This section presents Cascade's avoided cost forecast and explains how it was derived. While the IRP is only a 20-year plan, avoided costs are forecast for 45 years to account for the full measure life of some conservation measures, such as insulation which has a 30-year life. The avoided cost forecast is based on the expected cost scenario.

Key Points

- Avoided cost forecasting serves as a guideline for determining energy conservation targets.
- Cascade's avoided cost includes fixed transportation costs, variable transportation costs, fixed storage costs, commodity costs, a carbon tax, a risk premium, and a 10% adder.
- In future IRPs, the Company may include a value for avoided or delayed distribution investment.
- The total avoided cost ranges between $0.4204 and $1.2078/therm over the 20-year planning horizon.

Costs Incorporated

The components that go into Cascade's avoided cost calculation are as follows:

$$AC_{nominal} = (TC_f + TC_v + SC_f + SC_v + (CC * C_{tax}) + DSC + RP) * E_{adder}$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year. To put this into real dollars you must apply the following: Avoided Cost/ (1+discount rate)^Years from the reference year.
- TC_f = Fixed Transportation Costs
- TC_v = Variable Transportation Costs
- SC_f = Fixed Storage Costs
- SC_v = Variable Storage Costs
- CC = Commodity Costs
- C_{tax} = Carbon Tax
- E_{adder} = 10% Adder for Non-Quantifiable Environmental Benefits
- DSC = Distribution System Costs
- RP = Risk Premium

The following parameters are also used in the calculation of the avoided cost:

- The most recent load forecast (8/4/2017);
- The inflation rate used is tied to the Consumer Price Index (CPI); and
- The discount rate of 6.35% (Cascade's After-Tax Marginal Weighted Average Cost of Capital).

Understanding Each Component

- **Fixed Transportation Costs**

  Fixed transportation costs are the cost per therm that Cascade pays for the right to move gas along an upstream pipeline. As is implied by the name, this cost is incurred whether gas flows along a pipeline or not. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reach through settlement or hearing) must be approved by the Federal Energy Regulatory Commission (FERC) . To model rate increases in its forecast, Cascade multiplies its transportation costs by the CPI escalator every four years. Four years is a proxy since rate cases are not filed each year. Fixed transportation costs differ for various jurisdictions. For instance, some contracts do not serve Oregon, so these costs would be excluded from an Oregon-specific avoided cost, but included in a Washington- or system-wide calculation.

  For its 2018 IRP, Cascade transportation forecasts shortfalls to begin in 2019. Once these shortfalls begin, the next therm saved would not apply to existing contracts, but rather would prevent the need to acquire additional transportation. To this end, fixed transportation costs after 2018 represent the average reservation rate of all incremental contracts that would be used to solve shortfalls. Importantly, in some cases these costs are an estimate based on information from the pipelines, and furthermore, should be treated as confidential as any incremental fixed transportation costs could ultimately be a negotiated rate.

- **Variable Transportation Costs**

  Variable transportation costs are the cost per therm that Cascade pays only if the Company moves gas along a pipeline. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reach through settlement or hearing) must be approved by the Federal Energy Regulatory Commission

(FERC). To model rate changes in its forecast, Cascade multiplies its transportation costs by the CPI escalator every four years. Four years is a proxy, since rate cases may not be filed each year. Variable transportation costs differ based on the jurisdiction the calculation represents. Some contracts do not serve Oregon, for instance, so these would be excluded from an Oregon-specific avoided cost, but would be included in a Washington- or system-wide calculation.

For its 2018 IRP, Cascade forecasts shortfalls to begin in 2020. Once these shortfalls begin, the next therm saved would no longer apply to existing contracts, but would rather prevent the need to acquire additional transportation. To this end, variable transportation costs after 2018 represent the average demand charge of all incremental contracts that would be used to solve shortfalls. It is worth noting that these costs are estimated based on information from the pipelines, and should be treated as confidential as any incremental variable transportation costs could ultimately be a negotiated rate. These costs are still inflated by the CPI escalator every four years to mimic the occurrence of potential rate cases.

- **Fixed Storage Costs**

Fixed storage costs are the cost per therm that Cascade pays for the right to store gas at a storage facility. As is implied by the name, this cost is assessed regardless of whether gas is stored. This rate is set by the various storage facilities and can be changed if the facility-owner files a rate case and FERC or NEB approves it. To model rate increases in its forecast, Cascade multiplies its storage costs by the CPI escalator every four years since rate cases may not be filed each year. As stated earlier, Cascade does not forecast a need to acquire additional storage, so the current storage rates are used in this calculation for the entire planning horizon.

- **Variable Storage Costs**

Variable storage costs are the cost per therm that Cascade pays for the inventory held at a storage facility. This rate is set by the various storage facilities and can be changed if the storage operator files a rate case, subject to FERC or NEB approval. To emulate rate increases in its forecast, Cascade increases its storage costs by the CPI escalator every four years. Four years is used as a proxy since rate cases are not filed each year. As stated earlier Cascade does not forecast a need to acquire additional storage, so the current storage rates are used in this calculation for the entire planning horizon.

- **Commodity Costs**

  Commodity Costs are the costs of acquiring one therm of gas. Since Cascade does not know where it will purchase the next therm of gas, all three basins that Cascade purchases gas from (AECO, Sumas and Rockies) are weighted equally. The price that is used for each year's calculation is the December monthly price from Cascade's 20-year price forecast, as it would be expected that the therm of gas saved would occur on Cascade's peak day, which is modeled as December 21st of each year.

- **Carbon Tax**

  Once the Company has calculated its average cost of gas, a price for an expected carbon tax must be added. Cascade's avoided cost workbook has a tab labeled "Tax" that converts the cost of a tax in dollars per metric ton to dollars per dekatherm. Currently, Cascade forecasts for a scaling carbon tax, starting at $10/metric ton in 2018 and increase by $10/metric ton each year until 2023, where the tax is capped at $60/metric ton. This is based on a 2013 study performed by Portland State University.[1] This results in a $0.583 cost per dekatherm increase, or $0.0583 cost per therm increase, for each $10/metric ton. Since the Company can serve both Washington and Oregon with gas from all three basins, the calculation for commodity cost is the same for Washington and Oregon.

- **Environmental Adder**

  Cascade complies with ORS 469.631(4) and includes the 10% adder for non-quantifiable environmental benefits initially recommended by the Northwest Power and Conservation Council prior to the practice being codified in statute. The 10% adder is added after the cost of gas and taxes are applied.

- **Distribution System Costs**

  Distribution system costs capture the costs of bringing gas from the citygate to Cascade's customers. At this time, Cascade's distribution system costs are not included in the Company's avoided cost calculation. The Company continues to work on developing a methodology for quantifying its distribution costs for the purposes of avoided cost calculation.

[1] https://www.pdx.edu/nerc/sites/www.pdx.edu.nerc/files/carbontax2013.pdf

- **Risk Premium**

  Risk Premium attempts to capture costs associated with hedging, such as the premium associated with financial derivatives. Cascade currently takes the approach that a prudent risk management program should ultimately be cost neutral, as a hedge would only be entered into when a need to mitigate risk occurs. At this time, Cascade's risk premium is a zero value. Cascade will continue to examine this for futures IRPs.

Application

The 2018 IRP makes several enhancements in calculating and applying the avoided costs. This cost figure becomes the foundation for many prudency determinations both operationally and from a resource planning perspective. It may be helpful to think of the final avoided cost figure as something of a cutoff point. Any action that would save a therm of gas could be evaluated based on the cost per therm saved of that measure. If that number is lower than the avoided cost, it may make sense to implement that measure. If not, such a measure may not be optimal to engage in. In Oregon, Cascade works with the Energy Trust of Oregon (ETO) to set targets based on the calculated avoided cost figure, and to implement programs to achieve them.

Results

Table 5-1 displays the avoided cost by each conservation zone over the 20-year IRP horizon. For the 2018 IRP the system avoided costs range between $0.4204/therm and $1.2078/therm over the 20-year planning horizon.

As mentioned earlier, the avoided cost is based on the 20-year expected scenario. Overall, avoided costs for the 2018 IRP are higher than in recent IRPs. Other than the fixed cost increases due to the inclusion of several alternative resources selected as part of the preferred portfolio, the inclusion of a scaling carbon tax is the main driver for higher costs. The 45-year avoided costs and other detailed tables of avoided costs, including various carbon scenarios, are found in the Excel version of Appendix H.

Table 5-1: Avoided Costs by Conservation Zone (Cost per Therm)

Year	Zone 1 Avoided Cost	Zone 2 Avoided Cost	Zone 3 Avoided Cost	Oregon Avoided Cost	Washington Avoided Cost	System Avoided Cost
2018	$ 0.434922	$ 0.434922	$ 0.434922	$ 0.420425	$ 0.434922	$ 0.423868
2019	$ 0.512113	$ 0.526231	$ 0.660431	$ 0.496729	$ 0.566259	$ 0.594917
2020	$ 0.605459	$ 0.619577	$ 0.753777	$ 0.590075	$ 0.659604	$ 0.688263
2021	$ 0.686542	$ 0.700661	$ 0.834861	$ 0.671159	$ 0.740688	$ 0.769347
2022	$ 0.758409	$ 0.772861	$ 0.910228	$ 0.742663	$ 0.813833	$ 0.843168
2023	$ 0.837539	$ 0.851991	$ 0.989358	$ 0.821793	$ 0.892963	$ 0.922298
2024	$ 0.852453	$ 0.866905	$ 1.004272	$ 0.836707	$ 0.907877	$ 0.937212
2025	$ 0.874609	$ 0.889061	$ 1.026428	$ 0.858863	$ 0.930033	$ 0.959368
2026	$ 0.887803	$ 0.902720	$ 1.044516	$ 0.871549	$ 0.945013	$ 0.975294
2027	$ 0.908921	$ 0.923839	$ 1.065634	$ 0.892667	$ 0.966131	$ 0.996412
2028	$ 0.924638	$ 0.939555	$ 1.081351	$ 0.908383	$ 0.981848	$ 1.012129
2029	$ 0.956559	$ 0.971477	$ 1.113272	$ 0.940305	$ 1.013769	$ 1.044050
2030	$ 0.971362	$ 0.986824	$ 1.133795	$ 0.954514	$ 1.030660	$ 1.062046
2031	$ 0.990062	$ 1.005525	$ 1.152496	$ 0.973215	$ 1.049361	$ 1.080747
2032	$ 1.008054	$ 1.023516	$ 1.170487	$ 0.991206	$ 1.067352	$ 1.098738
2033	$ 1.010394	$ 1.025856	$ 1.172828	$ 0.993547	$ 1.069693	$ 1.101079
2034	$ 1.014908	$ 1.030958	$ 1.183519	$ 0.997420	$ 1.076462	$ 1.109042
2035	$ 1.032217	$ 1.048268	$ 1.200829	$ 1.014729	$ 1.093771	$ 1.126351
2036	$ 1.022698	$ 1.038748	$ 1.191309	$ 1.005210	$ 1.084252	$ 1.116831
2037	$ 1.039268	$ 1.055318	$ 1.207879	$ 1.021780	$ 1.100822	$ 1.133402

SECTION 6

DEMAND SIDE MANAGEMENT AND ENVIRONMENTAL POLICY

Overview

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency measures such as insulation or more efficient gas-fired appliances or through load management programs. The Company's primary means for reducing load is through energy efficiency programs that provide customers with financial incentives to install energy efficiency measures or appliances. The Company's energy efficiency programs in Oregon and Washington offer rebates to homeowners, commercial customers, industrial customers, and builders. Because the customer must ultimately make the decision to invest in an energy efficiency measure, DSM is unlike other supply side resources which the Company can independently secure.

Key Points

- Cascade targets saving approximately 41 million therms systemwide over the 20-year planning horizon; 11.86 million therms in Oregon and 29 million therms in Washington.
- Energy Trust of Oregon performed the Technical Potential analysis that informs the savings targets in Oregon for this Plan.
- Cascade has thoroughly integrated the elements of the Company's DSM programs into the full IRP planning process by forecasting the DSM potential at the climate zone level.
- Programs are designed to achieve DSM savings targets by offering customers incentives for installing energy efficiency measures.

This section presents the methodology used to determine the Company's DSM supply curve for the 20-year planning period, the Company's annual savings targets, and a narrative on how DSM goals will be achieved.

This section also considers policy initiatives addressing carbon mitigation that may increase the cost of gas service, thus making more DSM cost-effective in Oregon and Washington, as well as at the federal level.

Cascade's Oregon Energy Efficiency Program

The Energy Trust of Oregon (Energy Trust) administers the following energy efficiency programs in Oregon on behalf of Cascade:

- Residential (Existing and New Home Construction)
  - Single family, moderate income, manufactured homes
    - Weatherization, HVAC & water heating equipment

- Commercial (Existing, New and Multifamily)

  - Retail, offices, schools, groceries & other associated market segments
    - Weatherization, controls, HVAC & water heating equipment

- Industrial & Agriculture (Non Transport Sites)
  - Manufacturing facilities, greenhouses
    - Process improvements, HVAC & water heating equipment, operations and maintenance

The Energy Trust of Oregon is an independent, nonprofit organization initially established to provide energy efficiency services and renewable energy programs to customers of Oregon's investor-owned electric utilities in a restructured electric market. Over time, each independently-owned, local distribution company has transferred control of its energy efficiency programs to Energy Trust as a condition for Commission approval of their independent decoupling mechanisms. As such, Energy Trust provides energy efficiency services to much of Oregon. The Energy Trust's program offerings can be found online at www.energytrust.org.

Cascade offers a comprehensive low-income weatherization program administered by Community Action Agencies (CAAs) who provide whole-home weatherization services to qualified customers at no direct cost to the customer. While the low-income programs are designed to meet the unique needs of qualifying customers, the therm savings acquired in these programs contribute to the total DSM savings target. The Company does not have income data for its customers and, therefore, cannot separately estimate the therm savings potential for just its low-income program. The program details are found in Schedule 33, Oregon Low-Income Energy Conservation Program of the Company's Oregon tariff. Further detail on this program is provided later in this chapter.

Cascade's Washington Energy Efficiency Program[1]

Cascade administers its energy efficiency program in Washington. The methodology for establishing Cascade's long-term planning targets as well as the savings targets are included in both the Company's 2016 IRP, filed in the Washington Utilities and Transportation Commission's (WUTC's) Docket UG 160453. A recapitulation of the Company's short-term goals and initiatives for achieving these goals is available in the Company's Conservation Plan filed in WUTC Docket UG 161253 and included in Appendix D.

The Company's program offerings are broad, including rebates to homeowners for furnaces and water heaters as well as rebates to commercial customers for gas

[1]The Oregon IRP rule requires planning on a system basis, hence the inclusion of Washington energy efficiency descriptions herein.

fryers and gas convection ovens. The sectors covered through these programs include the following:

- Residential (Existing and New Home Construction)
    - Single Family & Manufactured
        - Built Green & Energy Star homes, weatherization, HVAC and water heating equipment, Energy Savings Kits, exterior doors, and programmable thermostats

- Commercial/Industrial (New and Existing)
    - HVAC and water heating equipment, weatherization, controls, energy savings kits, commercial kitchen, clothes washers, and custom

The Company's specific program offerings are detailed in the Company's Washington tariff found online at www.cngconserve.com.[2]

As in Oregon, Cascade offers a comprehensive low-income weatherization program administered by CAAs. The specific details of the Company's offering can be found in Schedule 301, Low Income Weatherization Incentive Program in the Company's Washington tariff.

20-Year Forecast for Cascade Natural Gas Corporations' DSM Potential in Oregon

The Energy Trust analyzes energy savings on a consistent and comparable basis with other supply side resources. All cost-effective energy efficiency is identified via the long-term planning process and Energy Trust is tasked with acquiring this resource on behalf of Cascade. Cascade and Energy Trust work closely together to ensure that the Energy Trust has access to the Company's most recent forecasting data, and is able to effectively integrate this information into their assessment of the Company's DSM potential. Throughout the IRP process, both entities communicated and coordinated on an ongoing basis to maximize forecast accuracy and to provide adjustments to analysis where appropriate. For this planning cycle, the Company and Energy Trust spent nearly a year engaged in constructive, cumulative dialogue, beginning with an exchange of load and customer growth forecasting; and avoided costs; as well as discount and inflation rates. From there, a series of meetings and calls were launched to ensure that both parties were comfortable with the analysis as it proceeded, and that the associated narrative was a reflection of such collaboration.

As a result of this joint-coordination, Energy Trust produced a 20-year forecast of the energy efficiency resource potential for all utilities it serves in Oregon. Below

[2]See Schedule 300, Residential Conservation Incentive Program; Schedule 301, Low Income Weatherization Incentive Program; Schedule 302, Commercial/Industrial Conservation Program. Tariffs are posted online at www.cngc.com.

is a detailed list of each step in Energy Trust's process for determining the long-term, energy efficiency potential:

1. *Identify all available DSM measures:* Energy Trust compiled a list of all commercially available and emerging technology measures for residential, commercial, industrial, and agricultural applications installed in new or existing structures. Appendix D contains tables of the measures studied for each customer class and a summary of the economic assessment for each.

2. *Incorporate demographic information from the utility:* While the first step was being completed, Energy Trust incorporated data from Cascade's demographic study to characterize the existing and forecasted building stock in Cascade's service territory. Using Cascade's customer load forecasts and counts of building stock and customers, Energy Trust applied its knowledge of existing stock conditions and building codes, compiled from third-party researchers and Energy Trust's internal data, to the Company's customer forecast. Energy Trust then estimated the number of measures that could be deployed in the Company's service territory over the 20-year time horizon. The primary sources used to develop these assumptions included:

    a. Northwest Energy Efficiency Alliance's (NEEA) Residential Building Stock Assessment (RBSA)
    b. NEEA's Commercial Building Stock Assessment (CBSA)
    c. Energy Trust Program Data
    d. Industrial Assessment Centers Database
    e. Assumptions derived from Cascade's customer and load data

3. *Determine the technical potential:* The technical potential is the total number of therms that could be saved in Cascade's service territory assuming adoption and installation of all technically feasible measures with energy efficiency potential. Energy Trust assigns all measures listed under Step 1 a technical feasibility factor to account for limitations that might prevent installation; for example, commercial buildings that do not have the space and infrastructure to install a boiler. This technical savings potential does not account for the various market barriers to a 100% adoption rate, which are discussed in the next steps.

4. *Determine the achievable potential:* Energy Trust created the achievable potential by reducing the technical potential by 15% to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85% of the technical potential is the generally accepted method employed by many industry experts, including the Northwest Power and Conservation Council (NWPCC) and National Renewable Energy Lab (NREL).

5. *Determine the cost-effective potential:* Energy Trust created the cost-effective potential by screening all DSM measures using the Total Resource Cost (TRC) test, which is a benefit-cost ratio (BCR) that measures the cost effectiveness of the investment being made in an efficiency measure. The TRC evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than one means the value of benefits is equal to or exceeds the costs of the measure, and is, therefore, cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

   TRC = Present Value of Benefits / Present Value of Costs

   Where the *Present Value of Benefits* includes the sum of the following two components:

   a. *Avoided Costs*: The value of gas energy saved over the life of the measure as determined by the total therms saved multiplied by the Company's avoided costs. The avoided costs include commodity and transportation costs, plus the 10% Northwest Power Act credit, which is meant to provide an economic advantage to energy efficiency, a risk premium value for DSM, and carbon policy adder. [3,4] See Section 5 for a more in-depth conversation on Avoided Costs.

      The total avoided cost for a measure depends upon that measure's expected lifespan (or measure life), end-use, and seasonality of savings. Savings that occur during the winter season are more valuable than savings that occur during the summer season because gas commodity prices are higher during the heating season. The net present value of these benefits is calculated based on the measure's expected lifespan using the Company's discount rate.

   b. Non-energy benefits are also included when present and quantifiable by generally-accepted practices (for example, water savings from low-flow showerheads).

   Where the *Present Value of Costs* includes the sum of the following two components:

   a. The participant's remaining out-of-pocket costs for the installed cost of the measures after state and federal tax credits if applicable; and

[3] Officially known as the Pacific Northwest Electric Power Planning and Conservation Act codified as ORS 469.631 through 469.645

[4] *See*: Section 5 for a discussion of Cascade's avoided cost.

b. Operations and maintenance costs over the life of the measure, if applicable.

Figure 6-1 graphically depicts the difference technical, achievable, and cost-effective potential.

Figure 6-1: Categories of Potential DSM Savings Identified in Energy Trust Forecast

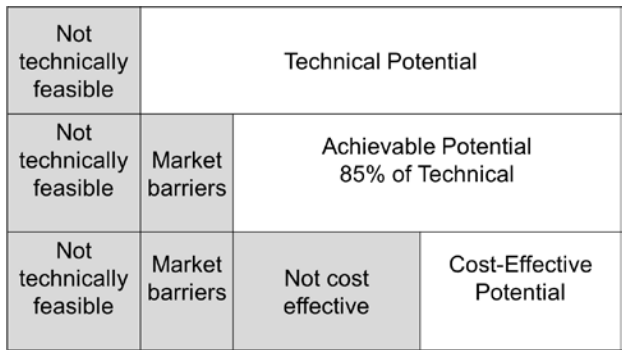


Table 6-1 provides the technical, achievable, and cost-effective potential in Cascade's Oregon service territory by customer class for the next 20-years.

Table 6-1 Summary of Resource Potential (2018–2037)

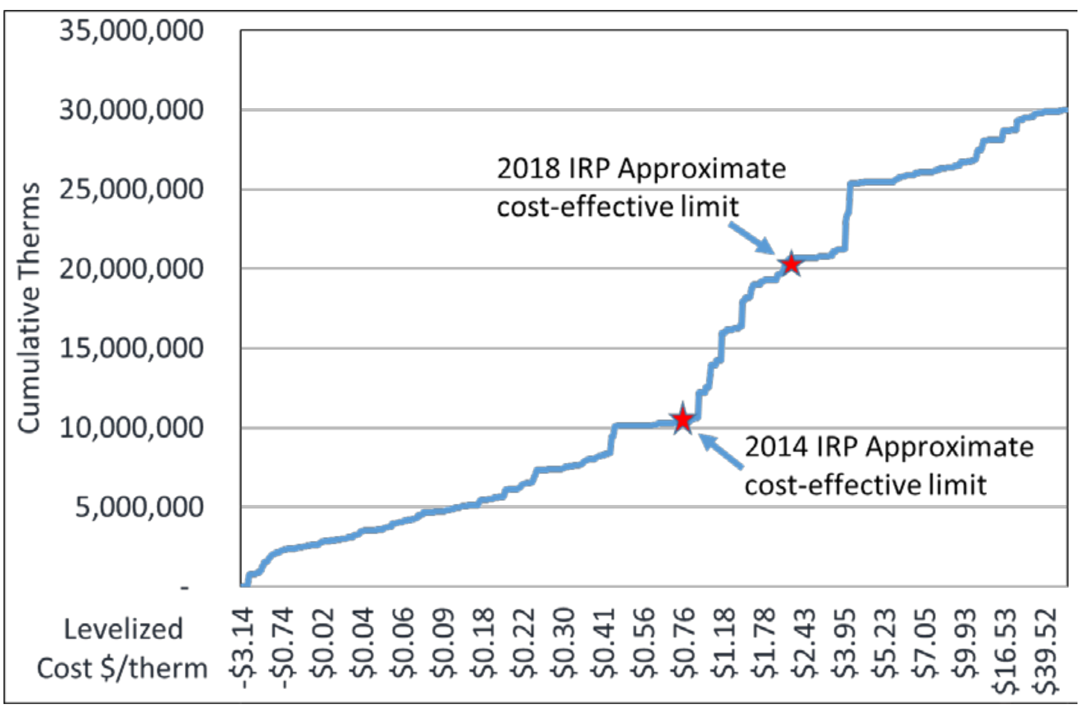
Sector	Technical Potential (Therms)	Achievable Potential (Therms)	Cost-Effective Achievable Potential (Therms)
Residential	17,580,928	14,943,789	12,148,348
Commercial	12,225,805	10,391,934	6,638,878
Industrial	1,957,048	1,663,491	1,627,931
Efficiency Total	31,763,780	26,999,213	20,415,156

The savings discussed in this section are shown as gross savings. Energy Trust publicly reports its Oregon savings and goals in 'net' savings, which are adjusted for spillover and free riders. Spillover occurs when a customer not applying for program incentives reduces his/her energy use or installs energy efficient measures because the program has raised her/his awareness of energy efficiency. Free ridership refers to a customer's participating in the program when the program information or incentive did not influence the customer's efficiency decision. Gross savings are all acquired through the program regardless of the program's influence on customers and best reflect the amount of future gas demand that will be avoided.

6. *Levelized Cost Determination by Measure*: Once the list of measures was compiled, Energy Trust determined a levelized cost per therm for each measure. The levelized cost is the present value of the total cost of the measure over its economic life converted to equal annual payments per therm of energy savings. The levelized cost calculation starts with the incremental capital cost of a given measure. The total cost is amortized over an estimated measure lifetime using the Company's discount rate of 6.35%.[5] The annual measure cost is then divided by the annual energy savings, in therms.

   Levelized costs can be graphically depicted to demonstrate the total potential therms that could be saved at various costs for all conservation measures. Figure 6-2 shows a resource supply curve that can be used for comparing demand side and supply side resources. The two cost thresholds shown as vertical dotted lines represent the approximate levelized cost cutoff that corresponds with the amount of cost-effective DSM potential, as determined by the TRC, when ordering all measures based on their levelized cost. Some measures have a negative levelized cost due to the inclusion of non-energy benefits which outweigh the cost of the measure.

Figure 6-2: Cascade's 20-Year Gas Supply Curve



[5] As required by OAR The 6.35% discount rate is Cascade's Oregon after-tax weighted average cost of capital (and assumes a 1.0% annual inflation rate).

Figure 6-2 shows a larger savings potential than was forecast in the prior IRP. This is largely due to the inclusion of additional measures in the model, as well as the use of a cost-effective override to force the addition of potential savings from measures that are not cost-effective. (This is further explained following Figure 6-4.)

Examples of measures that have been included but are not cost-effective under current valuation methodology include single family residential ceiling, wall, and floor insulation, which are offered under certain criteria, and the 0.67 and .70 EF domestic gas tank water heaters. Part of the rationale for continuing to offer these measures is to maintain consistency in the market and to retain relationships with vendors and trade allies who are relied upon to sell the energy efficiency products.

The OPUC has granted Energy Trust exceptions for the above-stated measures because they meet one of the seven exception criteria established in Order No. 94-550 issued in Docket No. UM 551. Specifically, Commission Order No. 94-590 in Docket UM 551 specifies that the TRC must be used to determine if energy efficiency measures and programs are cost-effective. The same order allows for measures that are not cost-effective to be included in utility programs if it is demonstrated that:

- The measure produces significant non-quantifiable non-energy benefits. In this case, the incentive payment should be set at no greater than the cost-effective limit (defined as present value of avoided costs plus 10%) less the perceived value of bill savings, e.g. two years of bill savings;
- Inclusion of the measure will increase market acceptance and is expected to lead to reduced cost of the measure;
- The measure is included for consistency with other DSM programs in the region;
- Inclusion of the measure helps to increase participation in a cost-effective program;
- The package of measures cannot be changed frequently and the measure will be cost-effective during the period the program is offered;
- The measure or package of measures is included in a pilot or research project intended to be offered to a limited number of customers; and
- The measure is required by law or is consistent with Commission policy and/or direction.

The Commission has provided exceptions for a number measures over the last few years as Energy Trust works to lower costs and design new ways to offer measures in a more cost-effective manner. While there continues to be uncertainty around the future price of gas and whether measure costs can be adequately reduced, the Energy Trust has been allowed ongoing exceptions to these measures and felt it appropriate to include the savings potential from these measures in its DSM potential forecast to not understate the savings potential that exists.

The following lists all measures that have been included in the analysis by using the cost-effective override:

- Commercial Insulation and Windows
- Residential Furnaces
- New Homes Construction Energy Performance Score (EPS) Pathways
- Residential Smart Thermostats
- Residential Windows
- Residential Insulation (ceiling, floor, wall)
- Residential Tank Water Heater

Tables included in Appendix D depict the 20-year cumulative achievable and cost-effective achievable potential forecast per measure grouped by sector. The tables also include the weighted average levelized cost for the savings of each measure.

Figure 6-3 shows the 20-year DSM supply curves for the technical, achievable and cost-effective achievable savings potentials in Cascade's service territory. This is a cumulative potential; it has not been shaped to represent what Energy Trust expects it can acquire in a given year. Growth over time is primarily driven by new building construction and equipment turnover.

Figure 6-3: Cumulative Potential (2018-2037) by Sector and type of Potential

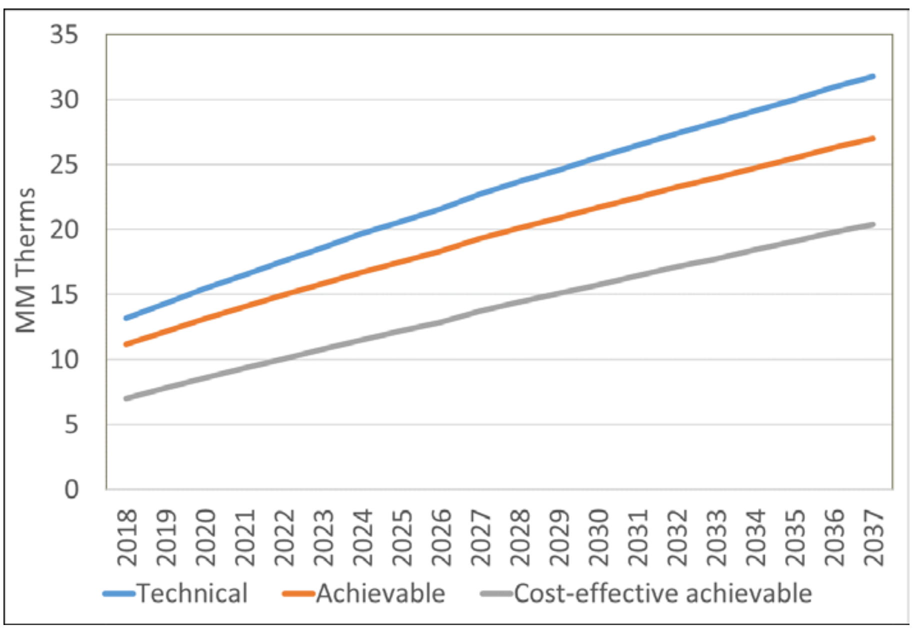


Figure 6-4 provides the technical, achievable and cost-effective achievable savings potentials for the 20-year planning period by customer class.

Figure 6-4: Cumulative Potential (2018-2037) by Sector and Type of Potential

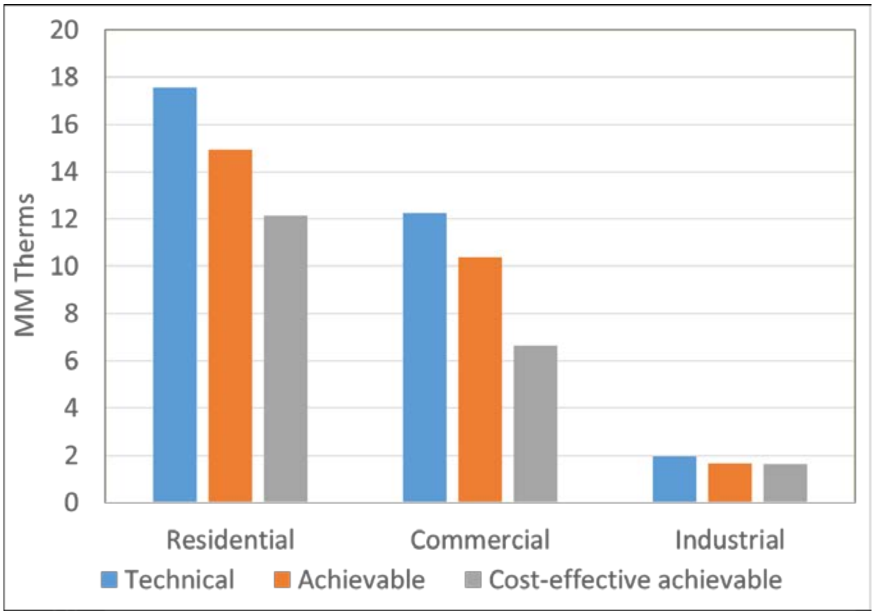


Table 6-2 shows the potential savings in the resource assessment model that was added by employing the cost-effectiveness override option. The cost-effectiveness override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following two criteria:

1. The measure is not cost-effective but is offered through Energy Trust programs under an OPUC exception and is expected to be brought into cost-effective compliance in the near future.

2. The measure is cost-effective using statewide blended avoided costs and is currently offered through Energy Trust programs, but is not cost-effective when modeled with current Cascade-specific avoided costs.

The inclusion of certain cost-effective override measures under the conditions described above is consistent with the approach the Energy Trust has taken for other natural gas utilities. The goal of such analysis is to capture the full range of energy conservation potential in alignment with the energy efficiency resources that Energy Trust is pursuing through current program offerings.

Table 6-2: Cumulative Cost-Effective Potential (2018-2037) due to use of Cost-effectiveness override

Sector	Yes CE Override	No CE Override	Difference
Residential	12.15	5.78	6.37
Commercial	6.64	6.47	0.17
Industrial	1.63	1.63	-
Total DSM:	**20.42**	**13.88**	**6.54**

The cumulative savings from the cost-effective override represent 32% of the total cost-effective potential identified for the 20-year forecast; 97% of these savings come from the Residential Sector. Importantly, while these savings were forced into cost-effectiveness, its effect is mitigated by the amount of savings potential selected for deployment in the final savings projection, which relies on program input and predicts what amount of that cost effective potential Energy Trust anticipates acquiring through its programs. Only a portion of the cost-effective potential from lost opportunity measures--such as new construction and replacement of end-of-life equipment--is expected to be acquired given program budgets, incentive levels, and customer decision making preferences. For example, the New Homes program typically brings in about 35% of the total new homes construction market. Such assumptions, which are based on historical program performance, are considered when generating the final annual savings projection.

Overall, about two-thirds of the Residential technical potential was found cost-effective. In the Commercial sector, approximately half of the technical potential identified in the model is cost-effective. For the Industrial sector, nearly all the technical potential identified is cost-effective.

Figure 6-5 shows the amount of emerging technology savings within each category of DSM potential.[6] In highlighting the contributions of commercially available and emerging technology DSM contributions, the graph indicates that while over six million therms of the DSM technical potential consists of emerging technology, once the cost-effectiveness screen is applied, only a sixth (one million therms) of that remains.

[6]Emerging technology refers to new energy saving measures that are entering, or are expected to enter the market.

Figure 6-5: Cumulative Potential (2018-2037) by Type with Emerging Technology Contribution

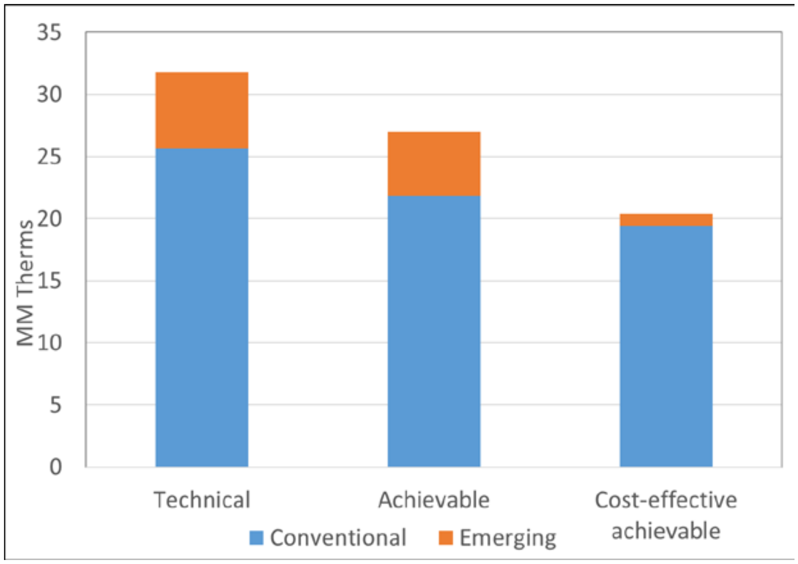
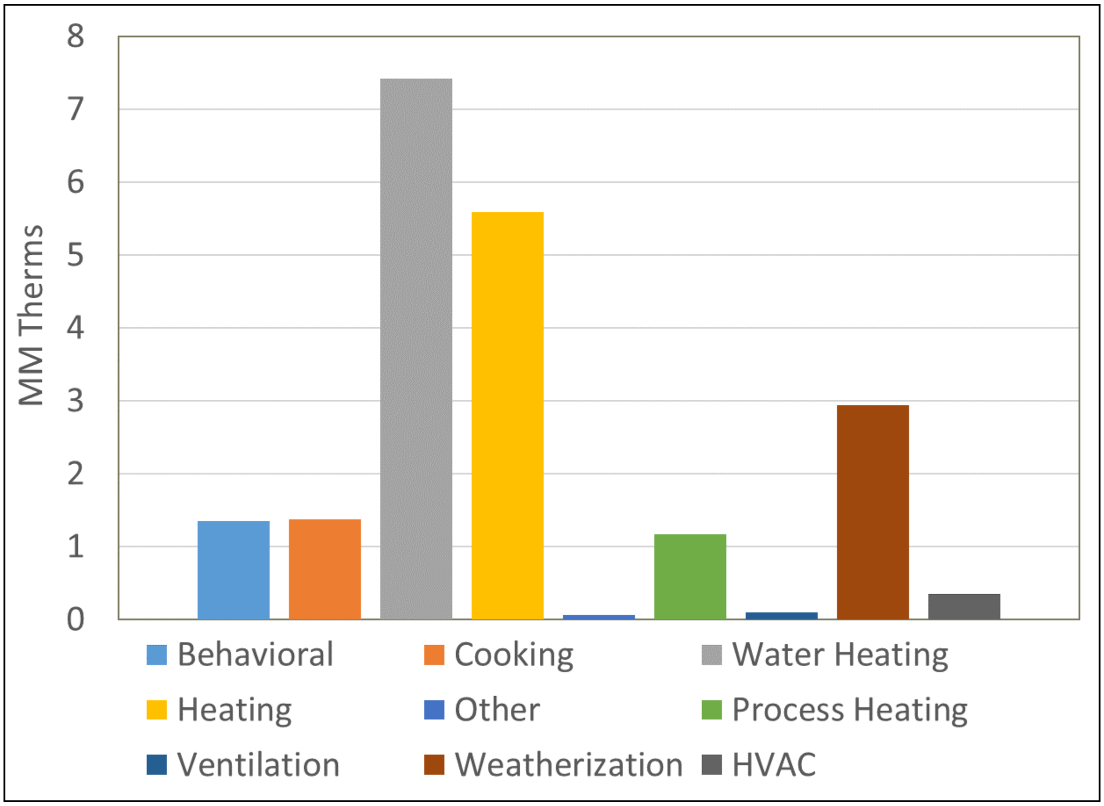


Figure 6-6 below provides a breakdown of Cascade's 20-year cost-effective DSM savings potential by end-use. [7] These figures represent total, cumulative, cost-effective achievable potential as shown in Table 6-1 prior to being reduced by program deployment assumptions.

Figure 6-6: 20-Year Cumulative Cost-Effective DSM Potential by End Use



Water heating and space heating are the most common end uses in Cascade's territory. Water heating measures include water heating equipment from all sectors, as well as low flow showerheads and aerators. Heating potential comes from commercial and residential heating system measures, and heating venting and air conditioning (HVAC) savings come from industrial heating and insulation measures. The behavioral end-use potential comes from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities staff to develop the skills to identify operations and maintenance changes that make a difference in a building's energy

[7] End-uses with water heating savings come from all sectors and cover a range of water heating equipment, including from new construction measures. End-uses with space heating savings potential include commercial and residential heating equipment like furnaces, boilers and controls. It also includes smart thermostats and new home construction savings. End-uses with flat savings potential are cooking, other, water heating, process heating, and HVAC. Due to recent interest in quantifying peak savings, which are most directly related to space heating during the winter, Energy Trust recognizes the need to revisit the assumptions and categorization of load profiles for certain measures in the resource assessment model.

use. It also includes residential personal energy reports and smart home automation devices. The savings from the other category include a variety of measures, but the potential shown here is from greenhouse upgrades offered under the industrial program.

Energy Trust's Modeling Tool

A significant portion of the calculations involved in performing the DSM forecast are completed within Energy Trust's resource assessment tool. This tool is comprised of economic modeling software built in 2014 by Navigant Consulting Inc. in the Analytica software platform. It is used to estimate the technical, achievable, and cost-effective achievable potential for demand-side resources in Cascade's service territory across the residential, commercial, and industrial sectors. The model primarily takes a bottom-up approach and is built from all the measures available across each sector and installed or delivered in homes and businesses. All measures have gas savings and costs associated with them, and incorporate Cascade's customer and load data, as well as many other inputs to determine how many of what measure could potentially be installed into a given building through time. The product of all these factors results in the total 20-year DSM potential available for acquisition to serve Cascade's customers and associated demand.

Modeling Changes and Sensitives in Oregon

Cascade's 2014 IRP and this IRP both used the new Energy Trust model described above. However, it's important to note that the model which drove the current forecast was the product of many updates. This makes it different from the model used in 2014 and accounts for the significant changes in outcomes between the two planning cycles. The following improvements contributed to the changes in energy efficiency potential identified during this DSM forecast:

- <u>Refreshed measure assumptions</u>. Energy Trust has completed two measure update processes since the model was used in Cascade's 2014 IRP. The refreshed assumptions include baseline adjustments, savings and costs updates as well as saturation rates that identify the remaining opportunities for installation. New home construction energy performance score (EPS) pathways included in this study represent a significantly different approach to this program, and resulted in additional savings potential.

- <u>New Measures</u>. New measures, including a commercial behavioral measure known as Strategic Energy Management (SEM), which contributed a significant amount of potential in this DSM forecast, were added.[8] Other new measures include cooking measures for restaurants, industrial measures, and smart thermostats, which added over 760,000 therms of additional cost-effective potential.

- Emerging Technologies. Emerging technology continues to provide additional savings. It is not currently commercially available but is has a reasonable chance of becoming commercially available within the 20-year planning timeframe.

- Updated measure saturation rates from third party research and survey work. The residential building stock assessment (RBSA) and commercial building stock assessment (CBSA)—both undertaken by NEEA--serve as the primary resources for developing residential and commercial measure densities and saturation factors, which characterize the existing building stock and identify the number of possible locations for DSM measures to be installed. Since these studies have not been updated, Energy Trust updated certain measures like showerheads using internal research on historical program performance. Energy Trust also updated saturation rates based on Cascade-specific data.

DSM Projections in Oregon: 2018-2037

The Company foresees 11.86 million therms of its 20-year demand coming from Oregon demand side management measures delivered through the Energy Trust.

After determining the 20-year cost-effective achievable potential, Energy Trust develops a savings projection that represents what Energy Trust believes it can accomplish, based on past program experience and knowledge of current and developing markets. The savings projection is a 20-year forecast of future market penetration by programs for existing measures and new technologies within the cost-effective potential plus forecasted market transformation savings due to the Energy Trust's work towards accelerating building codes in Oregon.

The evolution from technical potential to program savings projects is depicted in Table 6-3 below.

[8] See Appendix D for additional information on Commercial SEM.

Table 6-3: The Progression to Program Savings Projections

<table>
<tr><td>Not technically feasible</td><td colspan="4">Technical Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td colspan="3">Achievable Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td>Not cost effective</td><td colspan="2">Cost Effective Potential</td></tr>
<tr><td>Not technically feasible</td><td>Market barriers</td><td>Not cost effective</td><td>Program design, market penetration</td><td>Program Savings Projection</td></tr>
</table>

Table 6-4 presents the technical, achievable, and cost-effective potentials as well as Energy Trust's therm savings target for the 20-year planning period. The cost-effective DSM savings potentials by program type and year are provided in Appendix D.

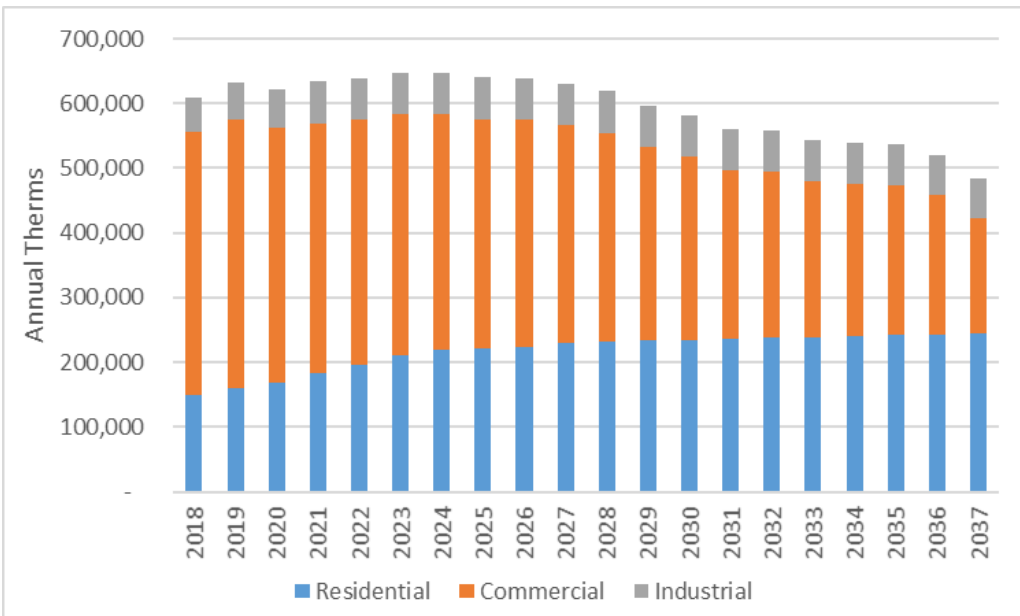
Table 6-4: Savings Projections for Oregon

	Technical	Achievable	Cost-effective	Energy Trust Savings Projection
Residential	17,580,928	14,943,789	12,148,348	4,344,727
Commercial	12,225,805	10,391,934	6,638,878	6,285,500
Industrial	1,957,048	1,663,491	1,627,931	1,245,219
All DSM	**31,763,780**	**26,999,213**	**20,415,156**	**11,875,446**

The final savings projection of 11.86 million therms by 2037 in Cascade's service territory reflects the reduction to the full cost-effective potential of 20.45 million therms due to additional market-related constraints on capturing savings from replacing equipment at end-of-life and measures from new homes and buildings. Such measures are known as *lost opportunity* measures. The opportunity to acquire these savings, if lost, does not reappear again until their useful life has passed. Energy Trust assumes it can acquire a relatively sizable portion of these savings, but does not expect it can leverage all these opportunities when they arise. Energy Trust's savings projection also includes 116,500 therms achieved through known changes to future residential and commercial building codes where Energy Trust played a role in advancing the adoption of these codes and standards. Since energy consumption is reduced when more stringent building codes are adopted, the OPUC has agreed to allow Energy Trust to claim some of the savings since its work in transforming the market influenced the changes in code. This was done for the New Homes and New Buildings programs.

Figure 6-7 depicts Energy Trust's annual savings projection for Cascade's service territory.

Figure 6-7: 20-Year Annual Projected Savings (2017-2036)



The decline in savings from 2019 to 2020 is due to the expiration of savings from the New Homes and New Buildings programs for past work that contributed to building code changes (otherwise known as market transformation savings) as discussed above. While it is likely that additional savings may occur when building codes are updated again, the Energy Trust cannot currently forecast the amount likely to occur in the future.

Figure 6-8 below provides a breakdown of Cascade's 20-year projected annual savings acquisition according to whether the savings occur during the heating season (space heat) or all year (flat). A significant amount of savings is available from heating load which occurs during peak periods.

Figure 6-8: 20-Year Annual Savings Projection by end use

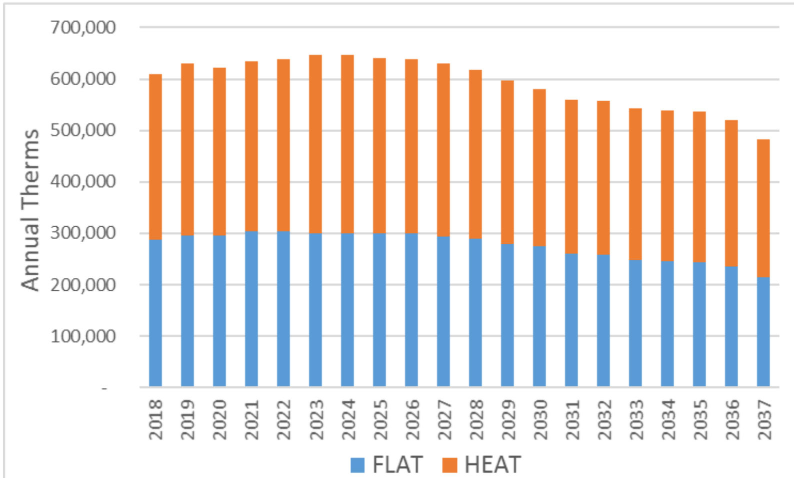
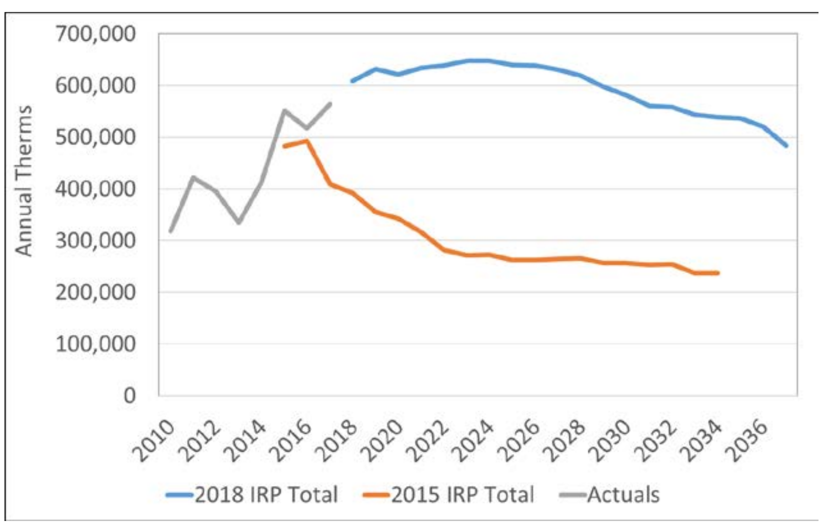


Figure 6-9 shows a comparison between the 2014 IRP and 2018 IRP projected savings deployments, with actual savings performance shown in gray for reference. The spikey nature of the actual savings line is reflective of several factors, including the small size of Cascade's Oregon service territory and the potential of overachieving or failing to miss a savings target due to the impact that large projects can have on overall annual savings achievements. Large projects can be difficult to forecast and often account for variances experienced in historical performance against goal. However, to date, Energy Trust has met or exceeded its goals in five of the last seven years.

Figure 6-9: Annual Actual Savings History and IRP Projection Comparison



Utilizing the *Energy Trust Resource Assessment Model* described above, Energy Trust produced the following DSM projections for Cascade's Oregon service area for the period of 2018-2037. Energy Trust used the following global inputs:

- Cascade supplied its most recent demand forecast and customer count forecast. This data was incorporated into Energy Trust's resource assessment model. Residential customer data was provided at the sector level regardless of housing type, so Energy Trust used Cascade's utility account data to then split the residential forecasts into single family, multifamily, and manufactured homes. Cascade provided Commercial and industrial forecasts to Energy Trust split by market using SIC code. SIC code was then matched with the market groups used in Energy Trust's resource assessment model.

- Energy Trust applied a real (long-term) discount rate of 6.35%.

- Cascade Natural Gas shared avoided cost of conservation values with Energy Trust in May of 2017. The avoided costs were calculated as the gas price forecast plus transport (fixed and variable transportation and storage costs), with the Northwest Power Act 10% cost credit for conservation adder and risk reduction value as well as an expected cost of CO^2 adder.

- The nominal cost per therm values were converted to real values using an inflation rate of 1.0%, which Cascade provided in the same avoided cost file.

The avoided cost value is the benefit per therm of savings from energy efficiency measures.

Energy Trust's analysis complied with OPUC Order No. 16-054 which directed the Company to factor for commercial market transformation savings similar to residential methods. Energy Trust integrated savings into the forecast for commercial, new construction savings for new building codes. Market Transformation savings are based on forecasts of units built to a code that would not have been in place had it not been for the program's efforts to accelerate both the change in code and builder's compliance with code.

Table 6-5 shows the shows the potential therm savings per customer class, per measure type.

Table 6-5: Savings by Customer Class and Measure Type

Measure Type	Residential Therms Saved	Commercial Therms Saved	Industrial Therms Saved
New	2,507,205	1,666,494	
Retrofit	1,438,334	1,775,268	1,076,499
Replacement/Burn-Out	288,850	1,828,489	168,720
Strategic Energy Management		1,004,229	
New Construction Market Transformation	110,338	11,020	

Residential New Construction Market Transformation savings represent Energy Trust's best estimate of annual therm savings to be acquired for Cascade in Oregon. These savings targets include improvements in residential building codes adopted earlier due to Energy Trust's and NEEA's efforts.

Capacity Contributions of Energy Efficiency

Due to an increased focus on the refinement of targeted DSM efforts and the development of strategies for avoiding or delaying distribution system reinforcements, Cascade is assessing the capacity contribution of energy efficiency at the citygate level.

Under Cascade's current analysis, demand is reduced by the inputted level of energy efficiency before any optimization is calculated. However, consistent with Commission Order No. 16-054, the Company is re-examining its approach to DSM analysis and is reviewing NW Natural's capacity contribution analysis. Cascade is also monitoring the emerging conversation taking place at the regulatory level regarding avoided costs and will use the results of this deliberation to shape future resource planning, as appropriate.

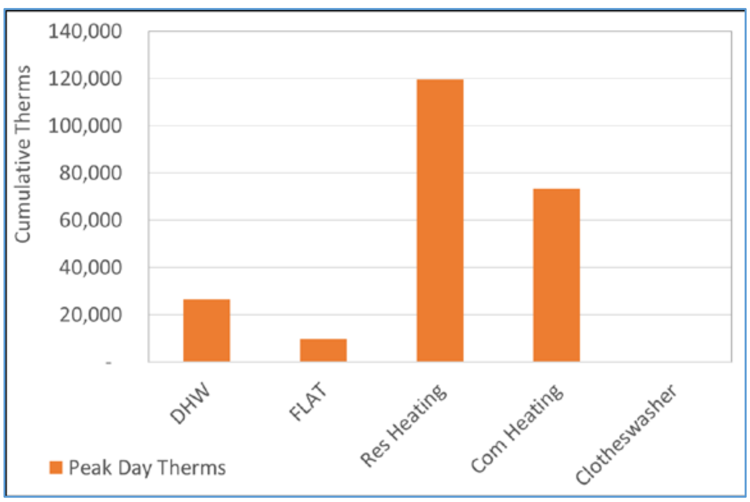
For this planning cycle, the Company is working with the Energy Trust to analyze peak day savings by load profile, with the goal of ultimately translating this into data that can be used to formulate a strategy for addressing peak day demand. A brief analysis of peak-day savings is provided in Table 6-6 below:

Table 6-6: Peak Day/Annual Usage Saving Factors

Peak Day/Annual Usage Savings Factors	
Load Profile	**Peak Day Factor**
DHW	0.40%
FLAT	0.30%
Residential heating	2.10%
Commercial heating	1.80%
Clothes washer	0.20%

Figure 6-10 shows the amount of savings forecast for a peak day based on the factors showed in Table 6-6 as calculated against the amount of savings for these load profiles. Heating measures, which have the highest amount of annual usage coincident with peak, have the most peak savings potential. The total peak savings from this estimate is 230,000 therms or 1.1% of the total cost-effective achievable potential of 20.4 million therms.

Figure 6-10: Peak Day Forecasting



While reductions in peak load from all customers reduce the need for supply side resources, a full adaptation of a specifically targeted peak-management strategy would require reductions in peak load from customers connected to the portion of the distribution system that requires reinforcement. This means that for a DSM program to offer meaningful capacity contributions, the Company would need to consider a more geographically targeted, DSM strategy. Cascade will continue to coordinate both internally and with the Energy Trust to determine the optimal approach for avoiding additional capacity and the need for system reinforcements through energy efficiency.

Program Funding

In Oregon, Cascade charges customers a public purpose charge (PPC), which is a percentage applied to customers' bills. The Company's Schedule 31, PPC was adopted in 2006 with the approval of Cascade's Conservation Alliance Plan in OPUC Docket UG 167. [9] PPC collections are used to fund Energy Trust efforts on behalf of Cascade in Oregon, and on behalf of the two Oregon low-income programs, weatherization and bill payment assistance.

In Washington, Cascade defers program costs for later collection from customers through the Schedule 596, Conservation Program Adjustment charge. Dollars collected through Schedule 596 fund the Company's residential, commercial, and industrial energy efficiency programs and the Company's low-income, weatherization program.

Oregon Low-Income Energy Conservation Program

Cascade partners with the five Community Action agencies that serve low-income households in Central and Eastern Oregon to administer and deliver the Oregon Low-Income Energy Conservation Program (OLIEC) and its associated Conservation Achievement Tariff (CAT) program, which was made permanent on December 1, 2016.

The OLIEC program was designed to increase energy efficiency in low-income households within Cascade's Oregon service area by providing rebates for the installation of certain weatherization and conservation measures following the completion of a home energy evaluation performed by a qualifying Low-Income, 501c3 organization or a Community Action Agency (CAA). The rebates are determined on the basis of the first-year dollar value of the conserved natural gas as reflected by the Company's most recently acknowledged avoided cost of natural gas.

The OLIEC program provides incentives for ceiling, floor, wall and duct insulation; duct sealing; infiltration system upgrades (weather stripping and caulking); high efficiency furnace installations; furnace turn-up and filter replacement; and high-efficiency water heaters. Rebates are also available for new low income residential construction and custom energy efficiency measures on an individual basis with preference for measures that would qualify for rebate in similar projects offered through the Energy Trust.

In addition to the OLIEC rebates, agencies receive an additional $225 for administrative and direct program costs incurred by them.

CAT operates alongside of, and in conjunction, with the OLIEC Program. The CAT

[9] CAP is a decoupling mechanism.

program bridges the gap between the portion of weatherization funding available through OLIEC (the avoided cost of natural gas) and the full cost of work performed for qualified measures. The funds are available to Agencies on a first-come, first-serve basis for the purpose of providing total installed costs for weatherization measures approved under Schedule No. 33, Oregon Low Income Energy Conservation (OLIEC) program. The CAT also provides each agency with a flat fee of $550 for an audit and $300 for an inspection fee. The Total Installed Costs reimbursed under CAT for a single dwelling may not exceed $10,000. Total Installed Costs are defined as all costs incurred for materials and contractor labor necessary to perform tariff-eligible natural gas weatherization work at a qualified customer premise.

The Company began piloting CAT on January 1, 2014, with a termination date of December 31, 2015. The initial CAT pilot was funded using $400,000 of unspent OLIEC dollars. In order to continue studying CAT's ability to increase OLIEC's reach to low income customers, the Company filed Advice No. O15-11-02 at which time it asked to extend the CAT pilot term to December 31, 2017, which the Commission approved at its December 15, 2015 public meeting. In 2016, Cascade filed to revise its public purpose charge so collections for the CAT program would be $400,000 over twelve months. On Staff's recommendation, the Commission approved a $200,000 increase in collections for CAT. Since this amount did not prove sufficient, the Company filed an application for deferred funding on March 15, 2016, which was docketed as UM 1765. Cascade provided program information, and engaged in collaborative brainstorming with Staff to support a viable pathway forward following this unresolved docket.

As a result of the UM 1765 conversations, Staff recommended collecting no more than 0.625% of gross revenues for its low-income weatherization programs. This amount is a close equivalent to electric utilities' collections for low income weatherization plus a .025% premium for the higher costs of serving rural areas. This methodology, 0.625% of gross revenues, gave Cascade a combined 2017 OLIEC and CAT budget of $361,627. It was at this time that Cascade simultaneously filed Advice No. O16-10-02 which established CAT as a permanent program, added performance parameters, and addressed Staff's questions.

Over the life of the OLIEC program, from 2006 through 2016, 570 homes have been weatherized saving an estimated annual total of 86,700 therms. Resulting payments to our partner CAP agencies have totaled $1,488,804 for weatherization measures with payments for agency administration totaling $128,025; CAT program delivery of $125,510; and CNGC admin in the amount of $84,313.

Based on actual program achievements since the beginning of the OLIEC program, and subsequent successes resulting from the CAT, the Company projects approximately 50 homes will be served each year if funds are maintained around the $361,627 level by Staff, and the Agencies are able to maintain an average per-home cost of $6,800. It is important to note that based on pilot activities, it is likely the Agencies would be able to serve around 100 homes each year, if funded at full capacity.

Load Management Programs

The Company also manages load by offering interruptible service, Schedule 177 in Oregon and Schedule 577 in Washington. Customers receiving interruptible service are subject to service curtailment orders during peak usage events. During curtailment events, interruptible customers reduce their consumption, thus reducing the system peak demand. Service for interruptible customers is curtailed during extreme events. The Company does not plan for interruptions or decrement its load forecast for curtailment events.

Environmental Policy and Legislation

Cascade Natural Gas evaluates the impact of a range of externalities, including CO_2 emissions prices, cost adders, and supply costs. The Company also examines other influences with potential impacts to the delivery of cost-effective DSM efforts such as code changes, cost-effectiveness exemptions, and changes in avoided cost and valuation methodologies.

Currently, several regulatory and legislative developments have potential impacts on the demand-side management portion of the IRP. To the best extent possible, these potential impacts have been incorporated into the Oregon DSM projections.

Since the last planning cycle, Cascade has monitored the following legislation, campaigns, and other external actions with the potential to influence natural gas use, and DSM projections, in the States of Washington and Oregon:

National

- National Standard Practice Manual
  The National Efficiency Screening Project, and E4TheFuture have developed the first National Standard Practice Manual (NSPM). This document which expands upon the California Standard Practice Manual and creates a new pathway for evaluating the cost-effectiveness of utility-run conservation activities.

  The manual has its roots in the traditional tests used to assess cost-effectiveness such as the Total Resource Cost (TRC) and Utility Cost Test (UCT), but introduces the Resource Value Test (RVT), a methodology that allows regulators to select the core costs and benefits they wish to assess when determining the cost-effectiveness of utility-run conservation efforts.

  If adapted by the OPUC, this methodology could have significant impacts on overall availability of cost-effective conservation measures offered to Cascade Natural Gas customers. For example, if Oregon regulators decided to include Public Health Impacts or Participant Impacts, this would potentially alter the cost-benefit ratios of measures within the DSM programs operated for the Company. Furthermore, if recommendations regarding discount rates and portfolio-level valuation were followed, the amount of cost-effective conservation could potentially increase, and thus raise the Company's overall DSM achievements.

- Clean Power Plan
  The federal Clean Power Plan (CPP), requiring existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions, is being reevaluated by the EPA. The EPA is reviewing the CPP for consistency with the Executive Order issued on Promoting Energy Independence and Economic Growth and, if appropriate, the EPA will publish for notice and comment proposed rules to suspend, revise or rescind the CPP. The DC Circuit Court has ordered the Clean Power Plan litigation to be placed in abeyance as the EPA reevaluates the rule.

- EPA Report on Hydraulic Fracturing for Oil and Gas
  In 2016, the EPA issued a report on hydraulic fracturing for oil and gas. Anticipated environmental impacts were documented, but were overall inconclusive. There were gaps in the data represented, and estimates contained a high degree of uncertainty. Cascade has determined that there are no immediate impacts of fracking that need to be addressed at this time.

Oregon

- Cap and Invest
  The Oregon State Legislature continues to consider a cap and invest-style approach to carbon regulation that would be similar to SB 1070, introduced during the 2017 Regular Session. Although the bill was not approved at that time, stakeholders are working in earnest to develop a revised version of this bill. Clean energy jobs work groups are being held from September through November 2017 with the goal of creating a revised bill with a high likelihood of passing through the legislature.

- Bend Climate Action Resolution
  On September 7, 2016, the Bend City Council passed a Climate Action Resolution. The document is primarily aspirational but identifies a pathway for carbon reductions in the region. The resolution establishes climate action goals consistent with the international goal of limiting the global average temperature increase to less than two degrees Celsius above pre-industrial levels. To achieve this goal, the City intends to be guided and directed by Climate Action Plans; establish partnerships with local governments and other interested entities; and take a phased approach to achieving long-term solutions.

  The City aspires to reduce its carbon dioxide emissions in its own facilities and operations to achieve carbon neutrality by 2030. It seeks to purchase verifiable carbon offsets from Central Oregon and the Pacific Northwest. Its goal is to reduce its fossil fuel use by 40% by 2030, and by 70% by 2050. Fossil fuel use from 2010, or more recent years, will be used to establish a baseline.

  In addition, the City seeks to reduce the emissions of all businesses, governmental, and non-governmental organizations by 40% by 2030, and by 70% by 2050.

  At this time, it is the Company's understanding that the resolution has been adopted, but not yet implemented.

- Renewable Energy Goals
  Portland has developed a 100% renewable goal. The city proposes to go 100% renewable energy by 2035, and 100% economy wide by 2050. Renewable energy includes energy derived from wind, solar, existing and low-impact hydro, geothermal, biogas, and wave technology sources. Similar goals are also under consideration in Hillsboro, Milwaukie, and Beaverton, Oregon. While each of these communities is outside of Cascade's service area, it is important to keep apprised of such targets in the event that they are adapted in areas served by the Company.

- Gas to Electric Fuel-Switching
  The Cities of Ashland and Eugene have adopted energy action plans to help reduce carbon emissions. As a result of the Ashland Climate and Energy Action Plan, and the Community Climate and Energy Action Plan in Eugene, the Ashland Municipal Electric Utility and Eugene Water and Electric Board are reversing course on the value of the direct use of natural gas for space and water heating, and are considering potential fuel switching from natural gas to electric heat pump technology. Ashland and Eugene plan to begin with the use of renewables for electric generation before aggressively pursuing switching to low carbon and non-carbon fuels.

- HB3711 Moratorium on Hydraulic Fracturing for Oil and Gas Exploration and Production
  HB 2711 would prohibit hydraulic fracking in Oregon with a moratorium that would be in effect until December 31, 2026. Exceptions would have been made to drilling for natural gas storage wells, geothermal wells and geothermal energy, and coal bed methane extraction wells. This passed through the House, but not through the Senate.

Washington

- Carbon Tax
  Several carbon tax bills have recently circulated in the state of Washington including SB 5127, HB 1646, SB 5385, CP-17, SB 5930, S-2861.1, H-2822.1. These included carbon tax schedules ranging from a starting cost of $15/ton to $25/ton and increasing upwards over time. Cascade is monitoring these bills, and other actions closely, as they would impact the cost of the natural gas to customers. There is also current movement by several environmental stakeholders to put a price on carbon, petroleum, natural gas, electricity, and stationary sources in Washington.

- Deep Decarbonization
  Governor Inslee's office released a study in consideration of deep decarbonization, or emissions reductions required to curb a global temperature increase below two degrees Celsius. The study envisions replacing the entire natural-gas pipeline infrastructure with biomethane, synthetic natural gas, and hydrogen.

- Clean Air Rule
  Cascade continues to evaluate options for compliance with the Clean Air Rule.

SECTION 7

RESOURCE INTEGRATION

Overview

Resource integration is the last step in Cascade's IRP process. It involves finding the least cost mix of demand and supply side resources given the forecasted load requirements of the core customers. The tool used to accomplish this task is a computer optimization model known as SENDOUT®.

SENDOUT® is very powerful and complex. It operates by combining a series of existing and potential demand side and supply side resources, and optimizing their utilization at the lowest net present cost over the entire planning period for a given demand forecast. SENDOUT® permits the Company to develop and analyze a variety of resource portfolios quickly, to determine the type, size, and timing of resources best matched to forecast requirements.

Key Points

- Cascade utilizes SENDOUT® to find the optimal solve for forecasted resource deficiencies, as well as alternative portfolios.
- Once a solution is found under expected conditions, the candidate portfolio is stress-tested through stochastic and deterministic scenarios using Value at Risk (VaR) analysis.
- The optimal portfolio includes a combination of incremental transportation on GTN and NWP.
- Without incremental resources, Cascade's first material deficiency occurs in 2020.
- With incremental resources, all forecasted deficiencies are eliminated, at costs that are within Cascade's VaR limit.

Supply Resource Optimization Process

- **Step 1: As-Is Analysis**
  - Cascade began its optimization process by running a deterministic analysis of its existing resources with a three-day peak event. This allowed the Company to uncover the timing and quantity of resource deficiencies. Once the resource need was identified, Cascade utilized its market intelligence to identify all potential options to solve for the projected shortfall.

- **Step 2: Introduce Additional Resources**
  - Once shortfalls were identified, Cascade utilized SENDOUT® to derive a diverse selection of potential portfolios to eliminate the deficiency. This was done through a deterministic analysis of the alternative resources. For the 2018 IRP, Cascade tested six potential portfolios. Table 7-1 groups these portfolios by the source of each resource.

Table 7-1: Breakdown of Scenarios Modeled

	GTN	No GTN
NWP	• ALL-IN	• NWP Only • NWP Only w/ Storage
No NWP	• GTN Only • GTN Only w/ Storage	• Only Storage

- **Step 3: Stochastic Analysis of All Portfolios Under Existing Conditions**
  - Once Cascade selected its portfolios, each one was tested stochastically. Each portfolio was run through a 200 draw Monte Carlo weather simulation under normal weather, growth, and pricing. The Company recorded the total system cost and unserved demand of each draw, as these are the metrics used to rank the portfolios.

- **Step 4: Ranking of Portfolios**
  - Cascade took the unserved demand and total system cost of all draws in each portfolio and calculated the mean and Value at Risk (VaR) of the portfolios. For its modeling purposes, the Company defines VaR as the 95th percentile of unserved demand and total system cost. This is considered a reasonable worst-case scenario for risk analysis. Cascade ranked its portfolios by first giving preference to any portfolio that fully solved for unserved demand in both stochastic and deterministic analysis. After that, portfolios were ranked based on mean total system cost, while penalizing any portfolio with an excess VaR. Cascade believes the top ranked portfolio is the one with the best combination of cost and risk for Cascade and its customers. This is now called the Candidate Portfolio until it has passed a rigorous scenario and sensitivity analysis.

- **Step 5: Stochastic Scenarios of Candidate Portfolio**
  - Cascade created eight different scenarios to stochastically test its candidate portfolio. These scenarios, which are detailed in table 7-2, measure how the portfolio performed in high and low growth environments, as well as various restrictions related to storage availability. In each scenario, the portfolio was run through a 200 draw Monte Carlo weather simulation and the total system cost of each draw was recorded.
  -

- **Step 6: Scenario Analysis of Candidate Portfolio**
  - Cascade took total system cost of all draws and calculated its mean and VaR of each scenario. Each VaR was compared to the Company's VaR limit, which was set by Cascade's Gas Supply Oversight Committee (GSOC) and was equal to 1.25 times the mean total system cost of the portfolio under expected conditions[1]. If the VaR in any scenario exceeded this limit, that portfolio was rejected and the next highest ranked portfolio became the new Candidate Portfolio for scenario analysis. If the VaR of all scenarios did not exceed this limit, the portfolio passed scenario testing and moved to sensitivity testing.

- **Step 7: Sensitivity Testing of Candidate Portfolio**
  - Cascade created nine difference pricing environments to stochastically test its candidate portfolio. These sensitivities, which are detailed in Table 7-2, measure how the portfolio performed in high and low price situations, as well as with a range of adders related to carbon legislature. In each sensitivity, the portfolio was run through a 200 draw Monte Carlo NYMEX price simulation, and the total system cost of each draw was recorded.

- **Step 8: Sensitivity Analysis of Candidate Portfolio**
  - Cascade took total system cost of all draws and calculated the mean and VaR in each sensitivity. Each VaR was compared to the Company's VaR limit, which is set by GSOC and was equal to 1.25 times the mean total system cost of the portfolio under expected conditions. If the VaR in any sensitivity exceeded this limit, that portfolio was rejected and the next highest ranked portfolio became the new Candidate Portfolio for scenario analysis. If the VaR of all sensitivities did not exceed this limit, the portfolio passed scenario testing and could be confirmed as Cascade's Preferred Portfolio. Figure 7-1 displays this process as a flow chart.

[1] By Corporate Policy, Cascade does not engage in speculation and therefore considers VaR limits conservatively. Similar to the development of a stop-loss limit, Cascade looked at the prevailing market bid price (i.e. the highest price for which parties are willing to buy the commodity at a given point in time), compared to the lowest bid price over the approved buying period. Consistent with PGA guidelines under UM-1286, Cascade used 60-day NYMEX pricing. At the time GSOC approved the 2017 portfolio was approved (based on a three-year design), running high bid running NYMEX was $3.568. The low bid price was $2.682, resulting in VaR tolerance of 1.2483184, which was rounded to 1.25 for modeling purposes. Cascade will be implementing more robust risk management strategies in 2018. Cascade expects VaR limit determination to be a discussion item during the Company's next IRP public process.

Figure 7-1: Preferred Portfolio Selection Flow Chart

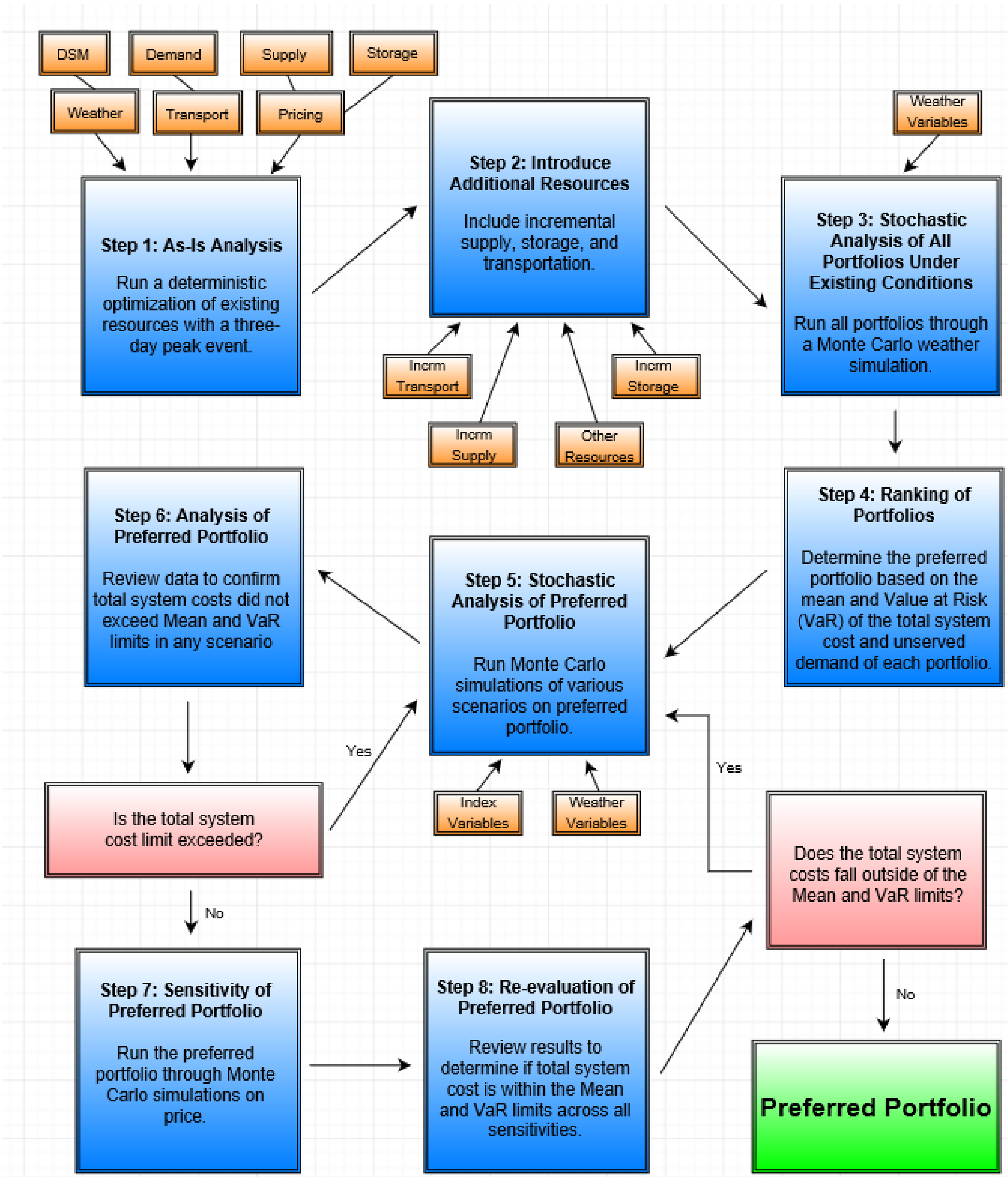


Table 7-2: Breakdown of Scenarios & Sensitivities Modeled

Scenarios and Sensitivities		Assumptions				
		Growth	Weather	Price	Constraints	First Year Unserved
All-In		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	None	2026
As-Is		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only models current resources	2020
GTN Only		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only GTN resources available	2018
GTN Only w/ Storage		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only GTN resources and all storage available	2018
NWP		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only NWP resources available	2020
NWP w/ Storage		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only NWP resources and all storage available	2020
Storage Only		Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only storage resources available	2020
Price	High	Medium Load Growth	Average Weather with Peak Event	High Gas Price Environment	None	2027
	Base	Medium Load Growth	Average Weather with Peak Event	Expected Gas Price Environment	None	2027
	Low	Medium Load Growth	Average Weather with Peak Event	Low Gas Price Environment	None	2027
Carbon Adder	0.1	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with 10% Adder for Unknown Regulatory Impacts	None	2027
	0.2	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with 20% Adder for Unknown Regulatory Impacts	None	2027
	0.3	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with 30% Adder for Unknown Regulatory Impacts	None	2025
Per Ton	10	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with $10 per ton Carbon Tax	None	2027
	20	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with $20 per ton Carbon Tax	None	2025
	30	Medium Load Growth	Average Weather with Peak Event	Medium Gas Price Environment with $30 per ton Carbon Tax	None	2025
Limit Storage	Limit JP	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only 25% of JP storage available	2027
	Limit Ply	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only 25% of Plymouth storage available	2037
	Limit Both	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	Only 25% of both JP and Plymouth available	2025
No Storage	No JP	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	No JP storage available	2027
	No Ply	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	No Plymouth storage available	2027
	No JP and No Ply	Medium Load Growth	Average Weather with Peak Event	Medium Pricing Environment	No storage available	2018
Growth	Low Growth	Low Load Growth	Average Weather with Peak Event	Medium Pricing Environment	None	2035
	High Growth	High Load Growth	Average Weather with Peak Event	Medium Pricing Environment	None	2024

While Section 11 includes a full Glossary, terms related to Table 7-2 are shown below for convenience.

Glossary of Terms Used in Table 7-2

Average Weather with Peak Event. The weather pattern was modeled using historical weather data in each of Cascade's climate zones for the past 30 years. In addition, a design peak day was inserted on December 21st of each year to allow for conservative forecasting to model the coldest day in Cascade's system over the past 30 years.

Low Load Growth. Low growth scenarios were created by examining the low end of the 95% confidence intervals of Cascade's demand forecast, as mentioned on page 3-8.

Medium Load Growth. Cascade applied the expected growth rates gathered from Woods & Poole, as mentioned on page 3-8 for the expected growth scenario.

High Load Growth. High growth scenarios were created by examining the high end of the 95% confidence intervals of Cascade's demand forecast, as mentioned on page 3-8.

Low Gas Price Environment. Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from a number of sources over the 20-year planning horizon. Prices were then reduced by 6% at all markets (i.e., NYMEX, Sumas, Rockies, AECO) to simulate a low pricing environment over the 20-year period.

Medium Gas Price Environment. Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from a number of consultants over the 20-year planning horizon.

High Gas Price Environment. Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by 5% at all markets to simulate a high pricing environment over the 20-year period.

Average Price with 10% Adder. Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from a number of sources over the 20-year planning horizon. Prices were then increased by 10% at all markets to simulate the impact of unforeseen environmental conditions.

Average Price with 20% Adder. Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by 20% at all markets to simulate the impact of unforeseen environmental conditions.

Average Price with 30% Adder. Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by 30% at all markets to simulate the impact of unforeseen environmental conditions.

Average Price with $10/Ton Tax. Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from a number of sources over the 20-year planning horizon. Prices were then increased by a $10/metric ton carbon tax at all markets to simulate the impact of potential carbon legislature.

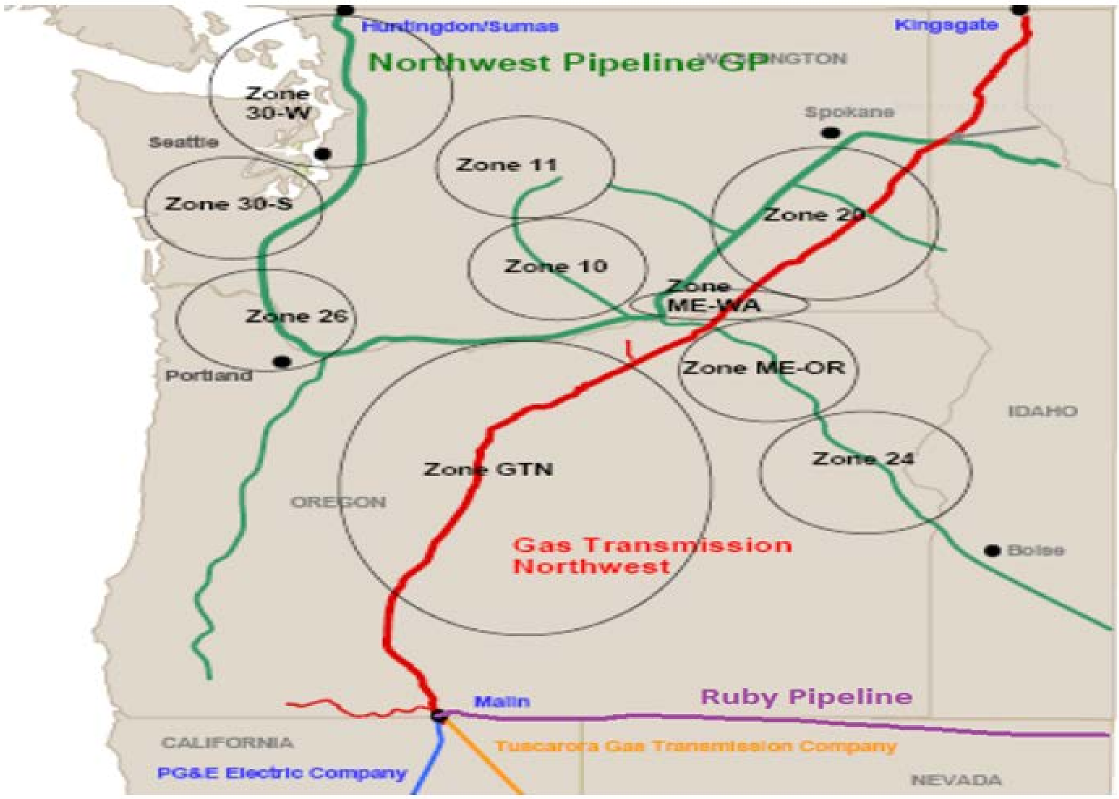
Average Price with $20/Ton Tax. Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by a $20/metric ton carbon tax at all markets to simulate the impact of potential carbon legislature.

Average Price with $30/Ton Tax. Price was modeled using Cascade's price forecast, which was derived by weighting the forecast of a number of sources over the 20-year planning horizon. Prices were then increased by the cost of a $30/metric ton carbon tax at all markets to simulate the impact of potential carbon legislature.

Planning and Modeling

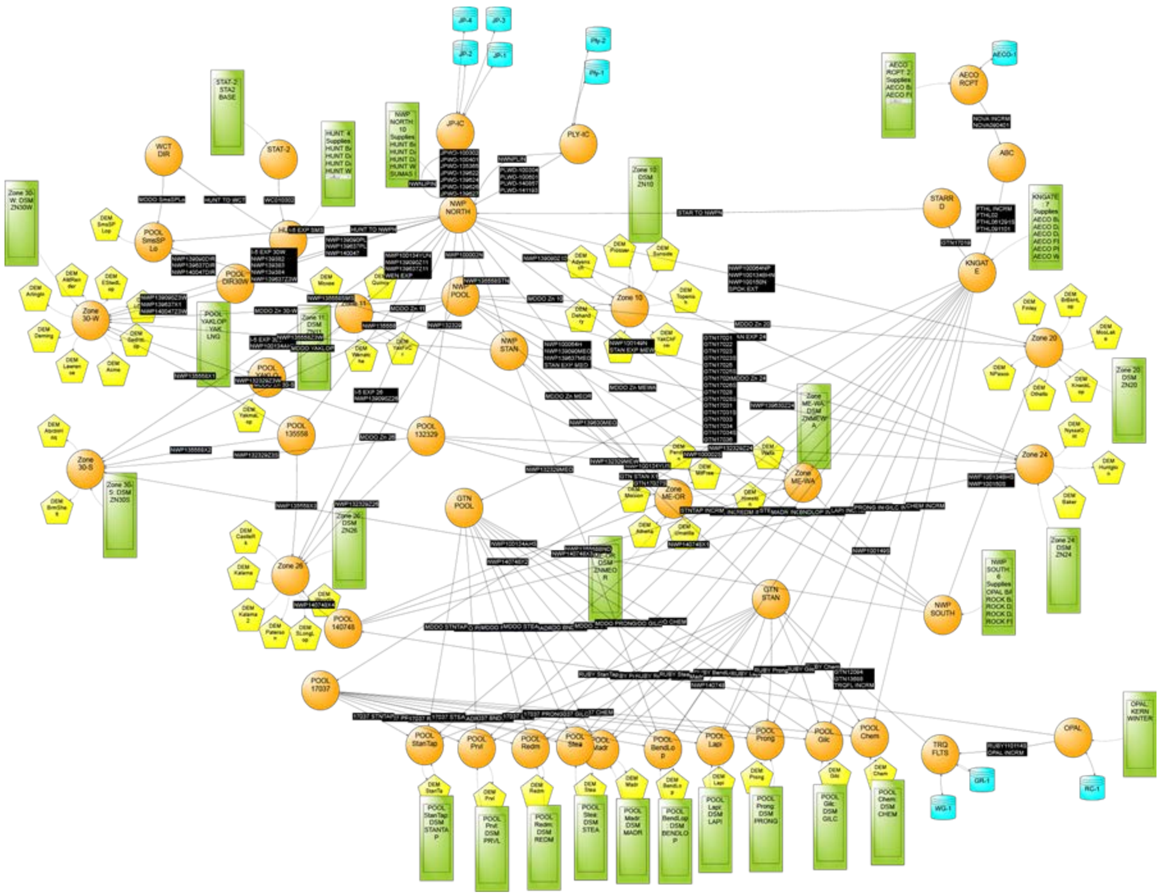
SENDOUT® has broad capabilities that allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Beginning with the 2008 IRP, Cascade expanded its modeling from the district level to modeling the system grouped by the various pipeline zones. Figure 7-2 shows the location of these pipeline zones. These pipeline zones reflect Cascade's customers being served from either Northwest Pipeline LLC (NWP) or Gas Transmission Northwest (GTN) interstate pipeline facilities.

Figure 7-2: Pipeline Zones Used in this IRP



With the in-house load forecast model (LFM) application, which is discussed in detail in Section 3, Demand Forecast modeling dives into an even more granular level. This IRP takes more of a citygate view, which allows Cascade to take a deeper view of capacity shortfalls and potential constraints. A copy of the network diagram is shown in Figure 7-3. The network diagram is provided for illustrative purposes to emphasize the difficulties in configuring the model to best replicate Cascade's complex system rather than being provided for its readability. (An expanded view of this graphic is available upon request.)

Figure 7-3: SENDOUT® Network Diagram of Cascade's System



Tools Used

Because SENDOUT® utilizes a linear programming approach, its results are considered deterministic. For example, the model calculates the exact load and price for every day of the planning period based on inputs and can, therefore, minimize costs in a way that, by definition, would not likely occur in a highly dynamic operating environment. Therefore, it is important to acknowledge that linear programming analysis provides helpful but not perfect information to guide decisions.

Since decisions are made in the context of uncertainty about the future, Cascade uses SENDOUT® functionality that facilitates the ability to model gas price and load uncertainty (driven by weather) into the future. SENDOUT® utilizes a Monte Carlo approach in combination with the linear programming approach in SENDOUT®. The Monte Carlo modeling capability provides supplemental information to decision-makers under conditions of uncertainty. This tool continues to enhance the robustness of the Company's long-term resource planning and acquisition activities.

Resource Optimization Output and Analysis Reports

After the model run is performed and SENDOUT® selects the optimal set of resources from the available portfolio, output reports are generated. SENDOUT® provides an assortment of Input and Output reports that it can generate, provided they are selected prior to the optimization run. SENDOUT® offers dozens of separate input reports that summarize various items such as demand inputs, the resulting forecast, temperature patterns as well as supply, storage, and transportation resource inputs. These reports verify that the information supplied to SENDOUT® is being accurately interpreted by the model.

The results of the optimization process are provided in the dozens of output summary reports. These reports summarize various aspects of the optimal portfolio resource size and selection as well as cost and utilization over the planning period. For purposes of this discussion, certain key output reports will be summarized below.

Key Output Report - Cost and Flow Summary

The Cost and Flow Summary Report consolidates a number of very informative aspects of the optimization run. The report provides a breakdown of portfolio costs on a yearly basis, unit cost detail, as well as a total planning period basis, in several different formats. For example, an aggregate portfolio cost total is provided for comparison between years, as well as between various optimization runs, if the analyst is attempting to compare the impact that one or more resources can have on the portfolio. This total portfolio cost figure is also broken down into supply, storage and transportation cost summaries on both a yearly and planning period basis.

The report also contains the Resource Mix summary. This summarizes SENDOUT® decisions regarding the sizing and optimal mix of incremental resources, which determines whether one or many different types of resources should be considered for inclusion in the total resource portfolio.

Key Output Report - Month to Month Summary

While the Cost and Flow summary provides an indication of individual resource utilization, the Month to Month summary allows greater examination of how SENDOUT® utilizes each resource. The user can determine if the particular type of resources presented to SENDOUT® are being utilized as envisioned or whether other types of resources would more closely match requirements. For example, as has been done by Cascade, the analyst may offer annual supply contracts to SENDOUT® to address load growth over the planning period. The analyst can examine this report to determine if SENDOUT® uses these supplies throughout the year or only occasionally. If SENDOUT® utilizes this resource on a short-term basis during the winter, the analyst can introduce seasonal resources to SENDOUT® to determine whether it would choose them over the annual supplies already available in the portfolio.

SENDOUT® also presents monthly information in other specific reports. For example, the supply information provided in this Month to Month report is also available in greater detail in the Supply Summary Report. The same is true with the Transportation Summary Report and the Storage Summary Report. SENDOUT® also offers monthly supply utilization information in a Load Factor Summary Report, which some analysts may prefer to use in their approach to analyzing the SENDOUT® results.

Key Output Report - Supply vs. Requirements

The Supply vs. Requirements report compares a particular forecast's monthly demand requirement quantity against the optimal portfolio's various supply quantities. This shows supply utilization as well as determines whether the supply portfolio quantities are sufficient to meet demand. If an insufficiency exists, the report isolates the shortfall by month as well as the location of the Company's demand requirement. With this information, the Daily Unserved Demand reports determine if a pattern exists with respect to the shortfall. For example, if the daily report indicates that the shortfall occurs on the peak day the analyst could turn to the Peak Day Reports to determine if the shortfall is supply or transportation related. If the shortfall occurs on a number of days surrounding the peak or at other times during the year, the analyst can turn to the Daily Supply Take and Daily Transport Flow reports to determine whether the portfolio is constrained by supply availability or transport capacity on those particular days.

Key Output Reports - Custom Report Writer

Ultimately, the availability and interpretation of information gained through SENDOUT® output reports contribute to developing better resource portfolios. SENDOUT® output report(s) contains vast amounts of information, which may overwhelm the casual observer. Therefore, SENDOUT® offers the user a Custom Report Writer (or Report Agent) module, which can isolate certain information contained in the various output reports and improve the analysis activity. Report Agent provides the user a menu of report information sources from which to choose specific items. The user has the option of viewing or downloading the information into spreadsheets or databases. Provided the information is available, the analyst can readily access specific items, which simplifies the data acquisition process if further analysis is desired. While the report writer is a useful tool in this regard, not all SENDOUT® output information can be accessed through this module.

Key Inputs

Individual transportation segments, storage, supply and demand side resources, both existing and potential, are targeted to demand segments representing the citygates connected to the system and the various classes of core customers behind those gates. This level of precision allows SENDOUT® to consider each resource on an individual basis within the portfolio while also recognizing where physical system limitations exist. Resource characteristics such as a supply contract's daily delivery capability, minimum take requirements, maximum daily transport capability by individual segment, storage inventory limitations and withdrawal, and injection curve characteristics are part of each resource's basic model inputs. The ability to model resources in this fashion allows SENDOUT® to tailor the optimization within envisioned constraints and ensures that the model's optimal solution can work under anticipated operating conditions.

The optimization process compares a portfolio of resources against a specific demand requirement. SENDOUT® generates a daily demand forecast by combining base load and temperature sensitive usage factor inputs with a specified daily temperature pattern input. For IRP purposes usage factor inputs were specifically developed under high, medium, or low demand profiles culled from Cascade's in-house load forecast model. Daily temperature patterns are available as either design or average weather. Due to the complexity of the SENDOUT® application, the model has some combined demand areas compared to the load forecast model. Therefore, both usage factor and temperature pattern inputs from the LFM may be slightly adjusted within SENDOUT® on an area specific basis without creating any material difference in the load demand.

In SENDOUT®, each supply contract requires a Maximum Daily Quantity (MDQ) input to establish its specific delivery capabilities. Review of the daily, annual, monthly, or seasonal minimum utilization of the contract is required. Maximum take quantities can also be established on either an annual, monthly, or seasonal basis. The Commodity Rate input can reflect either a known price, in the case of a fixed cost contract, or index prices, if the user has established a representative index as a separate input item. Several fixed and variable cost rate inputs are also available for establishing separate contract cost items, if necessary. Most of the gas supply options discussed above are also available as transportation inputs.

Penalty Rates on an annual, seasonal, monthly or daily basis are needed if either minimum or maximum utilization requirements are required or desired. The penalty rate can be any amount desired or a specific amount if known. The intent of the penalty option is to direct SENDOUT® to adhere to whatever minimum or maximum characteristic is specified.

Resource Mix is one of the more powerful and highly desirable input tools available in the model. By toggling on Resource Mix and providing an MDQ maximum and minimum, the user directs SENDOUT® to appraise the supply contract, on a total cost basis, against all other supply resources available within the portfolio. Under Resource Mix, SENDOUT® will determine whether the resource is desirable within the portfolio and at what MDQ size, within the MDQ Maximum and Minimum, the resource should be made available within the portfolio. This aspect of SENDOUT® is crucial to the evaluation of potential resources, as the Company conducts its resource planning, appraisal, and acquisition activities.

In addition to most of the items discussed above, storage resources have additional input considerations. Instead of Daily MDQ inputs, the analyst establishes inventory maximums and/or minimums. If monthly inventory levels are to change over the years or within a year, SENDOUT® allows the analyst to establish that target. Injection and withdrawal capability, as well as the period within the year that each is available, are also input decisions.

A unique feature of SENDOUT® storage input is the Storage Volume - Dependent Deliverability or SVDD Tables. This input item allows the user to tailor injection and withdrawal rates as either a line or step function based upon whether the facility has varying operating pressure constraints as the injection or withdrawal activity is conducted. The analyst can also establish whether inventory exists at the beginning of the planning period, and whether various prices and specific quantities exist at that time. SENDOUT® provides the analyst with five separate volume and price levels to reflect existing inventories.

Finally, SENDOUT® allows for input of a penalty rate for unserved demand. Cascade uses this functionality to give SENDOUT® a way to prioritize which rate tariff to serve when demand is higher than then resources available to serve that demand. These penalties are always higher than the cost of any incremental resources, as SENDOUT® should always elect to purchase these resources versus leaving demand unserved. Residential customers are always assigned the highest penalty. This tells SENDOUT® to prioritize serving these customers above all others. Commercial customers have the next highest penalty, followed by Commercial/Industrial customers, and finally Industrial customers. It is important to note the customers on an interruptible tariff do not have a penalty assigned to leaving their demand unserved. This allows SENDOUT® the flexibility to serve the demand of these customers when possible, while making sure not to purchase additional resources if they will only be used to serve interruptible demand.

Decision Making Tool

Analysis of optimization model results and other operational and contractual constraints allows Cascade to make more informed resource decisions. The IRP optimization model output and Monte Carlo simulation analysis provide the quantifiable output from numerous model inputs. The model does not prescribe the ultimate resource portfolio. It can only calculate the least cost set of resources given their specific pricing and quantifiable constraint characteristics. However, many other resource combinations may be available over the planning horizon. Therefore, Cascade must include subjective risk judgments about unquantifiable and intangible issues related to resource selections. These include future flexibility, supplier deliverability risk, pipeline(s) risk, financial risk to the utility and its customers, operational constraints, regulatory risk, etc. The risk judgments are combined with the quantitative IRP analysis to form the actual resource decisions.

Resource Integration

The following subsections summarize the analysis of the preceding sections bringing together the demand forecast, existing supply and demand side resources and potential alternative resources to develop the 20-year, most reasonably priced portfolio.

Demand Forecast

As explained in Section 3, Demand Forecast, load growth across Cascade's system through 2037 is expected to fluctuate between 1.50% and 1.65% annually after smoothing the leap year anomaly. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at a rate near 1.4-1.6% annually, while industrial expects a growth rate of around 1.9. Load across Cascade's two-state service territory is expected to increase 34.6% over the planning horizon, with the Oregon portion outpacing Washington at 41.6% versus 32.2%.

Long-Term Price Forecast

In Section 4, Supply Side Resources, Cascade discusses how the 20-year price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. Since pricing on the market is heavily influenced by Henry Hub prices, the Company closely monitors this market trend. The fundamental forecasts of Wood Mackenzie, the Energy Information Administration (EIA), the NPCC, and trading partners are resources for the development of Cascade's blended long-range price forecast. Since the Company's physical supply-receiving areas (Sumas, AECO, and Rockies) are at a discount to Henry Hub, the Company utilizes the basis differential from Wood Mackenzie's most recently available update and compares that to the future markets' basis trading as reported in the public market.

Natural gas prices have fluctuated dramatically over the course of the last ten years. Figure 7-4 shows the history of regional and Henry Hub prices over the past ten years. The Great Recession, the shale boom, environmental concerns around carbon, conservation efforts, and improvements in renewable energy have led to a market with prices as low as they have been in recent history.

Figure 7-5 shows the comparison of ranges of pricing for the planning horizon, including the expected scenario low, medium and high price.

Figure 7-4: Historical Regional Pricing for Past Ten Years

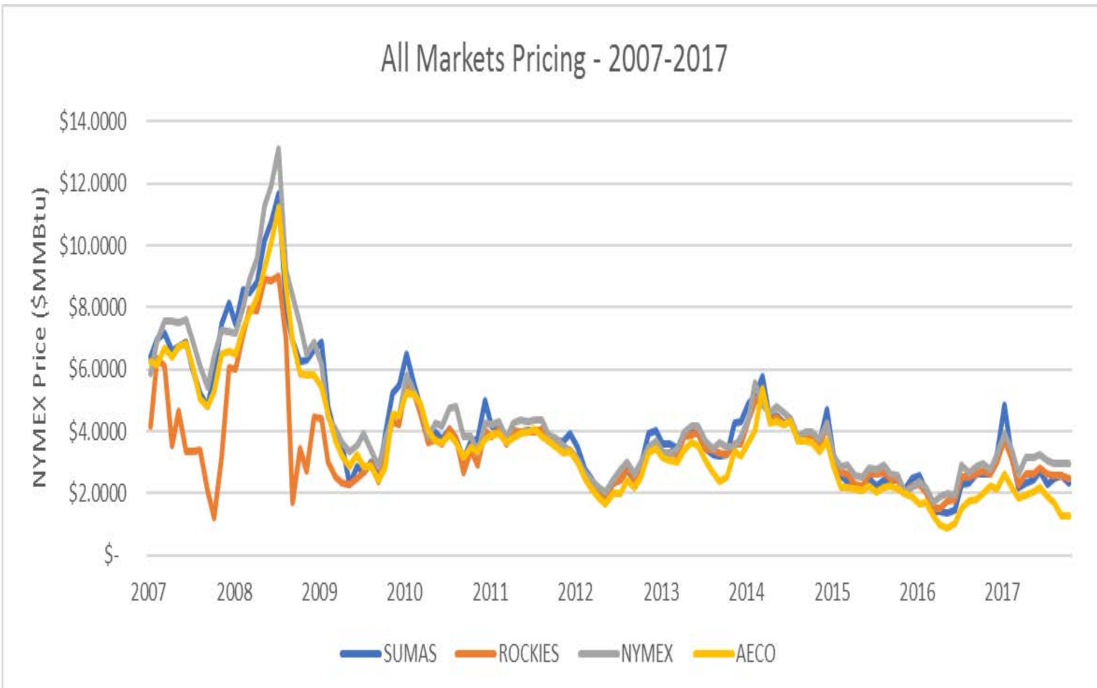
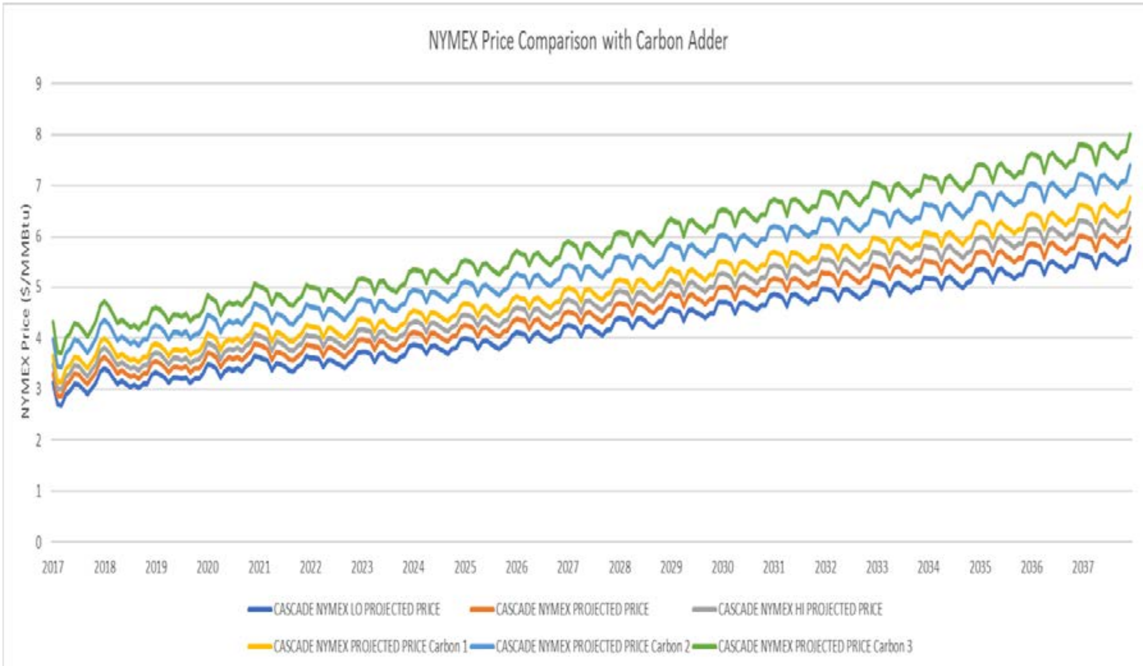


Figure 7-5: NYMEX Annual Price Comparison



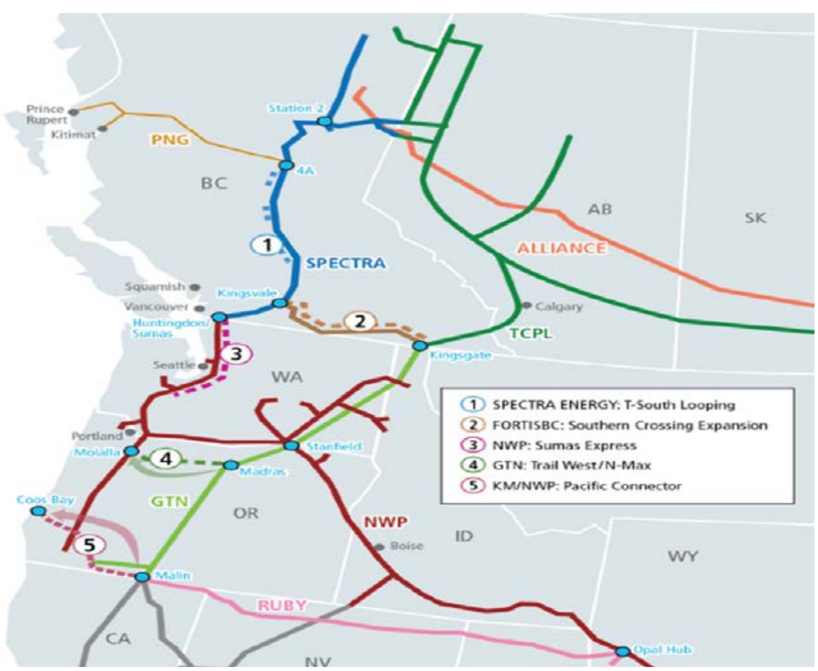
Environmental Adder

As discussed in Section 6, DSM and Environmental Policy, Cascade included a 10% environmental adder in its 2018 IRP's expected scenario 20-year price forecast.

Transportation/Storage

Section 4, Supply Side Resources, describes the range of current upstream pipeline transportation capacity and storage services under contract to serve core customers. Additionally, the Company identified several proposed transportation resources, as seen in Figure 7-6, such as a potential expansion of NWP along the I-5 corridor and acquiring currently unsubscribed GTN capacity that can be used to meet customer growth and address potential capacity shortfalls. The Company also continues to work with NWP to look at re-aligning Cascade's contracted demand rights (Maximum Daily Delivery Obligations, or MDDOs) to citygates with potential peak day capacity shortfalls. The Company also works to use segmenting pipeline capacity as a way to maximize the utilization of Cascade's capacity. These resources plus leasing incremental storage at a number of regional facilities were all considered as a resource mix of possibilities to form the Company's 20-year integrated resource portfolio.

Figure 7-6: Alternative Transportation Resources[2]



2 NWGA Proposed Projects, July 2017

Section 6, DSM and Environmental Policy, describes the methodology used to identify conservation potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of conservation measures on an equivalent basis with supply side resources. For the 2018 IRP the system avoided costs ranges between $0.4349/therm and $1.0393/therm over the 20-year planning horizon. Through the cost-effective use of conservation programs, the Company is able to reduce the load demand that must be met by more costly supply resources, such as a pipeline capacity expansion.

Results

After incorporating these inputs into the SENDOUT® model, Cascade analyzed the demand compared to the existing resources as well as the demand against all the available resources. This served as the foundation for the Company to see what resources are taken to meet system demand with the least cost mix of natural gas supply and conservation. The Company then ran the optimization again removing the resources SENDOUT® did not select from the All-In portfolio. This allowed Cascade to confirm that removing these resources does not impact the amount of served demand. Additionally, this step removes fixed costs associated with the resources not taken so Cascade can arrive at a true total system cost. Table 7-3 provides a snapshot of the potential peak day unserved demand across Cascade's system prior to applying any realignment of delivery rights, transportation contract segmentation or other alternative resources. Table 7-4 displays the same information as Table 7-3, but for Oregon citygates only.

Table 7-3: Load Centers with Potential Peak Day Unserved Demand in Dekatherms– As Is Scenario

Area	2018	2020	2025	2030	2035	2037
Zone 30-S	-	-	1,663	4,450	7,647	8,996
Zone 30-W	-	-	4,042	11,869	20,502	24,166
Bend Loop	-	1,504	8,488	15,835	23,266	26,262
Total	**-**	**1,504**	**14,193**	**32,154**	**51,415**	**59,424**

Table 7-4: Oregon Load Centers with Potential Peak Day Unserved Demand in Dekatherms – As Is Scenario

Area	2018	2020	2025	2030	2035	2037
Bend Loop	-	1,504	8,488	15,835	23,266	26,262
Total	**-**	**1,504**	**8,488**	**15,835**	**23,266**	**26,262**

Because Cascade has more delivery rights than receipt rights, the Company must allocate the delivery rights to match up with receipt capability. First, the Company allocates capacity on transportation contracts that have a single receipt point. Next, Cascade allocates capacity on conjunctive contracts that provide corridor and delivery point flexibility (re-allocation of MDDOs). The Company also gives consideration to critical delivery areas, constrained laterals and maximizing corridor flexibility—longest haul contractual rights.

Analysis of Unserved Demand

By many accounts, the Pacific Northwest will experience significant growth over the 20-year planning horizon. Cascade will need to acquire additional resources to solve for the deficiency caused by this growth. Of note, growth at one of the Company's citygates may cause unexpected shortfalls at other, seemingly unrelated citygates. For example, Cascade's Bremerton-Shelton citygate serves a significant number of residential customers. If that area were to experience rapid growth, existing resources for customers on an interruptible tariff, in Yakima for example, may be realigned to Bremerton-Shelton to serve this increased demand using a transportation contract with a broadly defined receipt point. This would make it appear as though Yakima had experienced the rapid growth, since that is where the shortfall would be appearing, even though this would not be the case in this hypothetical example. Page 3-9 goes into further detail regarding some of the major growth drivers.

Portfolios Evaluated

For the 2018 IRP, Cascade has elected to evaluate six potential portfolios. These portfolios represent a wide variety of potential solutions for Cascade's resource deficiency, with an evaluation of all available resources in the pacific northwest for natural gas. Unlike electric utilities, who have a variety of options for power generation (hydro, wind, solar, etc.), Cascade is limited to a single resource, natural gas, which hinders the scope of potential portfolio analysis. The Company selected these six portfolios after discussions with various stakeholders throughout its technical advisory group process. In future IRPs, Cascade will consider evaluating additional portfolios.

Table 7-5 outlines the key components of each portfolio identified in Table 7-1. SENDOUT® deterministically selects the optimal quantity of each resource based on its Resource Mix functionality. These quantities are then tested stochastically, and ranked in order of unserved demand and total system cost.

Table 7-5: Resource Composition of All Evaluated Portfolios

	All In	Incremental GTN	Incremental GTN & Storage	Incremental NWP	Incremental NWP & Storage	Storage Only
Incremental NGTL	X	X	X			
Incremental Foothills	X	X	X			
Incremental GTN N/S	X	X	X			
I-5 Expansion	X			X	X	
Wenatchee Lateral						
Spokane Expansion				X	X	
Eastern OR Expansion						
Incremental Opal						
Incremental Ruby						
Incremental GTN S/N						
T-South Southern Crossing						
Trails West (Palomar)						
Pacific Connector						
Ryckman Creek Storage			X		X	X
Magnum Storage						
AECO Hub Storage						
Clay Basin Storage						
Gill Ranch Storage						
Mist Storage						
Wild Goose Storage						
Incremental Opal Supply						
Renewable Natural Gas						

Alternative Resources Selected

The SENDOUT® model selected the following resources for the candidate 20-year portfolio. These resources and the quantities and timing that the resources are needed by are summarized in Table 7-6.

Table 7-6: Projected Cumulative Incremental Transport Needed – in Dekatherms

Resource	2018	2028	2037
I-5 Expansion	-	11,926	33,162
Incremental Nova	-	-	36,246
Incremental Foothills	-	-	25,908
Incremental GTN	-	12,836	26,262
Total	**-**	**24,762**	**121,578**

Transport

- Incremental GTN – Allows Cascade to continue to serve customers as the Company's core load grows in citygates that are fed by GTN capacity, specifically around Bend, Oregon, where the Company expects shortfalls. 12,836 dths/day by 2028, escalating to 26,262 dths/day by 2037.
- I-5 Expansion – Allows Cascade to continue to serve customers as the Company's core load grows around the I-5 corridor, specifically in the Sedro-Woolley area. 11,926 dths/day by 2028, escalating to 33,162 dths/day by 2037.
- Incremental NOVA – Provides Cascade with a cost-effective opportunity to move gas from AECO to Kingsgate, versus buying gas at Kingsgate directly. 36,246 dths/day by 2037.
- Incremental Foothills – Provides Cascade with a cost-effective opportunity to move gas from AECO to Kingsgate, versus buying gas at Kingsgate directly. 25,908 dths/day Nov. 2037.

Alternative Resources Not Selected

The SENDOUT® model did not select the following resources for the 20-year portfolio:

Transport

- Incremental Ruby/Turquoise Flats – SENDOUT® determined it was more cost-effective for the Company to acquire unsubscribed transport from GTN to serve the incremental demand these incremental contracts would otherwise serve.
- Wenatchee Expansion – Cascade's market intelligence determined that it would be more cost-effective to acquire incremental NWP capacity along the I-5 corridor while redirecting existing flexible transportation to central Washington.
- Zone 20 Expansion – Cascade's market intelligence determined that it would be more cost-effective to acquire incremental NWP capacity along the I-5 corridor while redirecting existing flexible transportation to eastern Washington.
- Incremental Starr Road – SENDOUT® determined that with Cascade's current price forecast it did not make sense to purchase incremental capacity to move AECO gas from GTN to NWP.
- Eastern Oregon Expansion – Cascade's market intelligence determined that it would be more cost-effective to acquire incremental NWP capacity

along the I-5 corridor while redirecting existing flexible transportation to eastern Oregon.

- T-South Southern Crossing – SENDOUT® determined that based on Cascade's current price forecast it did not make sense to purchase incremental capacity to move in either direction along the Canadian border.
- Trails West (Palomar) – SENDOUT® determined that with Cascade's current price forecast it did not make sense to purchase incremental capacity to move in either direction across central Oregon.

Supply

- Opal Incremental – Since SENDOUT® determined it was best to serve increasing demand through picking up unsubscribed GTN capacity, there was no need to purchase additional gas to move along Ruby.
- Pacific Connector - Cascade's market intelligence determined that at this time, the Pacific Connector would not create a significant enough impact on liquidity at Malin to impact Cascade's modeling.

Storage

- Ryckman Creek, Gill Ranch, Wild Goose, AECO Hub – No incremental storage was selected. None of the storage facilities modeled were cost-effective or led to an increase in served demand. The primary reason appears to be that each storage facility modeled required long-term incremental transportation.

Candidate Portfolio

Using input from the alternative resources selected, SENDOUT® derived a portfolio of existing and incremental resources that Cascade defined as the Candidate Portfolio. This portfolio provides guidance as to what resources should be considered to reduce the unserved demand with the least cost mix of all of the alternatives that the Company has considered. Furthermore, this was derived deterministically assuming average weather with a peak day event, Cascade's average price forecast, and expected growth system-wide. The impact of these resources on both unserved demand and total system cost is shown in Table 7-7, as well as graphically in Figures 7-7 through 7-12.

Portfolio Evaluation

Table 7-7 summarizes the mean and VaR of the total system cost and unserved demand of the portfolios considered. Given Cascade's obligation to serve its customers, portfolios are first evaluated on unserved demand, and then mean total system cost.

Table 7-7: Final Ranking of Portfolios – Mean and VaR

	Total System Cost		Unserved Demand	
Portfolios	Mean ($000)	VaR ($000)	Mean (Mdts)	VaR (Mdts)
All-In	3,730,375	3,761,824	0	0
Incrm GTN	3,605,874	3,636,062	36.04	92.46
Incrm GTN with Storage	3,607,897	3,638,312	36.04	92.46
Storage Only	3,741,640	3,772,235	46.35	86.65
Incrm NWP with Storage	3,763,508	3,794,217	46.06	86.64
Incrm NWP	3,763,540	3,795,170	46.06	86.55

Figure 7-7: Annual Supply Take vs Demand – Candidate Portfolio

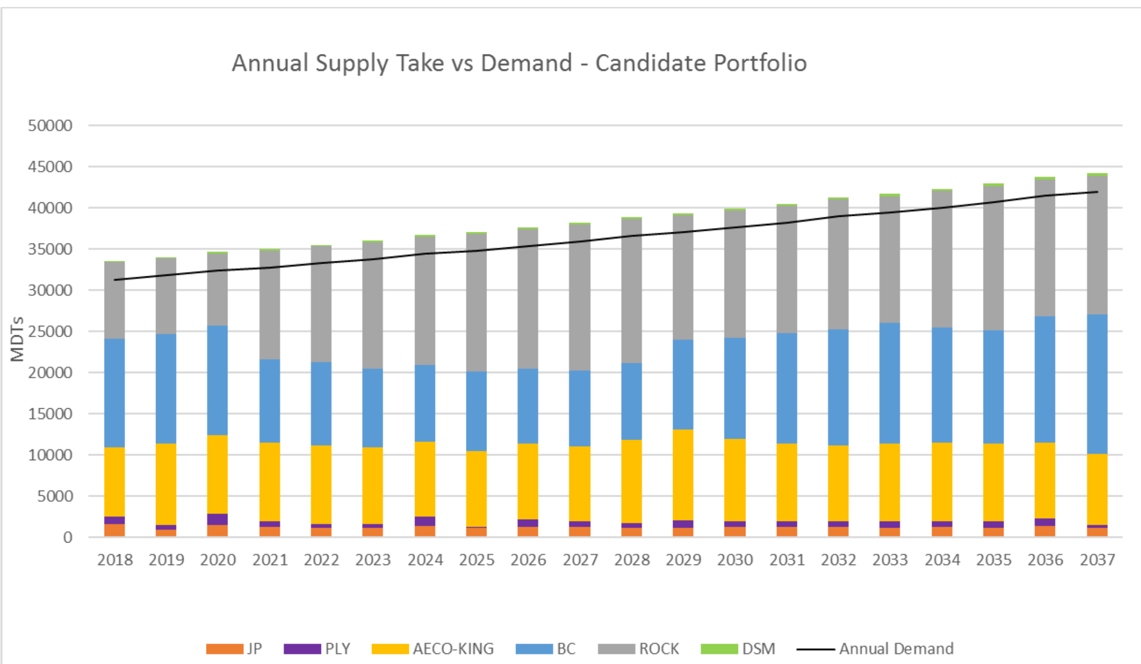


Figure 7-8: Peak Day Supply Take vs Demand – Candidate Portfolio

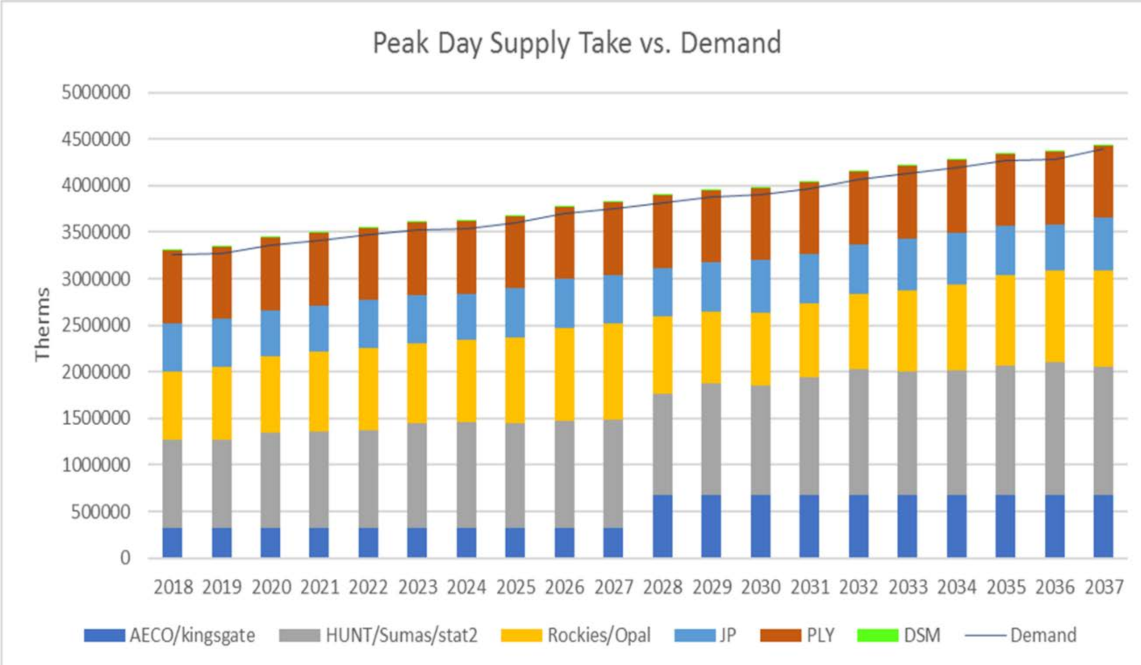


Figure 7-9: Peak Day Transport vs Demand, Incremental Broken Out – Candidate Portfolio

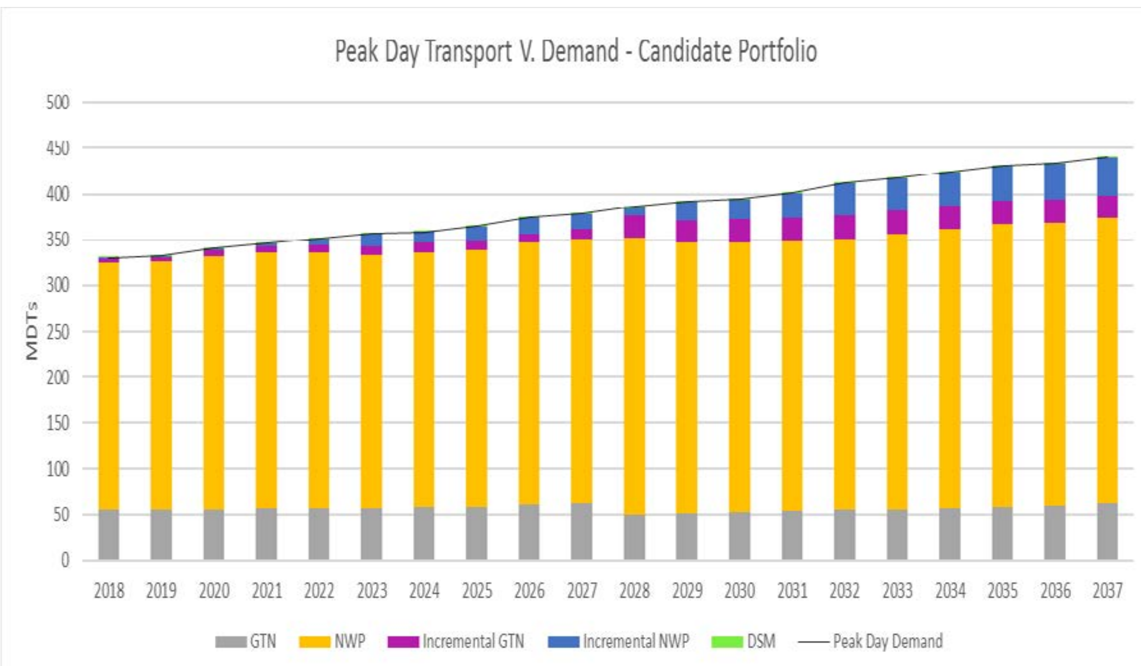


Figure 7-10: Peak Day Incremental Transportation – Candidate Portfolio

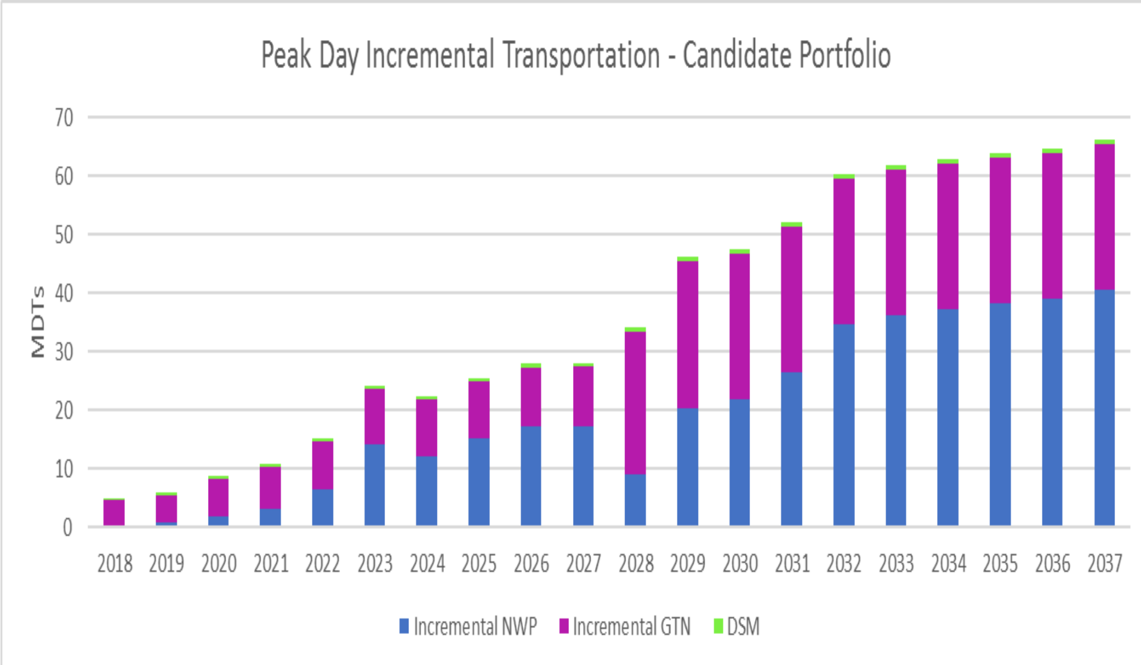


Figure 7-11: Annual Transport vs Demand – Candidate Portfolio

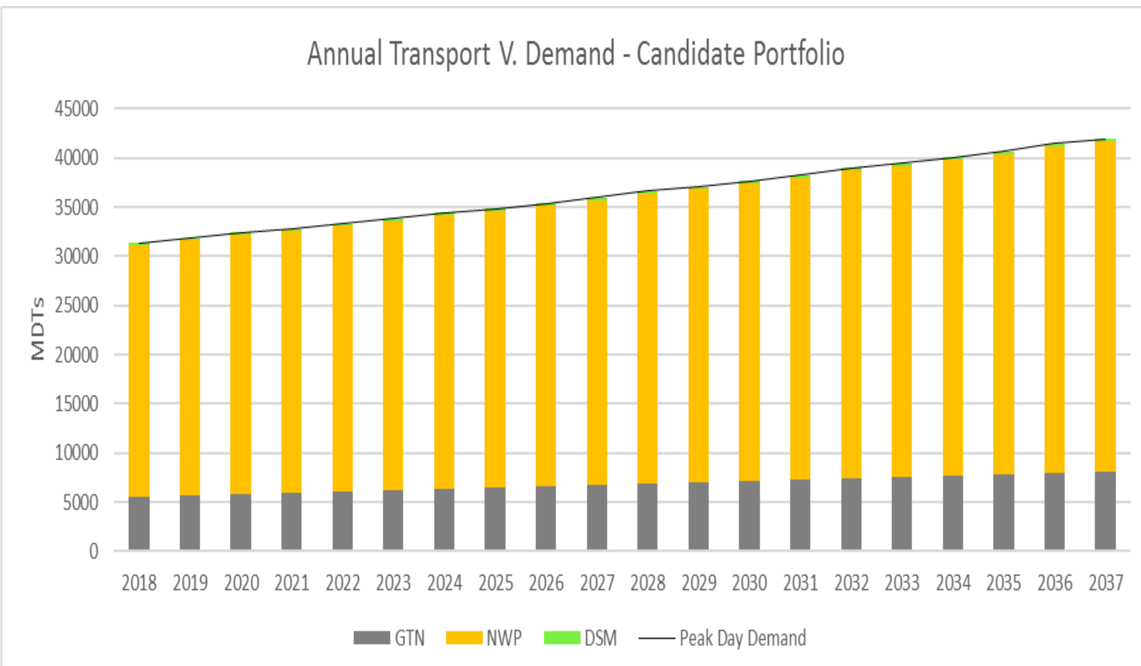
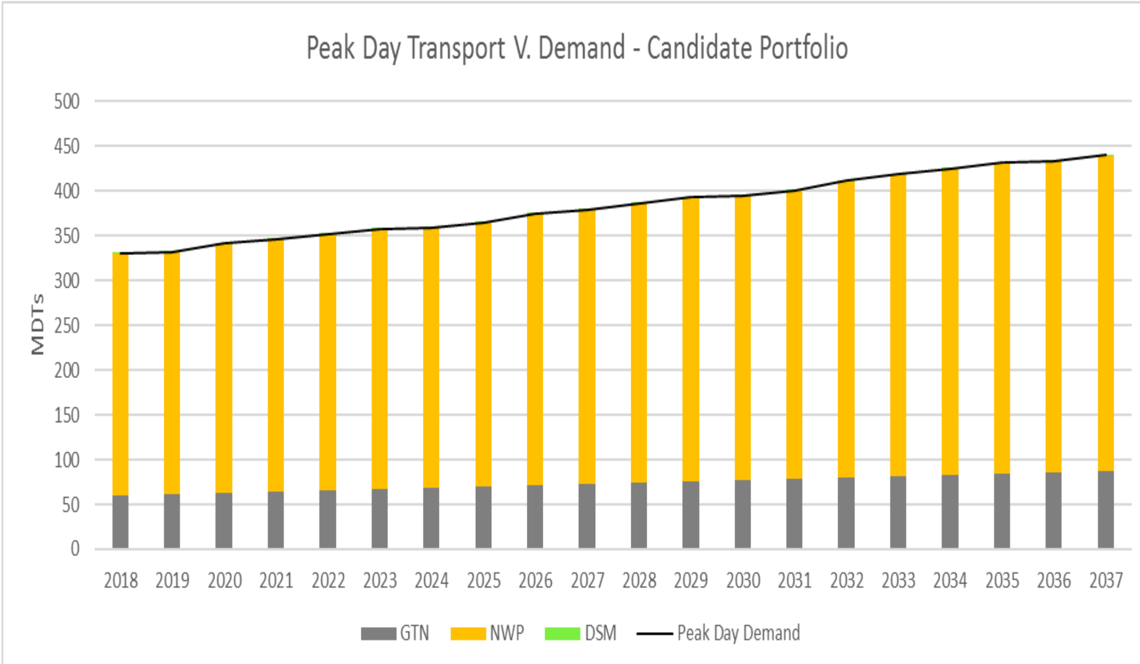


Figure 7-12: Peak Day Transport vs Demand – Candidate Portfolio



Portfolio Evaluation: Additional Scenarios

Table 7-8 summarizes the net present value of the revenue requirement (PVRR) of all additional demand scenarios reviewed. After the Candidate Portfolio was selected, the Company tested it stochastically through a number of extreme situations, which are further explained in Appendix E, Current and Alternative Supply Resources. The results of all scenarios are also shown graphically in Figures 7-13 and 7-14.

Table 7-8: Total System Cost ($000) and Average Cost/Served Therm of Additional Demand Scenarios

Scenarios and Sensitivities	Mean Total System Cost	Cost/Therm Served	VaR Total System Cost	Distance From VaR Limit
Low Growth	3,558,879	0.5201344	3,586,974	1,075,995
All-in Low Price	3,677,101	0.5075281	3,706,370	956,598
All-in Base Price	3,730,375	0.5153141	3,761,824	901,145
Limit Ply	3,735,878	0.5155768	3,767,042	895,927
No Storage - Ply	3,735,878	0.5158650	3,767,042	895,927
All-in High Price	3,768,059	0.5205797	3,799,758	863,210
Limit JP	3,771,225	0.5205295	3,802,429	860,540
10% Adder	3,774,250	0.5252791	3,814,772	848,196
Limit Both JP and Ply	3,781,513	0.5251511	3,813,037	849,932
No Storage - JP	3,786,551	0.5225589	3,817,561	845,408
No Storage - Both JP and Ply	3,806,273	0.5472874	3,843,720	819,249
10$ Per Ton Adder	3,810,576	0.5299892	3,847,100	815,868
20% Adder	3,845,766	0.5340682	3,880,357	782,612
20$ Per Ton Adder	3,901,711	0.5414488	3,933,235	729,733
High Growth	3,904,353	0.5101826	3,937,995	724,974
30% Adder	3,907,371	0.5419494	3,938,963	724,006
30$ Per Ton Adder	3,978,920	0.5513975	4,006,628	656,341

Figure 7-13: Total System Cost Comparison by Scenarios/Sensitivity

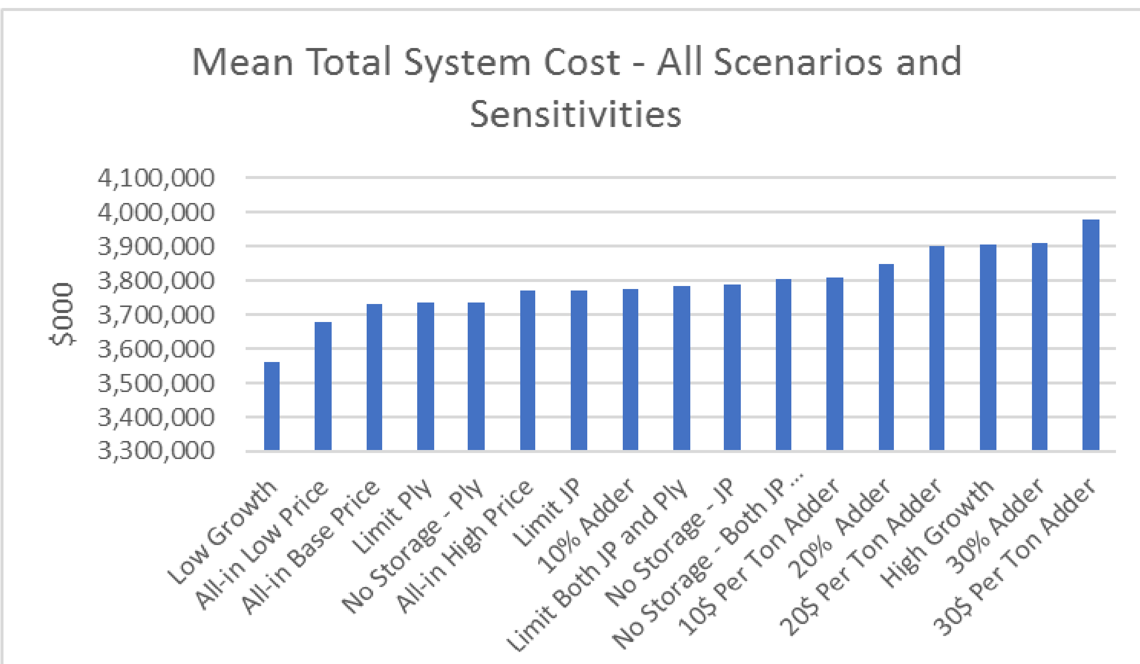
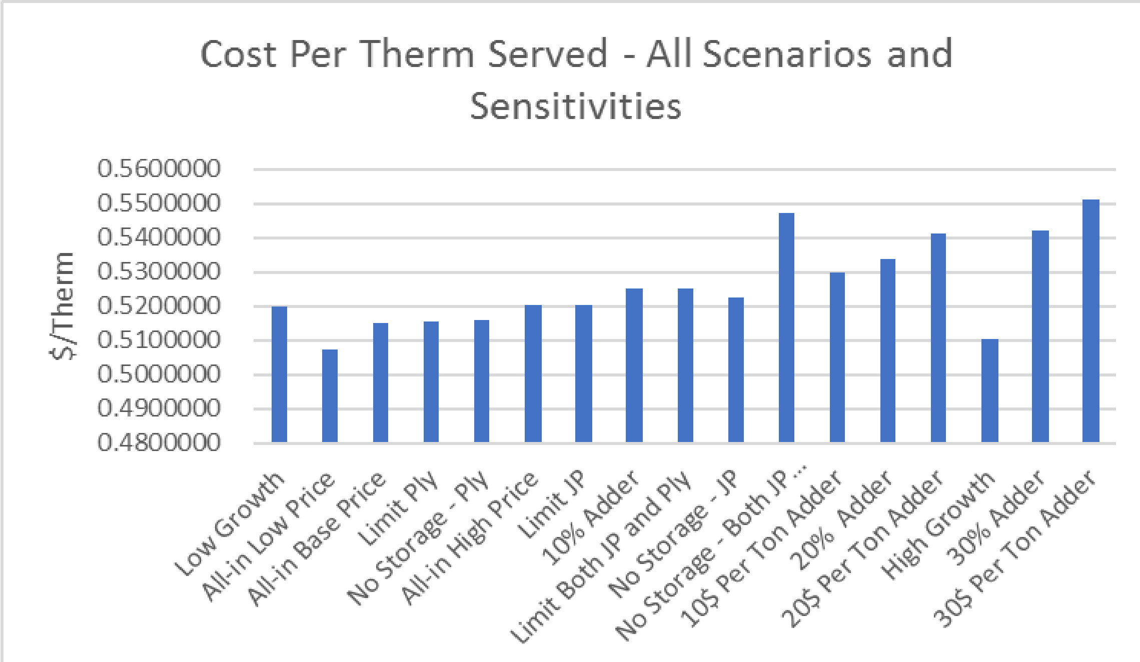


Figure 7-14: Cost per Therm Served by Scenario/Sensitivity



Stochastic Analyses - Annual Load Requirements and Weather Uncertainty

The annual load requirements will vary dramatically based on the weather assumptions. Through the use of the SENDOUT® Monte Carlo functionality, the Company has the ability to analyze the impacts of weather on its load forecast. Figure 7-15 provides the low parameter, which is based on the assumption that the low load growth forecast occurs. Figure 7-16 provides a more in-depth look at the expected, or medium, scenario results. This assumes that growth is at the expected rate, and price follows the expected price forecast. Figure 7-17 provides the high parameter occurring under the high load growth forecast. Capturing the uncertainty around load growth forecasting was accomplished through SENDOUT® Monte Carlo functionality. The Monte Carlo simulation performed 200 draws with each draw calculating the monthly load based on the weather as randomly determined by the model for each of the weather zones. The absolute maximum and absolute minimum amounts depict the minimum or maximum system demand from the 200 draws for a particular year. The absolute maximum/minimum does not represent any single result for the 20-year planning horizon.

Figure 7-15: Therms Served – Low Growth Monte Carlo Weather Scenarios – Expected Scenario

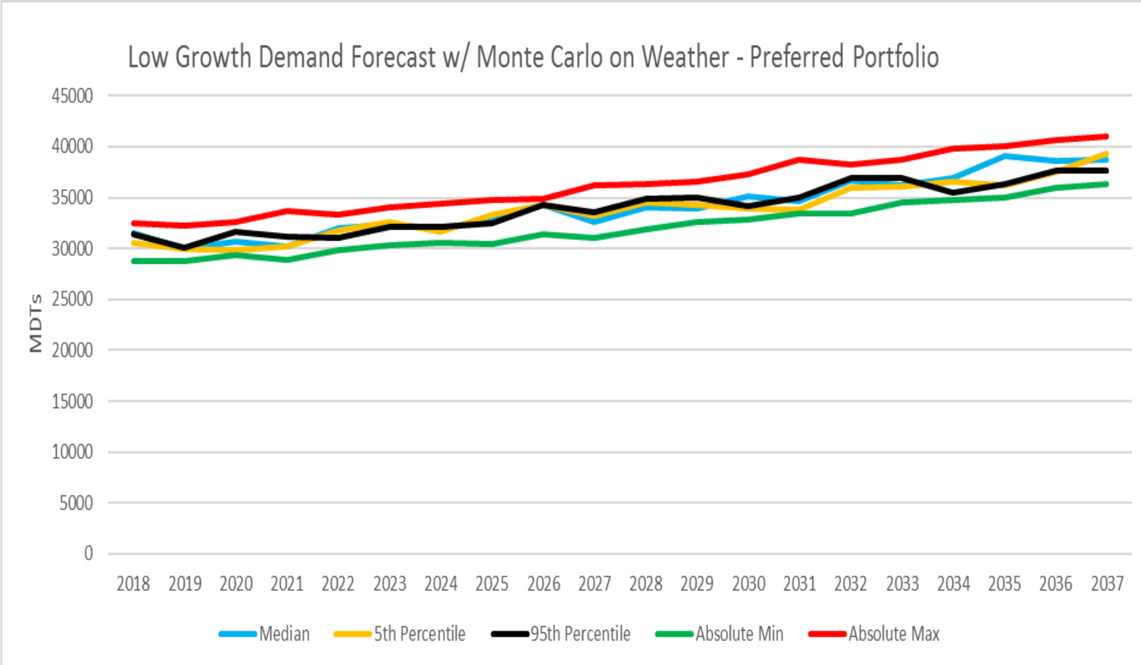


Figure 7-16: Therms Served – Average Growth Monte Carlo Weather Scenarios – Expected Scenario

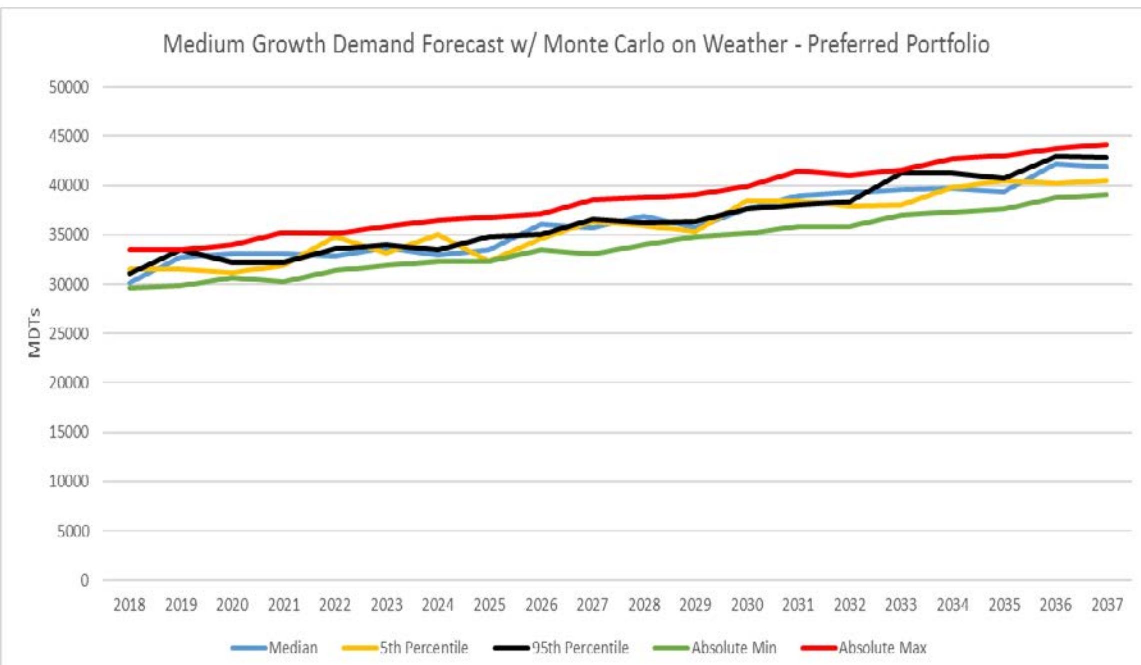
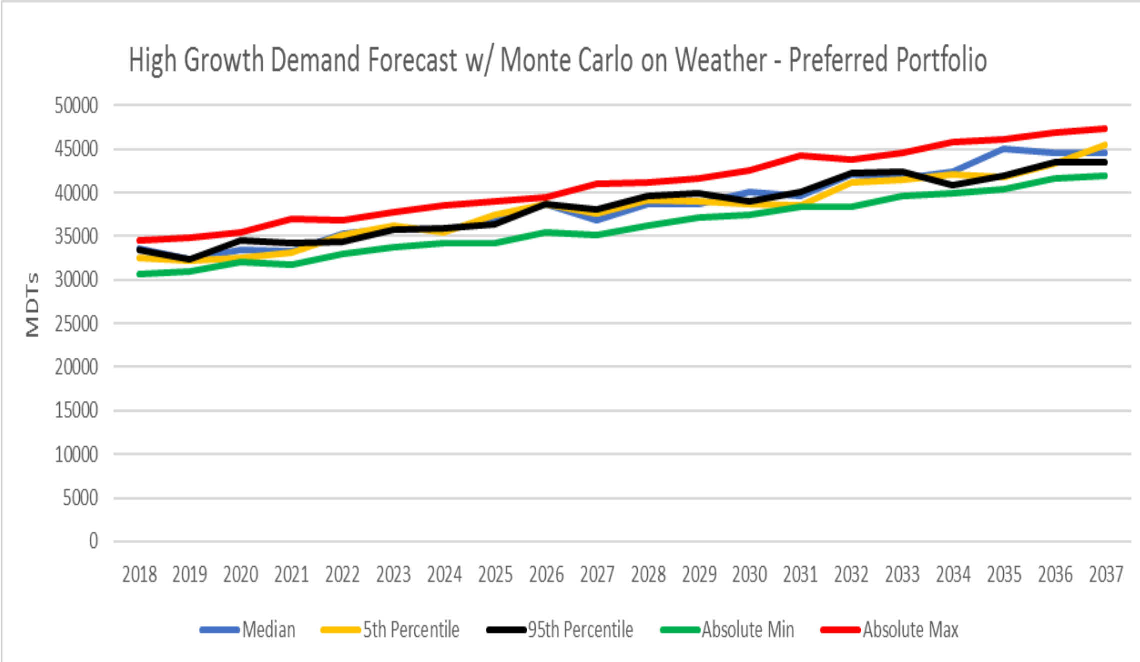


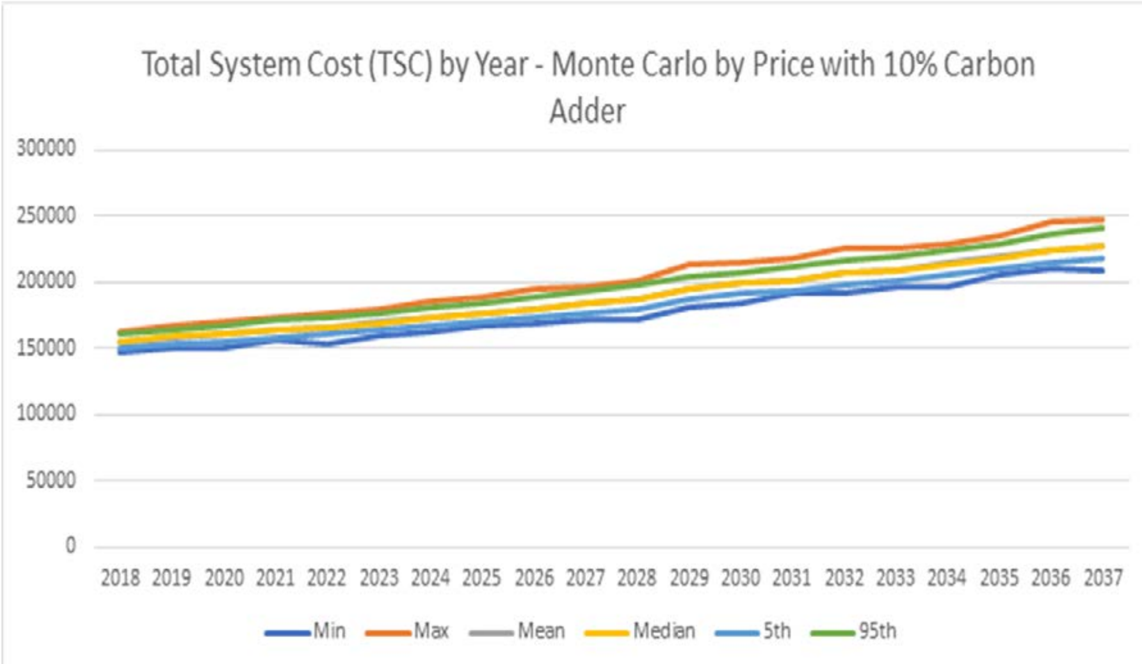
Figure 7-17: Therms Served – High Growth Monte Carlo Weather Scenarios – Expected Scenario



Stochastic Results: Price Uncertainty

The following charts show results when the Candidate Portfolio is stress tested in different scenarios. For price, these charts depict how the portfolio performs with regard to total system costs in an expected growth environment over 200 random pricing scenarios. These results are shown in Figure 7-18. With the analyses on price and weather uncertainty, the Company can gain a perspective of how Cascade's expected portfolio would perform in extreme weather and price situations.

Figure 7-18: Total System Cost ($000) – Monte Carlo by Price Preferred Portfolio



Monte Carlo Inputs

When performing a Monte Carlo simulation in SENDOUT®, the user provides the following inputs for both price and weather simulations:

- Mean Value – this tells SENDOUT® what the mean value should be over the 200 draws. This number is the same as the deterministic input for either price (in $/MMBtu) or HDDs. Cascade used the 20-year price forecast for the mean value on price. The average of the previous 30-years of weather were used for the mean value of HDDs. For example, the average of each January from 1987-2016 make up the mean value for January.

- Standard Deviation (Std Dev) – this tells SENDOUT®, based on the type of distribution selected, how far above and below the mean that the data points will fall depending on the draw and how many points should fall within a certain range. Cascade used the standard deviation of the previous 30-years of weather to determine the standard deviation for Monte Carlo simulations. For price, standard deviation increases at a linear rate to account for less certainty as the time horizon increases.

- Distribution - this tells SENDOUT® if the draws should be distributed normally or lognormally. Weather is distributed normally while price is distributed lognormally. When analyzing a certain month of weather, the data follows a normal distribution, therefore *Normal* was chosen for the distribution. The Company has observed that pricing follows a lognormal distribution.

- Max - this tells SENDOUT® what the highest result can be for either price or HDDs for a given month. The max for weather is chosen by using the highest monthly HDD value from the previous 30-years of weather data. The Company used 2 standard deviations above the mean for the max.

- Min - this tells SENDOUT® what the lowest result can be for either price or HDDs for a given month. The min for weather is chosen by using the lowest monthly HDD value from the previous 30-years of weather data. The Company used 2 standard deviations below the mean with a floor of $1.50/mmbtu for the min.

Figures 7-19 and 7-20 below show an example of these inputs for an index, as well as for a climate zone.

Figure 7-19: Sample Monte Carlo Inputs - Index

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017
*Mean Value	3.60	3.95	4.38	4.36	4.29	4.01	4.05
Std Dev	0.200	0.221	0.241	0.262	0.282	0.303	0.324
Distribution	Lognormal						
Max	4.10	4.51	4.99	5.01	4.99	4.77	4.86
Min	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Weather Effect Up Function							
Weather Effect Up Threshold DD							
Weather Effect Up Rate							
Weather Effect Down Function							
Weather Effect Down Threshold DD							
Weather Effect Down Rate							
Jump Threshold DD							
Jump Probability							
Jump Multiplier							
Max Daily							
Min Daily							

Figure 7-20: Sample Monte Carlo Inputs – Climate Zone

	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017
HDD Mean	764.6	1026.1	1031.8	804.1	639.6	453.9	254.2
HDD Std Dev	93.7	108.8	145.4	133.1	84.4	93.0	72.2
HDD Distribution							
HDD Max	932	1290	1291	1242	841	641	426
HDD Min	534	861	772	568	448	254	92
CDD Mean							
CDD Std Dev							
CDD Distribution							
CDD Max							
CDD Min							

Alternative Forecasting Methodologies and Consideration of Modeling Modification

Forecasting is the foundation of integrated resource planning, highly influencing most key items in the two-year action plan and 20-year planning horizon. Chief among these is the determination of the avoided cost of natural gas, which, in addition to gas supply issues, affects conservation programs.

Qualitative (scenario planning) and quantitative methods (regression modeling of historic data) are combined to arrive at low, medium, and high forecasts. A range of end-results are used to determine sensitivity of specific parameters (e.g., customer growth, use per customer, retail price, carbon policy, etc.). Commission Staff and stakeholders scrutinize the assumptions and inputs. A low forecast would result in fewer planned conservation programs. High forecasts may be overly influenced by uncertainties of future industry issues (e.g., carbon policy), resulting in excess costs. Commission Staffs and stakeholders, across states and fuels (i.e., natural gas and coal), request consideration of alternative forecasting methods. This, in practicality, has two meanings: One meaning is technical, focusing on improvements and additions to previous modeling.[3] The second meaning is policy-based (although included in the technical modeling), and lies in sensitivity analysis and scenario planning. For example, scenario planning incorporates adders, such as cost-per-ton of carbon emissions (i.e., CO_2).

Throughout each planning cycle, all Oregon and Washington jurisdictional utilities have been requested to improve their technical modeling and include robust sensitivity and scenario analyses to effectuate alternative forecasting methods.

For this IRP the Company is using an ARIMA forecasting methodology. Cascade currently uses SENDOUT®, a platform all Oregon and Washington LDCs use to find the optimal solve for any deficiency that is projected based on the forecast. Through ARIMA forecasting methodology and scenario planning with Monte Carlo draws, a stochastic (that is, based on random event planning) 20-year forecast is derived.[4]

As previously identified in Section 3, Demand Forecast, the Company believes that future IRPs will be enhanced by adopting additional technical modifications. Cascade plans a greater inclusion of auto ARIMA functionality and deeper statistical analysis in future forecast modeling, with a continuing focus on developing a wide and deep range of scenarios. Given the improvements in forecasting, more analysis of primary variables can be gained by greater use of ARIMA equations.

[3] For example, modifications could include modules that examine uncertainty and equations that account for the delayed effects of primary variables (e.g., economic conditions).
[4] A stochastic approach or randomly determined having a random probability distribution or pattern that may be analyzed statistically but may not be predicted precisely.

Conclusion

Cascade's preferred portfolio has the lowest cost and risk as expected when considering alternate supply resources. This is primarily due to Cascade's geographical spread across the region. The Company's existing long-term transportation contracts, coupled with robust supply basins provides a base foundation to meet load needs of Cascade's core customers. However, Cascade's unique geographical reach creates particular challenges as the system is non-contiguous, often requiring the Company to hold transportation capacity on multiple upstream pipelines to feed the single upstream pipeline that is connected to a particular citygate. The cost of building or acquiring new supply resources would likely increase cost while keeping risk at similar levels.

The High Growth and Low Growth demand analyses provide a range for evaluating demand trajectories relative to the expected scenario. Based on this analysis sufficient time is expected to be available to plan for forecasted resource needs. Even under extreme pricing sensitivities related to the cost of carbon legislation compliance, Cascade has determined that this portfolio solves for resource deficiencies at an acceptable cost. Many events could occur between now and when the first resource needs materialize, so Cascade will employ adaptive management. The Company will continue to monitor and analyze system demand through reconciling and comparing forecast to actual customer counts, and will continually update and evaluate all demand side and supply side alternatives.

SECTION 8

DISTRIBUTION SYSTEM PLANNING

Overview

Cascade's IRP includes the evaluation of safe, economical, and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to Cascade's citygates become secondary issues if distribution system growth behind the citygates becomes severely constrained. Important parts of the planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions, and estimating costs for eliminating constraints.

Key Points

- Distribution system network design fundamentals anticipate demand requirements and identify potential constraints.
- Cascade utilizes its internal GIS environment and other input data to create system models through the use of Synergi® software.
- Distribution system enhance-ments include analyses of pipe-lines, regulators, and compressor stations.
- Impacts of proposed conser-vation resources on anticipated distribution constraints are reviewed.
- Analyses are performed on every system at design day conditions to identify areas where potential outages may occur.
- Cascade has identified three major enhancement projects over the next three years.

Analyzing resource needs in the IRP is primarily focused on ensuring adequate upstream capacity to the citygates, especially during a peak event. Distribution planning focuses on determining if adequate pressure will be available during a peak hour. Despite this different perspective, distribution planning shares many of the same goals, objectives, risks, and solutions as resource planning.

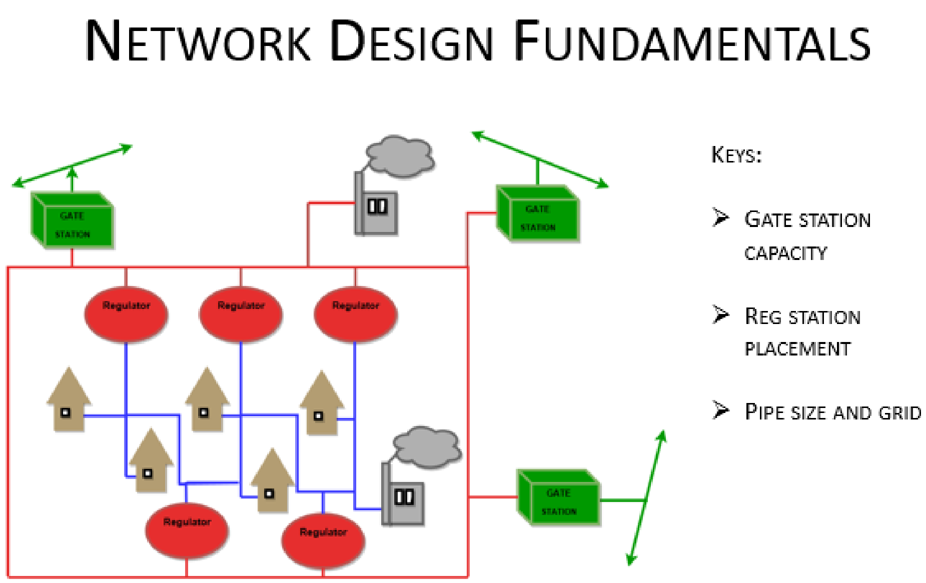
Cascade's natural gas distribution system consists of approximately 4,744 miles of distribution main pipelines in Washington, and 1,604 miles in Oregon, as well as numerous regulator stations, service distribution lines, monitoring and metering devices, and other equipment. Currently, a compressor station is located within Cascade's distribution system near Fredonia, WA. The vast majority of the distribution network pipelines and regulating stations operate and maintain system pressure solely from the pressure provided by the interstate transportation pipelines.

Network Design Fundamentals

Gas distribution networks rely on pressure differentials to move gas from one place to another. If the pressure is exactly the same on both ends of a pipe, the gas will not flow. Therefore, it is important that gas engineers design the distribution network such that the pressure in the pipe will always be high enough that a differential can be created when gas leaves the system. As gas flow increases, pressure is lost due to friction. Using the laws of fluid mechanics, engineers informed by flow modeling data determine the maximum flow of gas through a pipe of a certain diameter and length that will not cause pressure drops that are too great.

Not all natural gas flows equally throughout a network. Certain points within the network constrain flow and restrict overall network capacity. Network constraints can occur as demand requirements evolve. Anticipating these demand requirements, identifying potential constraints and forming cost-effective solutions with sufficient lead times without overbuilding infrastructure are the key challenges in network design. Figure 8-1 provides an example of a network diagram.

Figure 8-1: Network Design Fundamentals

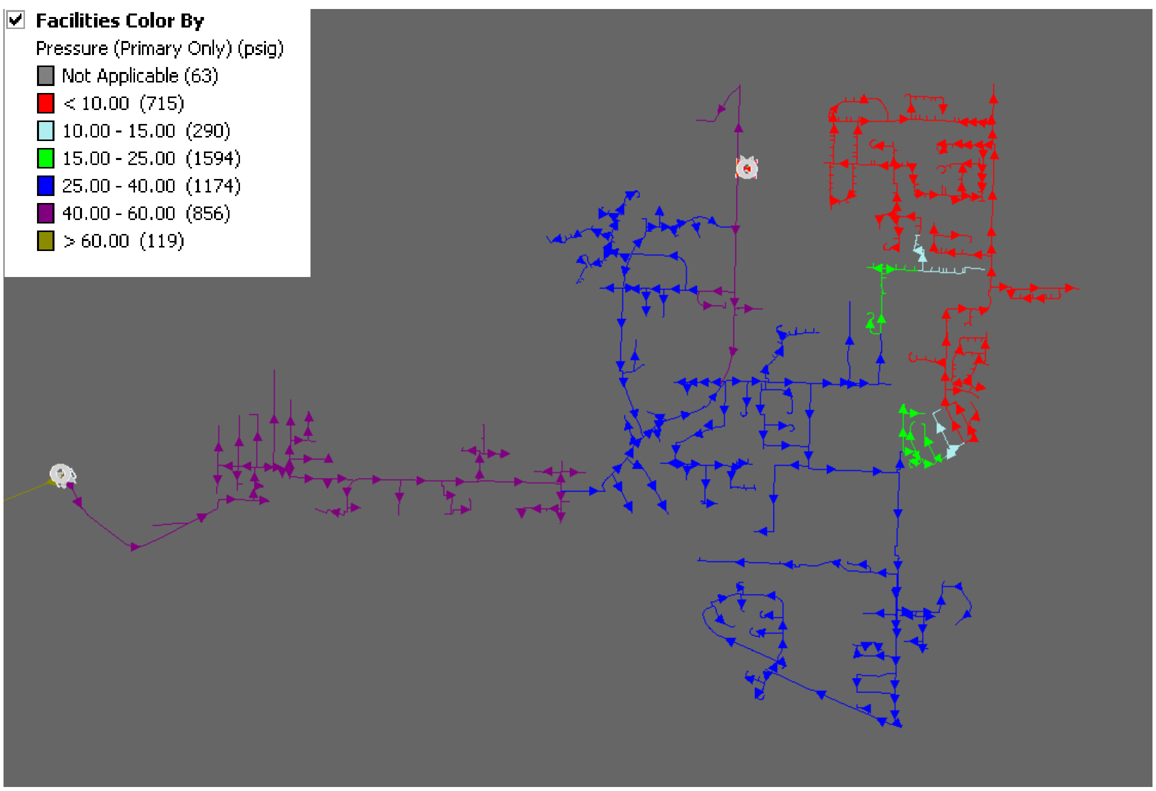


Computer Modeling

Developing and maintaining effective network design is aided by computer modeling for network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means of analyzing distribution system performance. Utilizing computer software, individual models were created for each of Cascade's different systems. These models include both high-pressure lines and distribution system networks. As gas loads are simulated to increase according to the load forecasts, the pressures within each system are checked. When the simulation shows the pressure dropping to an unacceptable level, that system and the surrounding area are determined to be a constraint area. When constraint areas are found, an engineer determines the most effective way of solving the problem.

Cascade's geographical information system (GIS) keeps an as-to-date record of pipe and facilities, complete with all system attributes such as date of install and operation pressure. Using the internal GIS environment and other input data Cascade is able to create system models through the use of Synergi® software. The software provides the means to theoretically model piping and facilities to represent current pressure and flow conditions while predicting future events and growth. Combining these models with historical weather data can provide a Design Day model that will predict a worst-case scenario. Design Day models that experience less than ideal conditions can then be identified and remedied before a real problem is encountered. Ultimately the identified projects can be funneled through the Project Process Flow (Figure 8-4 on Page 8-9) to be prioritized and slotted into the budget. Figure 8-2 is an example of a low-pressure scenario identified using Synergi®.

Figure 8-2: Low Pressure Design Example



Synergi® is used in conjunction with the GasWorks models that were built years ago and have been upgraded as needed. Cascade's philosophy is that models should be reviewed for significant changes annually and recalibrated to represent the system more accurately. Synergi® is more advanced than GasWorks and much more user friendly. Synergi® is also the modeling software of choice for many other LDCs.

Distribution System Planning

Many LDCs conduct two primary types of evaluations in their distribution system planning efforts to determine the need for resource additions, including distribution system reinforcements and expansions. Reinforcements are upgrades to existing infrastructure or new system additions, which increase system capacity, reliability, and safety. Expansions are new system additions to accommodate new demand. Collectively, these are distribution enhancements.

The engineering department works closely with engineer associates and district management to make sure the system is safe and reliable. As towns develop, the need for pipeline expansions and reinforcements increases. The expansions are historically driven by new city developments or new housing plats. Before expansions and installation can be constructed to serve these new customers, engineering analysis is performed. Using system modeling software to represent cold weather scenarios, predictions can be made about the capacity of the system. As new groups of customers seek natural gas service, the models provide feedback on how best to serve them reliably.

Another aspect of system planning involves gate capacity analysis and forecasting. Over time each gate station will take on more and more demand and it is Cascade's goal to get out in front with predictions. The IRP growth data received, along with design day modeling, allows for forecasting of necessary gate upgrades. SCADA technology utilized by Cascade allows verification of numbers with real time and historic gate flow and pressure data. The data proves reliable in verifying models and forecasting projects.

Distribution System Enhancements

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification and corresponding optimum combinations of pipe modification, and pressure modification solutions to maintain adequate pressures throughout the network. Distribution system enhancements do not reduce demand nor do they create additional supply. Enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Pipelines

Pipeline solutions consist of looping, upsizing and uprating. Pipeline looping is the most common method of increasing capacity in an existing distribution system. It involves constructing new pipe parallel to an existing pipeline that has, or may become, a constraint point. Constraint points inhibit flow capacities downstream of the constraint creating inadequate pressures during periods of high demand. When the parallel line connects to the system, this alternative path allows natural gas flow to bypass the original constraint and bolsters downstream pressures. Looping can also involve connecting previously unconnected mains. The feasibility of looping a pipeline depends upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, and steep or rocky terrain can increase the cost to a point where alternative solutions are more cost-effective.

Pipeline upsizing involves replacing existing pipe with a larger size pipe. The increased pipe capacity relative to surface area results in less friction, and therefore, a lower pressure drop. This option is usually pursued when a pipe is damaged or has integrity issues. If the existing pipe is otherwise in satisfactory condition, looping augments existing pipe, which remains in use.

Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional facilities. However, safety considerations and pipe regulations may prohibit the feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating costly repairs. A thorough review is conducted to ensure pipeline integrity before pressure is increased. Figure 8-3 provides a snapshot of some of the major components of the system.

Figure 8-3: Cascade System Pipeline Overview

PIPELINE:

- DIAMETER – ½" TO 20"
- MATERIAL – POLYETHYLENE AND STEEL
- OPERATING PRESSURE - 20 PSI TO 900 PSI
- WASHINGTON – APPROX. 4,744 MILES OF DISTRIBUTION MAIN
- OREGON – APPROX. 1,604 MILES OF DISTRIBUTION MAIN

Regulators

Regulators or regulator stations reduce pipeline pressure at various stages in the distribution system. Regulation provides a specified and constant outlet pressure before natural gas continues its downstream travel to a city's distribution system, a customer's property, or a natural gas appliance. Regulators also ensure that flow requirements are met at a desired pressure regardless of pressure fluctuations upstream of the regulator. Regulators are at citygate stations, district regulator stations, farm taps, and customer services. Utilization and strategic positioning of new stations can be very helpful in increasing system reliability and capacity. Cascade has over 700 regulator stations along its system.

Compression

Compressor stations present a capacity enhancing option for pipelines with significant natural gas flow and the ability to operate at higher pressures. For pipelines experiencing a relatively high and constant flow of natural gas, a large volume compressor installation along the pipeline boosts downstream pressure.

A second option is the installation of smaller compressors located close together or strategically placed along a pipeline. Multiple compressors accommodate a large flow range and use smaller and very reliable compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace, so that purchasing and installing these less expensive compressors over time allow a pipeline to serve growing customer demand into the future.

Compressors can be a cost-effective option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with engineering and construction time, can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Cascade's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

Reviewing the impacts of proposed conservation resources on anticipated distribution constraints is equally important. Although the Company historically provides utility-sponsored conservation programs throughout a particular jurisdiction (i.e. all of Washington or all of Oregon), there may be instances where a more targeted approach could reduce or delay the estimated reinforcement for a specific area. However, as discussed in Section 6, DSM and Environmental Policy, the acquisition of conservation resources is entirely dependent upon the individual consumer's day-to-day purchasing and behavior decisions. Although the utility attempts to influence these decisions through its conservation programs, the consumer is still the ultimate decision maker regarding the purchase of a conservation measure. Therefore, the Company does not anticipate that the peak day load reductions resulting from incremental conservation will be adequate enough to eliminate distribution system constraint areas at this time. However, over the longer term (through 2027), the opportunity for targeted conservation programs to provide a cumulative benefit that offsets potential constraint areas may be an effective strategy.

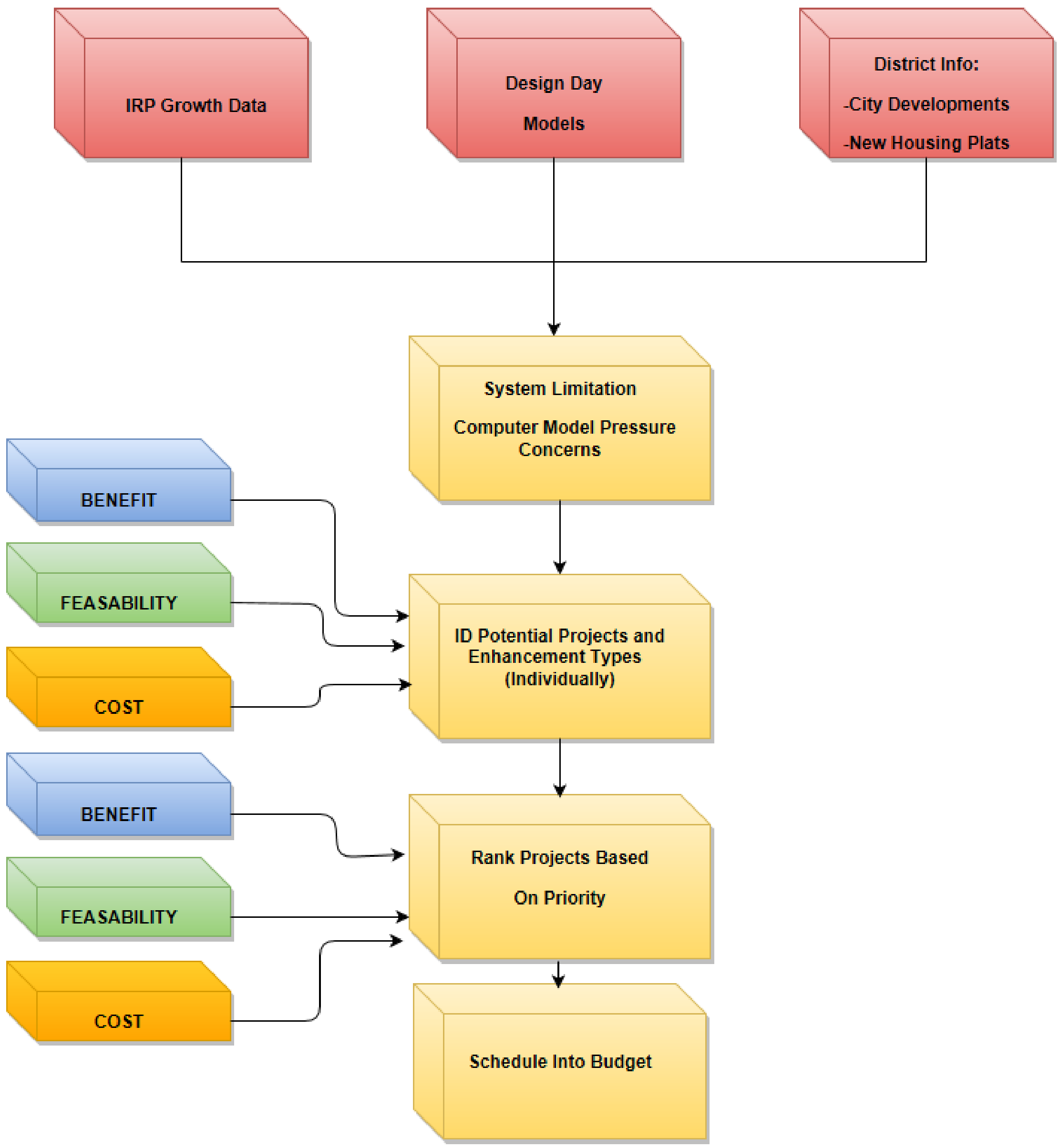
Distribution Scenario Decision-Making Process

After achieving a working load study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur. These areas of concern are then risk ranked against each other to ensure the highest risk areas are corrected first. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient part of the distribution system.
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights or traffic issues.
- Minimal to no water, railroad, major highway crossings, etc.
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, the design engineer or construction project coordinator (CPC) begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of the above project/reinforcement selection criteria. Figure 8-4 provides a schematic representation of the distribution scenario process.

Figure 8-4: Distribution Scenario Process



Planning Results

Table 8-1 summarizes the cost and timing of three major distribution system enhancements addressing growth-related system constraints, system integrity issues and the timing of expenditures. The detail on these sample projects provides preliminary estimates of timing and costs of major reinforcement solutions. The scope and needs of distribution system enhancement projects generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to differences in actual growth patterns and/or construction conditions that differ from the initial assessment.

The following discussion provides information about the three sample, near-term projects:

- Bend 6" HP Steel Reinforcement - This high pressure steel project will help the capacity in the entire Bend system. The city of Bend has seen a great deal of growth in the recent past and expects more in the future. The project will consist of installing 6,400' of 6" and 8" high pressure steel. The project cost is forecasted to be $1,930,648 and the expected completion date is 2018.

- Bend 4" IP PE Reinforcement: Archie Briggs Rd - This intermediate pressure reinforcement will tie together two separate sections of the Bend system in northwestern Bend. This area has seen a great deal of growth and design day models are forecasting pressure issues in the future. The project consists of almost 1,950' of 4" PE. The project cost is estimated to be $ 191,066 and it is expected to be completed in 2019.

- Bend 4" IP PE Reinforcement: Hayes Ave. - This intermediate pressure reinforcement will help strengthen the center of the Bend distribution system. Model forcasts with continued growth show there will be pressure concerns in this area of the system between Bend Parkway and the Deschutes River. The project will consist of 1,200' of 4" PE and will tie together two segments isolated from each other by the Bend Parkway. It is expected to cost about $204,454 and is forecasted to be completed in 2019.

Table 8-1: Distribution Planning Capital Projects

Location	2018	2019
Bend 8”/6” HP Steel Reinforcement	$ 1,930,648	
Bend 4” IP PE Reinforcement: Archie Briggs Rd		$ 191,066
Bend 4” IP PE Reinforcement: Hayes Ave		$ 204,454

Table 8-1 highlights just a few of Cascade’s near future growth projects. All engineering projects can be found in Appendix I. With the use of the computer modeling software and Cascade’s Distribution Scenario Process, the Company can identify projects for the longer term. As projects are completed they are integrated into the system to make sure the model is current. This ensures that Cascade is using the most recent versions of its system moving forward.

Conclusion

Cascade’s goal is to maintain its natural gas distribution system’s reliablity and to cost effectively deliver natural gas to every core customer. This goal relies on modeling to increase the capacity and reliability of the distribution system by identifying specific areas that may require changes. The ability to meet the goal of reliable and cost effective natural gas delivery is enhanced through localized distribution planning, which enables coordinated targeting of distribution projects responsive to customer growth pattern.

SECTION 9

STAKEHOLDER ENGAGEMENT

Overview

Input and feedback from Cascade's Technical Advisory Group (TAG) are an important resource for ensuring the IRP includes perspectives beyond the Company's and is responsive to stake-holders' concerns.

Key Points

- Five Technical Advisory Group (TAG) meetings were held - one in Portland, three in Salem, and one via WebEx.
- Multiple opportunities for public participation were available.
- TAG meeting Agendas and presentations are available at www.cngc.com.

Approach to Meetings and Workshops

The Company's standard approach is to hold a series of public meetings, typically in Salem. Cascade's IRP stakeholders are widely spread out geographically; Salem is more easily accessible for individuals to attend than Kennewick. For those unable to travel, all meetings were available by WebEx/teleconference. Cascade scheduled five TAG meetings between May and December of 2017.

Cascade recognizes the involvement in the Company's TAG represents a material time commitment. The Company appreciates the investment of time attendees provide to this process by reviewing multiple documents and making subsequent suggestions. This IRP has benefited from the focus of the engaged stakeholders.

List of Stakeholders

The Company encourages public participation in the IRP process. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest LDCs and other utilities, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Citizens' Utility Board, and the Northwest Industrial Gas Users.

Internally, the Cascade IRP stakeholders and participants are from the following departments:

- Resource Planning;
- Gas Supply/Gas Control;
- Regulatory Affairs;
- Operations/Engineering;
- Conservation, Energy Efficiency;
- Finance/Accounting;
- Information Technology; and
- Executive group.

Additionally, Cascade contracted the services of an IRP consultant, Bruce W Folsom Consulting LLC, to assist the Company with meeting the 2018 IRP schedule.

TAG Meetings

Cascade held five public TAG meetings with internal and external stakeholders. Information about each meeting date and major agenda items are provided below as well as in Appendix A.

2018 IRP TAG 1 Meeting – Thursday, May 11, 2017

- Location: Salem at the OPUC Offices, 9 am to 12 pm
- IRP Timeline
- Regional Market Outlook
- Demand Forecast Methodology
- Address 2014 IRP Concerns

2018 IRP TAG 2 Meeting – Wednesday, July 19, 2017

- Location: Salem at the OPUC Offices, 9 am to 12 pm
- Distribution System Planning
- Planned Scenarios and Sensitivities
- Alternative Resources
- Price Forecast
- Avoided Cost
- Current Supply Resources
- Transport Issues

2018 IRP TAG 3 Meeting – Thursday, September 7, 2017

- Location: Portland at Portland International Airport, 9 am to 12 pm
- Carbon Impacts
- Conservation (lead presenter: Energy Trust of Oregon)
- Preliminary Resource Integration Results
- Proposed New 2-year Plan

2018 IRP TAG 4 Meeting – Thursday, October 19, 2017

- Location: Salem at the OPUC Offices, 9 am to 12 pm
- Final Integration Results
- Finalization of Plan Components

2018 IRP TAG 5 Meeting Part One – Wednesday, December 21, 2017

- Location: WebEx Only
- Review of Staff Comments

2018 IRP TAG 5 Meeting Part Two – Wednesday, January 10, 2018

- Location: WebEx Only
- Review of Staff Comments Regarding Section 6

Opportunity for Public Participation

Cascade is fully committed to ensuring the public is invited to participate in its IRP process. Cascade has a dedicated Internet webpage where customer and parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs.[1]

[1] *See:* https://www.cngc.com/rates-services/rates-tariffs/oregon-integrated-resource-plan

SECTION 10

TWO-YEAR ACTION PLAN

2018 Action Plan

The two-year action plan demonstrates Cascade's commitment to implementing its Integrated Resource Plan and creating a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.

Key Points

Cascade's 2018 Action Plan focuses on:

- Demand Forecast
- Supply Side Resources
- Demand Side Management
- Avoided Cost
- IRP Process

Demand Forecast

The Company has purchased SAS analytics, a statistical analysis software, and uses it in conjunction with R, another analysis software, to run its ARIMA forecast models. Cascade will analyze the Auto-ARIMA functionality in R for possible inclusion in its future demand forecasts. The Company will provide an update on this analysis with Cascade's IRP update annual filing.

Supply Side Resources

The OPUC initiated docket UM 1720 as a result of long-term hedging guidelines proposed by NW Natural in their 2014 IRP.[1] Cascade has been an active participant in this docket and over the course of the next two years, the Company will implement a more robust hedging strategy that is consistent with any guidance provided in UM 1720, as well as part of the Company's compliance with the Washington Utilities and Transportation Commission (WUTC) Policy and Interpretative Statement on Local Distribution Companies' (LDCs) Natural Gas Hedging Practices in Docket UG 132019. Cascade will provide an update of the Company's hedging activities and seek stakeholder input regarding any enhanced hedging process at each UM 1286 mandated PGA quarterly meeting.

[1] OPUC has closed docket UM 1720 as a part of Order 18-019

Demand Side Management (Conservation)

DSM Action Item 1
Cascade will strive to acquire the following amount of cost-effective gas therm savings over the next two years:

	2018	2019
Oregon	609,093	631,223
Washington	876,574	921,441
Total	1,485,667	1,552,664
*stated as gross therms		

The Company will acquire cost-effective therm savings by partnering with Energy Trust in Oregon and by delivering programs under the oversight of the Company's Conservation Advisory Group in Washington. Short-term annual therm savings targets are refined annually in Oregon by the Energy Trust through the budgeting process and in Cascade's Conservation Plan, which the Company files each December 1st in Washington.

DSM Action Item 2
The Company will examine the impact changes such as revised building codes, OPUC exemptions granted for non-cost-effective measures, and changes to avoided cost calculations stemming from Docket No. UM 1893, may have on the Company's long- and short-term conservation potential. Success shall be measured by the following:

- The Company shall hold at least one meeting with the Energy Trust to discuss any changes that might affect the Company's energy efficiency therm savings targets, and, if applicable, what actions may need to be taken to comply with or adapt to the changes.
- Cascade will provide a summary of its meeting with the Energy Trust in its 2019 IRP Annual Update. In compliance with OAR 860-021-0400(9), the Company will file an update as soon as is reasonably possible if any changes result in a significant deviation from the 2018 IRP.

DSM Action Item 3
The Company will work with the Energy Trust of Oregon to discuss how various carbon tax scenarios impact which energy conservation measures are undertaken. This analysis will be included in future IRPs.

Avoided Cost

At this time, Cascade's distribution system costs are not included in the Company's avoided cost calculation. The Company will work on developing a methodology for quantifying its distribution costs for inclusion in its 2020 IRP. The Company will provide a progress report with Cascade's IRP update annual filing.

IRP Process

Cascade recognizes the importance of gathering best practices from its fellow local distribution companies (LDCs). To that end, the Company will participate in the IRP process of at least three regional utilities over the course of the next two years with the objective of incorporating aspects that may enhance Cascade's IRP.

Table 10-1 highlights specific activities of the 2018 Action Plan.

Table 10-1: Highlights of Draft 2018 Action Plan

Functional Area	Anticipated Action	Timing
Demand Forecast	Expanding forecast to test Auto-ARIMA functionality in R.	Beginning in 2018 for inclusion in 2020 IRP
Supply Side Resources	Active participation in meetings related to UM-1720 to ensure Cascade engages in best practices related to hedging.	Ongoing, for inclusion in 2020 IRP
DSM	The Company will acquire cost-effective therm savings by partnering with Energy Trust in Oregon and by delivering programs under the oversight of the Company's Conservation Advisory Group in Washington.	Ongoing, for inclusion in 2020 IRP
DSM	The Company will examine the impact changes such as revised building codes, OPUC exemptions granted for non-cost-effective measures, and changes to avoided cost calculations stemming from Docket No. UM 1893, may have on the Company's long- and short-term conservation potential.	Summary will be provided in the 2019 Annual IRP Update
DSM	Cascade will examine how carbon tax scenarios impact which energy conservation measures are undertaken with ETO.	Ongoing, for inclusion in 2020 IRP
Avoided Cost	Investigate incorporating distribution system costs into the avoided cost calculation.	Beginning in 2018 for inclusion in 2020 IRP
IRP Process	Active participation in regional LDC IRP processes.	Beginning in 2017 for inclusion in 2020 IRP

SECTION 11

GLOSSARY AND MAPS

GLOSSARY OF TERMS AND ACRONYMS

ABB™
Add-in product to the SENDOUT® model that facilitates the ability to model gas price and load uncertainty (driven by weather) into the future. ABB™ brings a Monte Carlo approach in to the linear programming approach utilized in SENDOUT®.

ACEEE
American Council for an Energy-Efficient Economy.

ACHIEVABLE POTENTIAL
Represents a realistic assessment of expected energy savings, recognizing and accounting for economic and other constraints that preclude full installation of every identified conservation measure.

AECO INDEX
Alberta Canada natural gas trading price.

AFUE
Annual Fuel Utilization Efficiency. Thermal efficiency measure of combustion equipment like furnaces, boilers, and water heaters.

AMA
Asset Management Agreement. An arrangement that an LDC may enter into with a marketing company to assist with transportation and storage assistance.

ANNUAL MEASURES
Conservation measures that achieve generally uniform year-round energy savings independent of weather temperature changes. Annual measures are also often called base load measures.

ARIMA MODELING
Autoregressive Integrated Moving Average. A time series analysis technique employed by Cascade in its demand and customer forecast.

ARRA
The American Recovery and Reinvestment Act of 2009.

AVOIDED COST
Marginal cost of serving the next unit of demand, which is saved through conservation efforts.

BACKHAUL SERVICE
A transaction where gas is transported the opposite direction of normal flow on a unidirectional pipeline.

BASE LOAD
As applied to natural gas, a given demand for natural gas that remains fairly constant over a period of time, usually not temperature sensitive.

BASE LOAD MEASURES
Conservation measures that achieve generally uniform year-round energy savings independent of weather temperature changes. Base load measures are also often called annual measures.

BNG
Bio Natural Gas. Typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen.

BRITISH THERMAL UNIT (BTU)
The amount of heat required to raise the temperature of one pound of pure water one-degree Fahrenheit under stated conditions of pressure and temperature; a therm of natural gas has an energy value of 100,000 BTUs and is approximately equivalent to 100 cubic feet of natural gas.

CC&B
Customer Care and Billing. Internal billing data system for Cascade Natural Gas.

CD
Contract Demand.

CITYGATE (ALSO KNOWN AS GATE STATION OR PIPELINE DELIVERY POINT)
The point at which natural gas deliveries transfer from the interstate pipelines to Cascade's distribution system.

CAR
Clean Air Rule. Greenhouse gas emissions standards codified in WAC 173-442.

CNG
Compressed Natural Gas.

CNGC
Cascade Natural Gas Corporation.

COMPRESSION
Increasing the pressure of natural gas in a pipeline by means of a mechanically driven compressor station to increase flow capacity.

COMPRESSOR
Equipment which pressurizes gas to keep it moving through the pipelines.

CONSERVATION MEASURES
Installations of appliances, products, or facility upgrades that result in energy savings.

CONTRACT DEMAND
The maximum daily, monthly, seasonal, or annual quantities of natural gas, which the supplier agrees to furnish or the pipeline agrees to transport, and for which the buyer or shipper agrees to pay a demand charge.

COP
Coefficient of Performance.

CORE CUSTOMERS
Residential, firm industrial and commercial gas customers who require utility gas service.

COST-EFFECTIVENESS
The determination of whether the present value of the therm savings for any given conservation measure is greater than the cost to achieve the savings.

CPI
Consumer Price Index, as calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics.

DAY GAS
Gas that can be purchased as needed to cover demand in excess of the base load.

DEKATHERM
Unit of measurement for natural gas; a dekatherm is 10 therms, which is 1000 cubic feet (volume) or 1,000,000 BTUs (energy).

DEMAND SIDE MANAGEMENT (DSM)
The activity pursued by an energy utility to influence its customers to reduce their energy consumption or change their patterns of energy use away from peak consumption periods.

DEMAND SIDE RESOURCES
Energy resources obtained through assisting customers to reduce their demand or use of natural gas. Also represents the aggregate energy savings attained from installation of conservation measures.

DSM
Demand Side Management.

DTH
Unit of measurement for natural gas; a dekatherm is ten therms, 1,000 cubic feet (volume) or 1,000,000 BTUs (energy).

EBB
Electronic Bulletin Board.

EIA
Energy Information Administration.

ENTITLEMENTS
Flow management tool used by upstream pipelines, in conjunction with OFOs.

EXPECTED SCENARIO
Least cost mix of existing and incremental resources to solve projected unserved demand under average weather with peak event, average price, and expected growth.

EXTERNALITIES
Costs and benefits that are not reflected in the price paid for goods or services.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)
The government agency charged with the regulation and oversight of interstate natural gas pipelines, wholesale electric rates and hydroelectric licensing; the FERC regulates the interstate pipelines with which Cascade does business and determines rates charged in interstate transactions.

FIRM SERVICE OR FIRM TRANSPORTATION
Service offered to customers under schedules or contracts that anticipate no interruptions; the highest quality of service offered to customers.

FOM
First of the Month price. Supply contracts entered into on a short-term basis to cover expected demand for that month.

FORCE MAJEURE
An unexpected event or occurrence not within the control of the parties to a contract, which alters the application of the terms of a contract; sometimes referred to as "an act of God;" examples include severe weather, war, strikes, pipeline failure, and other similar events.

FUEL-IN-KIND (FUEL LOSS)
A statutory percent of gas based on the tariff from the pipeline that is lost and unaccounted for from the point where the gas was purchased to the citygate.

FUGITIVE METHANE EMISSIONS
Natural Gas that escapes the system during drilling, extraction, and/or transportation and distribution of gas.

GAS TRANSMISSION NORTHWEST (GTN)
A subsidiary of TransCanada Pipeline which owns and operates a natural gas pipeline that runs from the Canada/U.S. border to the Oregon/California border. One of the six natural gas pipelines Cascade transacts with directly.

GHG
Greenhouse Gas.

GMS
Gas Management System.

GSOC
Gas Supply Oversight Committee.

HEATING DEGREE DAY (HDD)
A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below 60 degrees Fahrenheit; a daily average temperature represents the sum of the high and low readings divided by two.

HENRY HUB
The physical location found in Louisiana that is widely recognized as the most important pricing point in the United States. It is also the trading hub for the New York Mercantile Exchange (NYMEX).

INJECTION
The process of putting natural gas into a storage facility or biomethane into the distribution system.

INTERRUPTIBLE SERVICE
A service of lower priority than firm service, offered to customers under schedules or contracts that anticipate and permit interruptions on short notice; interruption occurs when the demand of all firm customers exceeds the capability of the system to continue deliveries to all firm customers.

INTERSTATE PIPELINE
A federally regulated company that transports and/or sells natural gas across state lines.

IOU
Investor owned utility.

IRP
Integrated Resource Plan; the document that explains Cascade's plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

JACKSON PRAIRIE
An underground storage project jointly owned by Avista Corp., Puget Sound Energy, and NWP. The project is a naturally occurring aquifer near Chehalis, Washington, which is located some 1,800 feet beneath the surface and capped with a very thick layer of dense shale.

KORP
Kingsvale-Oliver Reinforcement Project.

LDC
Local Distribution Company. LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area.

LIQUEFIED NATURAL GAS (LNG)
Natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. It is liquefied to reduce its volume and thereby facilitate bulk storage and transport.

LINEAR PROGRAMMING
A mathematical method of solving problems by means of linear functions where the multiple variables involved are subject to constraints; this method is utilized in the SENDOUT® Gas Model.

LNG
Liquefied natural gas.

LOAD FACTOR
The average load of a customer, a group of customers, or an entire system, divided by the maximum load factor that can be calculated over any time period.

LOAD FORECAST
A forecast, an estimate, or a prediction of how much gas will be needed for residences, companies, and other institutions.

LOAD MANAGEMENT
The reduction of peak demand during specific, limited time periods by temporarily curtailing usage or shifting usage to other time periods. Load management reduces system peak demand very well, but can have little or no effect on total energy use. Its effects are temporary and of short duration.

LOAD PROFILE
The pattern of a customer's gas usage, hour to hour, day to day, or month to month.

LOOPING
The construction of a second pipeline parallel to an existing pipeline over the whole or any part of its length, thus increasing the capacity of that section of the system.

LRC
Lowest Reasonable Cost. LRC Methodology is used when evaluating alternatives to determine the optimal solution to a given problem.

MCF
A unit of volume equal to a 1,000 cubic feet.

MDDO
Maximum Daily Delivery Obligation.

MDQ
Maximum Daily Quantity.

MONTE CARLO ANALYSIS
A type of stochastic mathematical simulation which randomly and repeatedly samples input distributions (e.g. reservoir properties) to generate a results distribution.

MOU
Memorandum of Understanding.

NAESB
North American Energy Standards Board.

NAÏVE FORECAST
A methodology used for predicting future demand when the results from a regression analysis do not show enough of a correlation between actual demand and the forecast model. This forecast is performed by using the previous year's demand multiplied by a growth factor.

NATIONAL ENERGY BOARD (NEB)
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC).

NATURAL GAS
A naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in porous geologic formations beneath the earth's surface, often in association with petroleum; the principal constituent is methane, and it is lighter than air.

NEEDLE PEAKING RESOURCE
Utilized during severe or “arctic” cold weather.

NEPA
National Environmental Policy Act.

NEW YORK MERCANTILE EXCHANGE (NYMEX)
An organization that facilitates the trading of several commodities including natural gas.

NGV
Natural Gas Vehicles.

NOMINATION
The scheduling of daily natural gas requirements.

NON-COINCIDENT PEAK
The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than one year.

NON-CORE CUSTOMER
Large customers who contract with a third party for supply and upstream pipeline capacity. Cascade provides distribution services. Typical customers include large commercial, industrial, cogeneration, wholesale, and electric generation customers.

NORTHWEST PIPELINE CORPORATION (NWP)
A principal interstate pipeline serving the Pacific Northwest and one of six natural gas pipelines Cascade transacts with directly. NWP is a subsidiary of The Williams Companies and is headquartered in Salt Lake City, Utah.

NORTHWEST POWER AND CONSERVATION COUNCIL (NWPCC)
NWPCC consists of two members from each of the four Northwest states- Oregon, Washington, Idaho and Montana- who develop a plan for meeting the region’s electric demand.

NOVA GAS TRANSMISSION (NOVA)
See TransCanada Alberta System.

NWBOP
Northwest Builder Option Packages.

NWGA
Northwest Gas Association.

NWP
Williams-Northwest Pipeline.

NYMEX
New York Mercantile Exchange.

NYMEX HH
New York Mercantile Exchange Henry Hub.

OFO
Operation Flow Order is an order issued by an upstream pipeline to alleviate conditions, among other things, that threaten the safe operations or integrity of the pipeline, or the maintenance of operations required to provide efficient and reliable firm service. The pipeline's ability to deliver anticipated quantities, and maximize efficiency and capacity utilization is often dependent upon marinating project flow patterns (e.g. receipts, deliveries and balances). Violations or failure to comply with an OFO can result in the pipeline assessing penalties to offending shippers.

OFF-SYSTEM
Any point not on or directly interconnected with a transportation, storage, and/or distribution system operated by a natural gas company within a state.

OPAL (OPAL HUB)
Natural Gas trading hub in Lincoln County, WY.

OPUC
Oregon Public Utility Commission. The OPUC's official name is Public Utility Commission of Oregon.

PCGP
Pacific Connector Gas Pipeline Project.

PEAK DAY
The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.

PEAK DAY GAS
Gas that is purchased in a peak day situation to serve demand that cannot be satisfied by base or day gas.

PREFERRED PORTFOLIO
Cascade's term of art for the optimal mix of resources to solve for forecasted shortfalls in the 20-year planning horizon.

PRICE ELASTICITY
Economic concept which recognizes that customer consumption changes as prices rise or fall.

PSI
Pounds per Square Inch. This is the standard unit of measure when determining how much pressure is being applied when gas is flowing through a pipe.

PTCS
Performance Tested Comfort Systems.

PVRR
Present Value of Revenue Requirement.

REAL
Discounting method that excludes inflation.

RECOURSE RATE
Cost-of-service based rate for natural gas pipeline service that is on file in a pipeline's tariff and is available to customers who do not negotiate a rate with the pipeline company. Also see negotiated rate. (Source: FERC https://www.ferc.gov/resources/glossary.asp#R)

REFERENCE CASE
Average annual demand from the forecast results without peak day.

REGASIFICATION RESOURCE
Process by which LNG is heated, converting it to a gaseous state. Designed for vaporizing LNG where and when it will be used.

REGULATOR STATION
A point on a distribution system responsible for controlling the flow of gas from higher to lower pressures.

RENEWABLE FUEL
A power source that is continuously or cyclically renewed by nature, i.e. solar,

wind, hydroelectric, geothermal, biomass, or similar sources of energy.

ROCKIES INDEX
Natural gas trading price near the Rocky Mountains.

SATELLITE LNG FACILITIES
A facility for storing and vaporizing LNG to meet relatively modest demands at remote locations or to meet short-term peak demands. LNG is usually trucked to such facilities.

SEASONAL PEAKING SERVICE
The delivery of gas, firm or interruptible, sold only during certain times of the year, generally when system demands are not high.

SENDOUT®
Natural gas planning system from ABB™; a linear programming model used to solve gas supply and transportation optimization questions.

SERVICE TERRITORY
Territory in which a utility system is required or has the right to provide natural gas service to ultimate customers.

SPOT MARKET GAS
Natural gas purchased under short-term agreements as available on the open market; prices are set by market pressure of supply and demand.

STANDBY
Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility to replace normally scheduled power that becomes unavailable.

STORAGE
The utilization of facilities for storing natural gas which has been transferred from its original location for the purposes of serving peak loads, load balancing, and the optimization of basis differentials. The facilities are usually natural geological reservoirs such as depleted oil or natural gas fields or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be man-made or natural caverns. LNG storage facilities generally utilize above ground insulated tanks.

SUMAS INDEX
Natural Gas trading price near the city of Sumas, which is on the Washington/Canadian border approximately 25 miles from the Pacific Ocean.

SWAP

A financial instrument where parties agree to exchange an index price for a fixed price over a defined period.

SYNERGI®
Engineering software used to model piping and facilities to represent current pressure and flow conditions, while also predicting future events and growth.

TARIFF
A published volume of regulated rate schedules plus general terms and conditions under which a product or service will be supplied.

TEA-POT
Microsoft Excel-based modeling tool developed by Nexant Inc. to determine the Technical/Economic/Achievable Potential savings of various proposed DSM programs.

TECHNICAL ADVISORY GROUP (TAG)
Industry, customer, and regulatory representatives that advise Cascade during the IRP planning process.

TECHNICAL POTENTIAL
An estimate of all energy savings that could theoretically be accomplished if every customer that could potentially install a conservation measure did so without consideration of market barriers such as cost and customer awareness.

THERM
A unit of heating value used with natural gas that is equivalent to 100,000 British thermal units (BTU); also, approximately equivalent to 100 cubic feet of natural gas.

THROUGHPUT
The total of all natural gas volume moved through a pipeline system, including sales, company use, storage, transportation, and exchange.

TRANSCANADA ALBERTA SYSTEM
Previously known as NOVA Gas Transmission; a natural gas gathering and transmission corporation in Alberta that delivers natural gas into the TransCanada BC System pipeline at the Alberta/British Columbia border; one of six natural gas pipelines Cascade transacts with directly.

TRANSCANADA BC SYSTEM
Previously known as Alberta Natural Gas; a natural gas transmission corporation of British Columbia that delivers natural gas between the TransCanada-Alberta System and GTN pipelines that runs from the Alberta/British Columbia border to the United States border; one of six natural

gas pipelines Cascade transacts with directly.

TRANSPORTATION GAS
Natural gas purchased either directly from the producer or through a broker, and used for either system supply or for specific end-use customers, depending on the transportation arrangements; NWP and GTN transportation may be firm or interruptible.

TRC
Total Resource Cost.

TSA
Transportation Service Agreement.

TURN-BACK CAPACITY
When natural gas shippers, upon expiration of their contract(s) for pipeline capacity do not renew capacity rights, in whole or in part, with the original pipeline.

UPSTREAM PIPELINE CAPACITY
The pipeline delivering natural gas to another pipeline at an interconnection point where the second pipeline is closer to the consumer.

W&P
Woods & Poole. An independent firm that specializes in long-term county economic and demographic projections.

WINTER GAS SUPPLIES
Gas supply purchased for all (base gas) or part (day gas) of the heating season.

WITHDRAWAL
The process of removing natural gas from a storage facility, making it available for delivery into the connected pipelines; vaporization is necessary to make withdrawals from an LNG plant.

WUTC
Washington Utilities and Transportation Commission.

VaR
Value at Risk. A metric used to quantify uncertainty into a tangible number.

ZONE
A geographical area. A geological zone means an interval of strata of the geologic column that has distinguishing characteristics from surrounding strata.

ZONE - IRP

For modeling purposes, Cascade's distribution system is divided into several zones. These zones are generally organized by the location of compressor stations on upstream pipelines or by specific weather areas. Where appropriate, the Zone-IRP is separated by state. Please see the chart on the next page that references the citygate/location to the appropriate IRP zone.

DESCRIPTION	METER	ZONEID	PIPELINE
7TH DAY ADVENTIST FARM TAP	ADVENSCH	ZONE 10	NWP
A & M RENDERING	AMRENDER	ZONE 30-W	NWP
A&W FEED LOT FARM TAP	AWFEED	ZONE 20	NWP
ABERDEEN/HOQUIAM/MCCLEARY	ABRNDHOQ	ZONE 30-S	NWP
ACME	ACME	ZONE 30-W	NWP
ALCOA, WENATCHEE	ALCOA	ZONE 11	NWP
ARLINGTON	ARLINGTN	ZONE 30-W	NWP
ATHENA/WESTON	ATHENA	ZONE ME-OR	NWP
BAKER	BAKER	ZONE 24	NWP
BELLINGHAM II	BLLINGII	ZONE 30-W	NWP
BELLINGHAM/FERNDALE	BLHAM	ZONE 30-W	NWP
BEND TAP	BEND	ZONE GTN	GTN
BREMERTON (SHELTON)	BREMERTON	ZONE 30-S	NWP
BRULOTTE HOP RANCH	BRULOTTE	ZONE 10	NWP
BURBANK HEIGHTS	BURBANKH	ZONE 20	NWP
CASTLE ROCK	CASTLERK	ZONE 26	NWP
CHEMCIAL LIME	CHEMLIME	ZONE 24	NWP
CHEMULT	CHEM	ZONE GTN	GTN
DEHANNS DAIRY FARM TAP	DEHANDRY	ZONE 10	NWP
DEMING	DEMING	ZONE 30-W	NWP
EAST STANWOOD	EAST STANWOOD	ZONE 30-W	NWP
FINLEY	FINLEY	ZONE 20	NWP
GILCHRIST TAP	GILC	ZONE GTN	GTN
GRANDVIEW	GRDVEW	ZONE 10	NWP
GREEN CIRCLE FARM TAP	GRENCIRL	ZONE 26	NWP
HERMISTON	HERMSTON	ZONE ME-OR	NWP
HUNTINGTON	HTINGTON	ZONE 24	NWP
KALAMA FARM TAP	KALAMA	ZONE 26	NWP
KALAMA NO. 2	KALAMA2	ZONE 26	NWP
KAWECKI, WENATCHEE	KAWECKI	ZONE 11	NWP
KENNEWICK	KENEWICK	ZONE 20	NWP
KOMOS FARMS TAP	KOMO	ZONE GTN	GTN
LA PINE TAP	LAPI	ZONE GTN	GTN

LAMBERT'S HORTICULTURE	LAMBERTS	ZONE 10	NWP
LAWRENCE	LAWRENCE	ZONE 30-W	NWP
LDS CHURCH FARM TAP	LDSCHURC	ZONE 30-W	NWP
LONGVIEW-KELSO	LONGVIEW	ZONE 26	NWP
LYNDEN	LYNDEN	ZONE 30-W	NWP
MADRAS TAP	MADR	ZONE GTN	GTN
MENAN STARCH	MEMANSTR	ZONE 20	NWP
MILTON FREEWATER	MILFREE	ZONE ME-OR	NWP
MISSION TAP	MISSION	ZONE ME-OR	NWP
MOSES LAKE	MOS LAKE	ZONE 20	NWP
MOUNT VERNON	MTVERNON	ZONE 30-W	NWP
MOXEE CITY	MOXEE	ZONE 11	NWP
NORTH BEND	NBEND	ZONE GTN	GTN
NORTH PASCO METER STATION	NPASCO	ZONE 20	NWP
NYSSA-ONTARIO	NYSSA	ZONE 24	NWP
OAK HARBOR/STANWOOD	OAKHAR	ZONE 30-W	NWP
OTHELLO	OTHELLO	ZONE 20	NWP
PASCO	PASCO	ZONE 20	NWP
PATERSON	PATERSON	ZONE 26	NWP
PENDLETON	PENDLETN	ZONE ME-OR	NWP
PLYMOUTH	PLYMTH	ZONE 20	NWP
PRINEVILLE TAP	PRVL	ZONE GTN	GTN
PRONGHORN TAP	PRONGHORN	ZONE GTN	GTN
PROSSER	PROSSER	ZONE 10	NWP
QUINCY	QUINCY	ZONE 11	NWP
REDMOND TAP	REDM	ZONE GTN	GTN
RICHLAND	RICHLAND	ZONE 20	NWP
SANDVIK, KENNEWICK	SANDVIK	ZONE 20	NWP
SEDRO/WOOLLEY ET AL.	SEDRO	ZONE 30-W	NWP
SELAH	SELAH	ZONE 11	NWP
SOUTHRIDGE	STHRDG	ZONE 20	NWP
SOUTH BEND	S BEND	ZONE GTN	GTN
SOUTH HERMISTON TAP	SHRM	ZONE GTN	GTN

SOUTH LONGVIEW FIBRE	SOLONG	ZONE 26	NWP
STANFIELD CITY TAP	STTAP	ZONE GTN	GTN
STEARNS TAP	STEA	ZONE GTN	GTN
SUMAS, CITY OF	SUMASC	ZONE 30-W	NWP
SUNNYSIDE	SUNSIDE	ZONE 10	NWP
TOPPENISH ET AL. (ZILLAH)	TOPENISH	ZONE 10	NWP
U & I SUGAR, MOSES LAKE	UI SUGAR	ZONE 20	NWP
UMATILLA	UMATILLA	ZONE ME-WA	NWP
WALLA WALLA	WALLA	ZONE ME-WA	NWP
WALULA	WALULA	ZONE ME-WA	GTN
WENATCHEE	WENATCHE	ZONE 11	NWP
WOODLAND WA	WOODLAND	ZONE 26	NWP
YAKIMA CHIEF FARMS	YAKCHFRM	ZONE 11	NWP
YAKIMA FIRING CENTER	YAKFIRCR	ZONE 11	NWP
YAKIMA/UNION GAP	YAKIMA	ZONE 11	NWP

Maps of System Infrastructure

Figure 11-1: Map – AECO Hub Storage

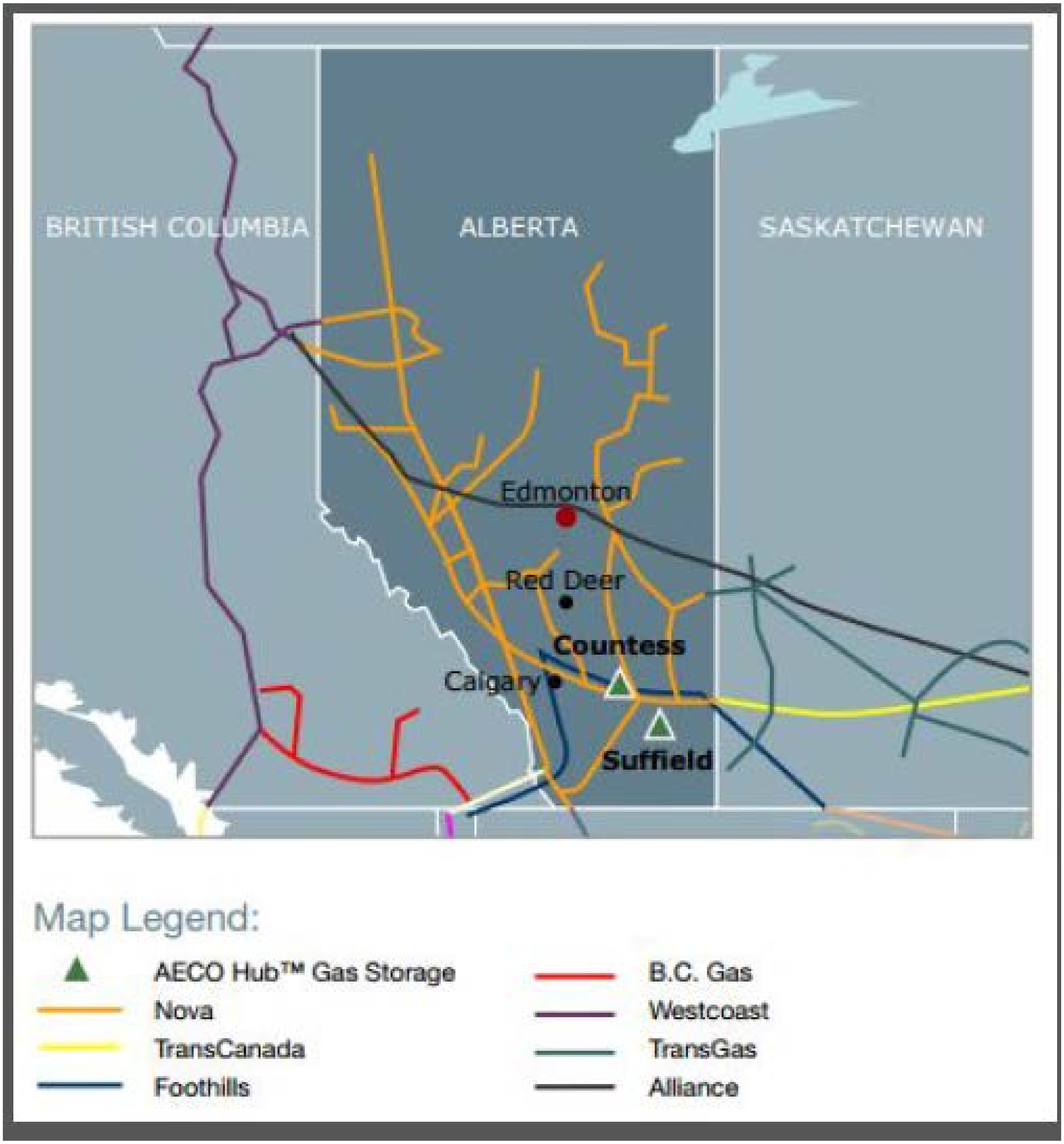


Figure 11-2: Map – California Storage Map

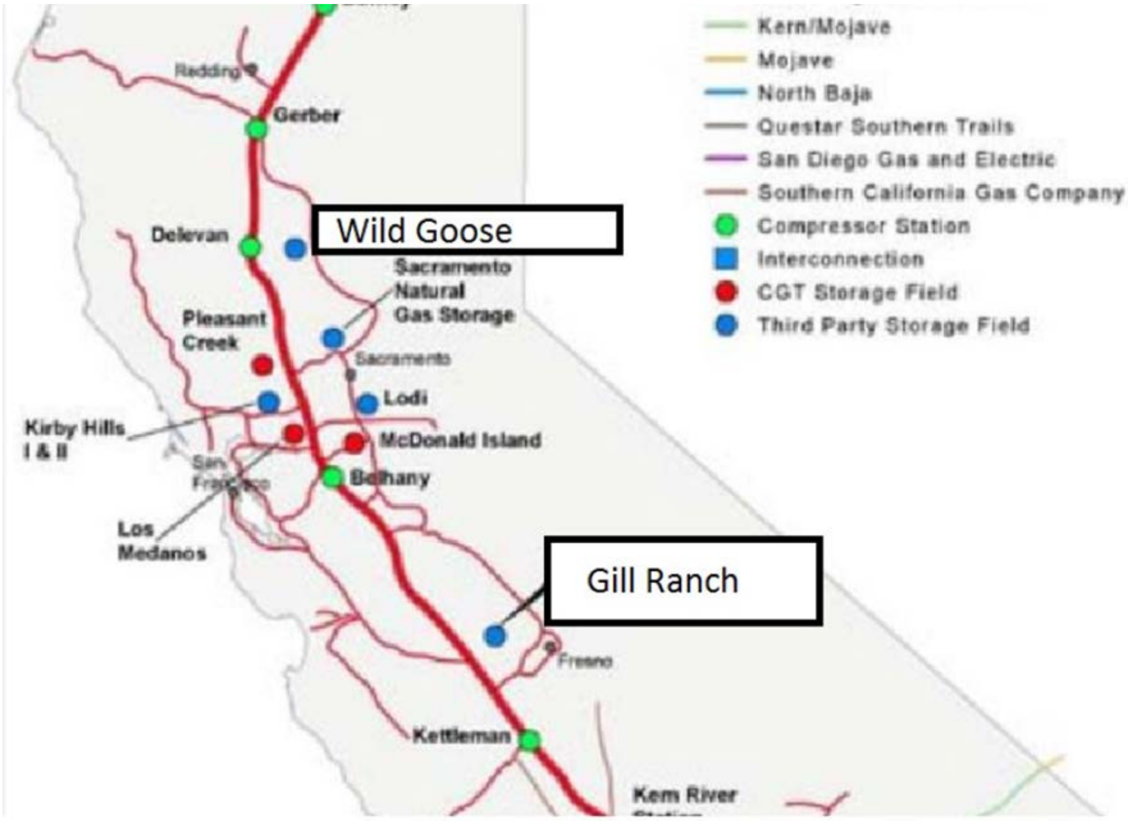


Figure 11-3: Map – Cascade Natural Gas Pipeline System

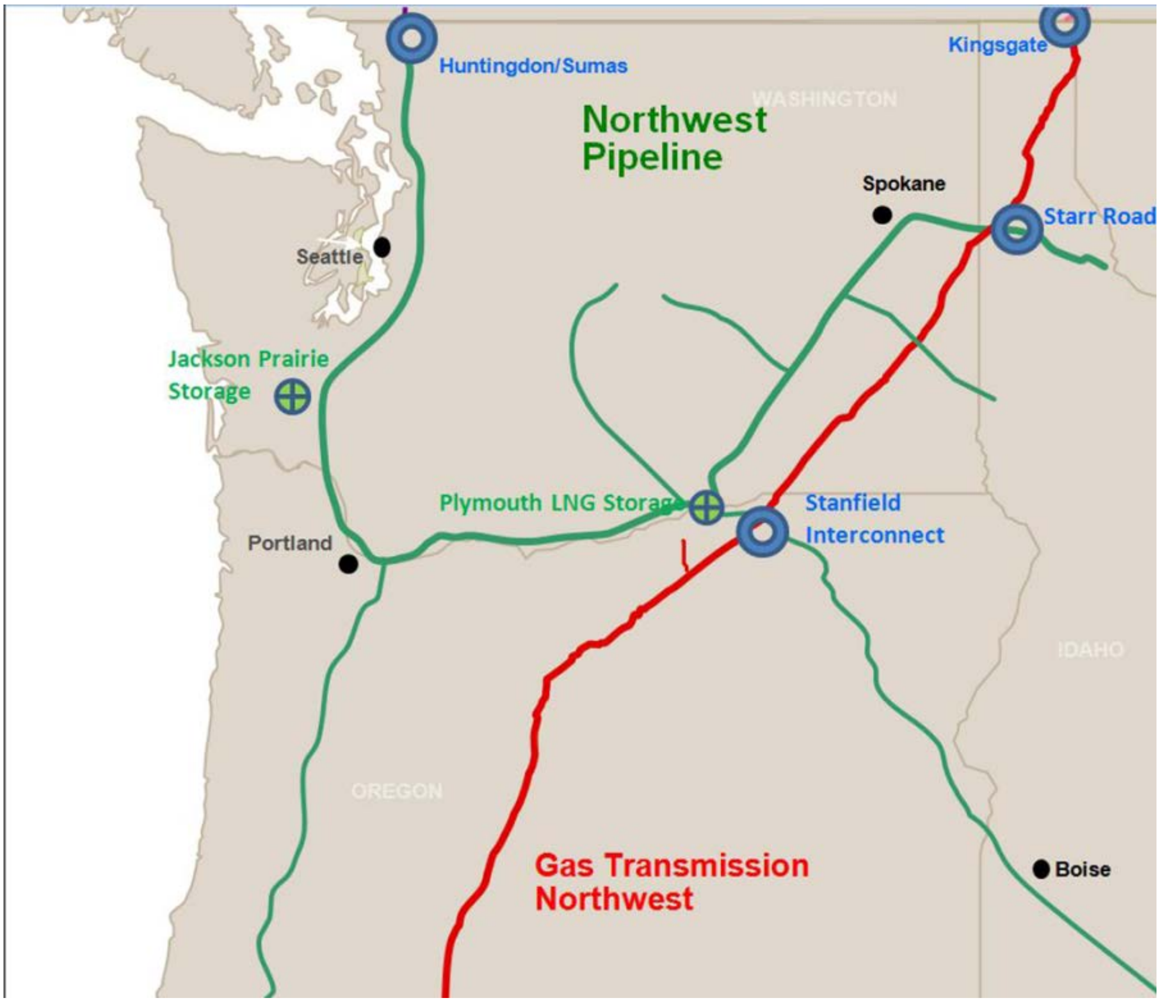


Figure 11-4: Map – Foothills-British Columbia Map

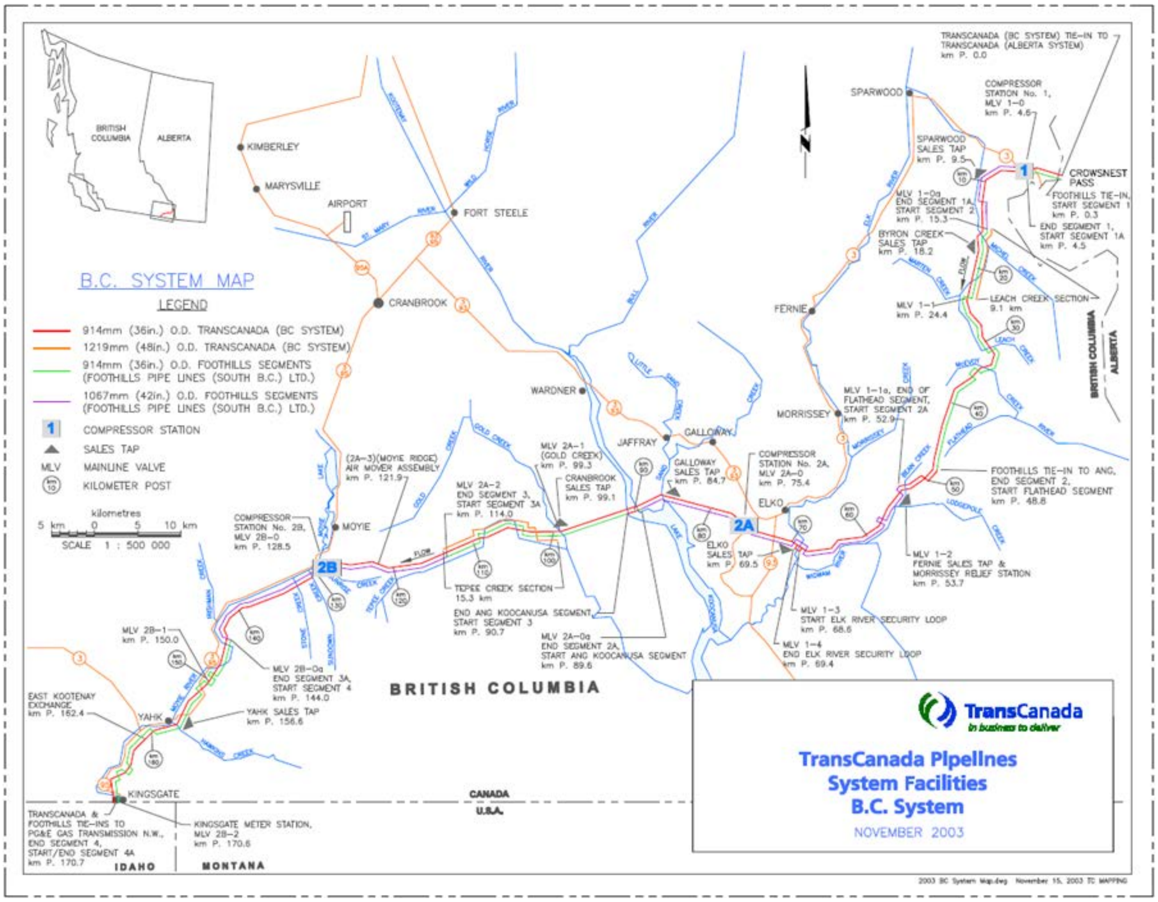


Figure 11-5: Map – Foothills-British Columbia Map 2

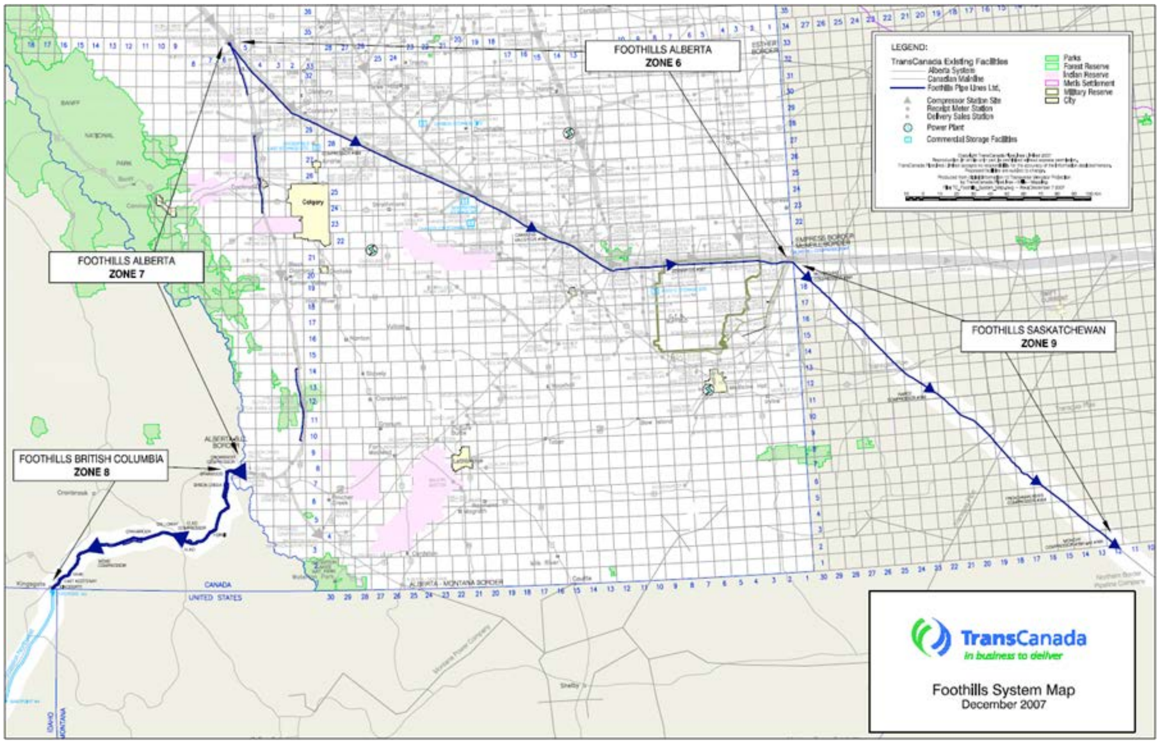


Figure 11-6: Map – GTN System Map

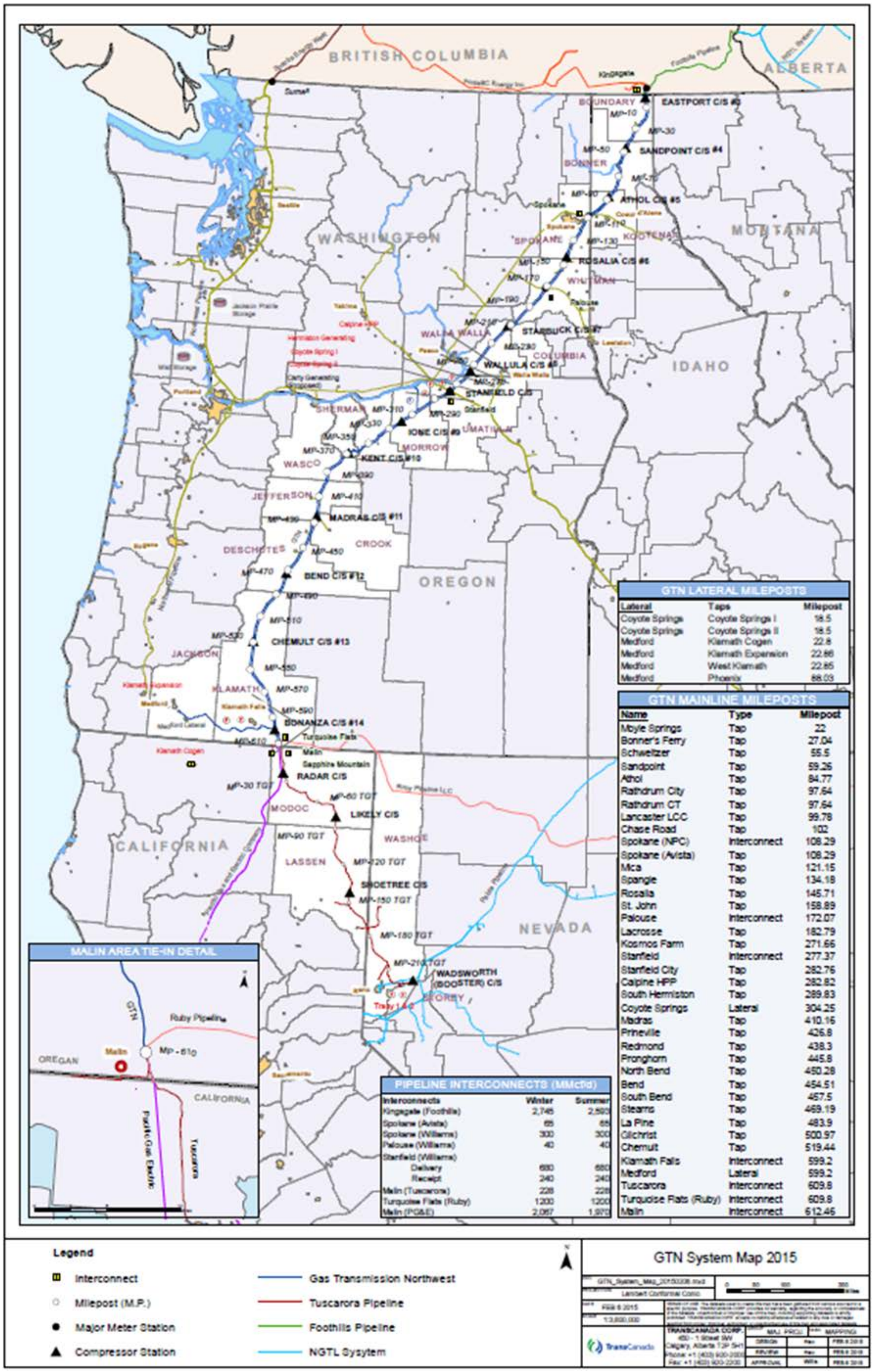
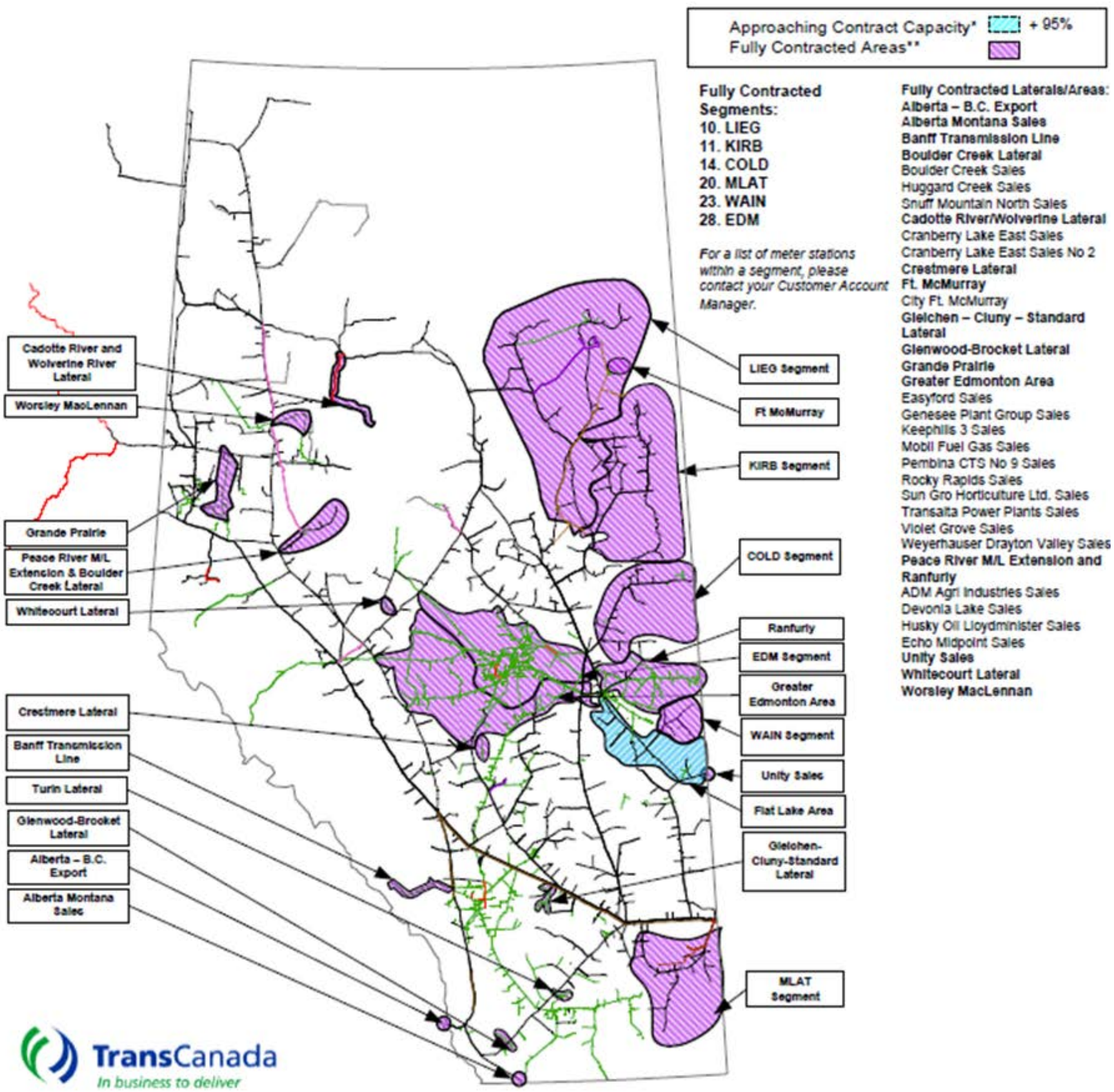


Figure 11-7: Map – NGTL Delivery System Map

TransCanada's NGTL System FT-D Availability Map
as of September 9, 2016

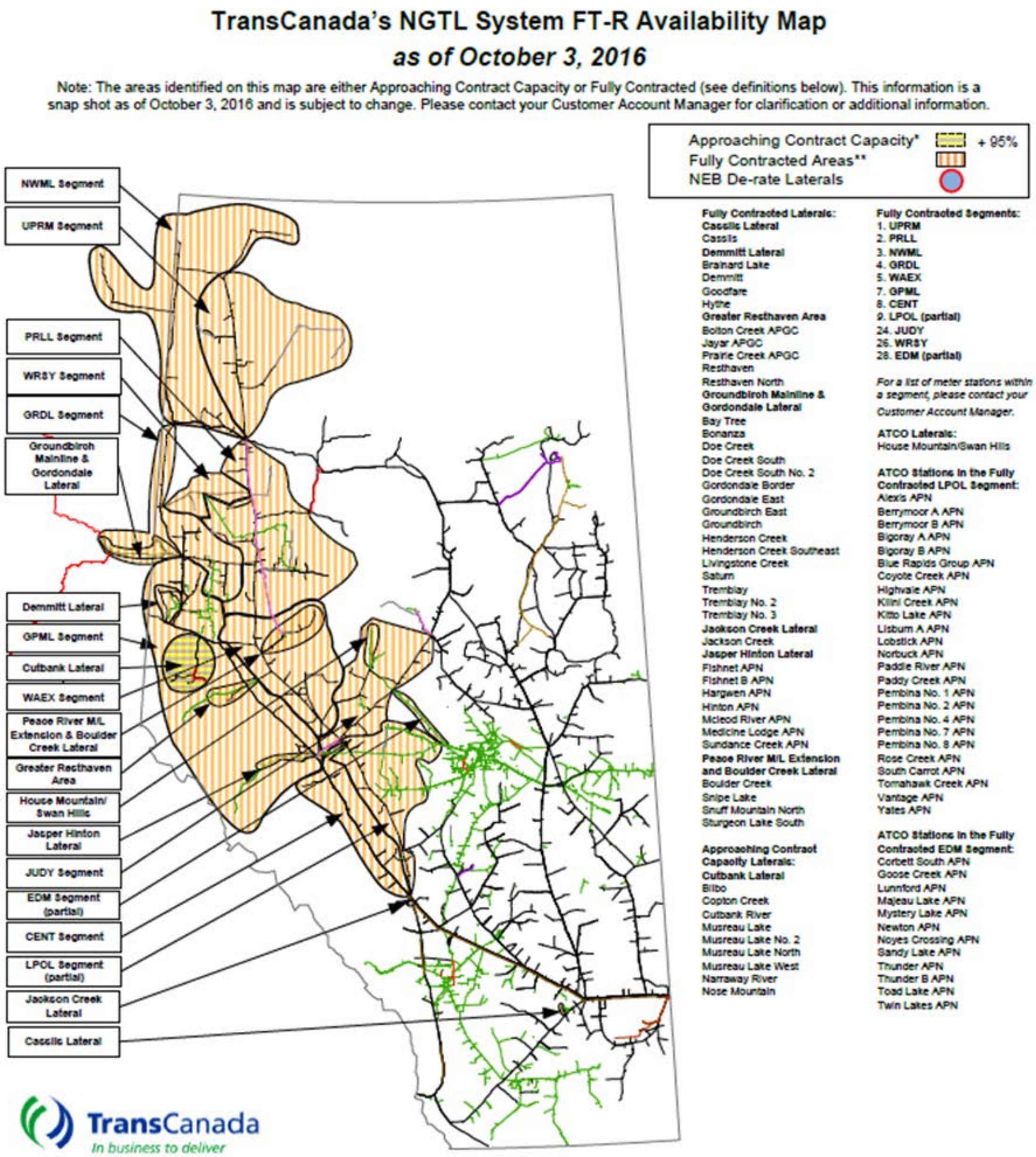
Note: The areas identified on this map are either Approaching Contract Capacity or Fully Contracted (see definitions below). This information is a snap shot as of September 9, 2016 and is subject to change. Please contact your Customer Account Manager for clarification or additional information.



Approaching Contract Capacity*	Contracts are greater than 95% of the area or facility capability. It is recommended that Firm Transfers or New Firm Contracts be confirmed with TCPL Customer Sales.
Fully Contracted**	Area is fully contracted. Firm Transfers allowed within restricted area; upstream at 1 to 1 ratio and downstream at determined hydraulic equivalence. New requests for Firm Transportation service will be held pending availability of Area capacity. For additional information refer to the Informational Postings on Customer Express, Delivery Capacity Update – **September 9, 2016.**

Capacity within any portion of the NGTL System can become fully contracted at any time and without prior notice. NGTL encourages customers to review their FT-D requirements to ensure that their FT-D levels align with their expected flow requirements.

Figure 11-8: Map – NGTL Receipt System Map



Approaching Contract Capacity*	Contracts are greater than 95% of the area or facility capability. Firm Transfers or New Firm to be confirmed with TCPL Customer Sales.
FTR Fully Contracted**	Area is fully contracted. Firm Receipt Transfers allowed within restricted area; downstream at 1 to 1 ratio and upstream at determined hydraulic equivalence. Non-renewable firm service (FT-RN) may be available. For additional information refer to the Informational Postings on Customer Express, Project Area Receipt Capacity Update – July 27, 2016.
Capacity within any portion of the NGTL System can become fully contracted at any time and without prior notice. NGTL encourages customers to review their future FT-R requirements to ensure their FT-R levels align with their expected flow requirements.	

Figure 11-9: Map – NWP North System Map

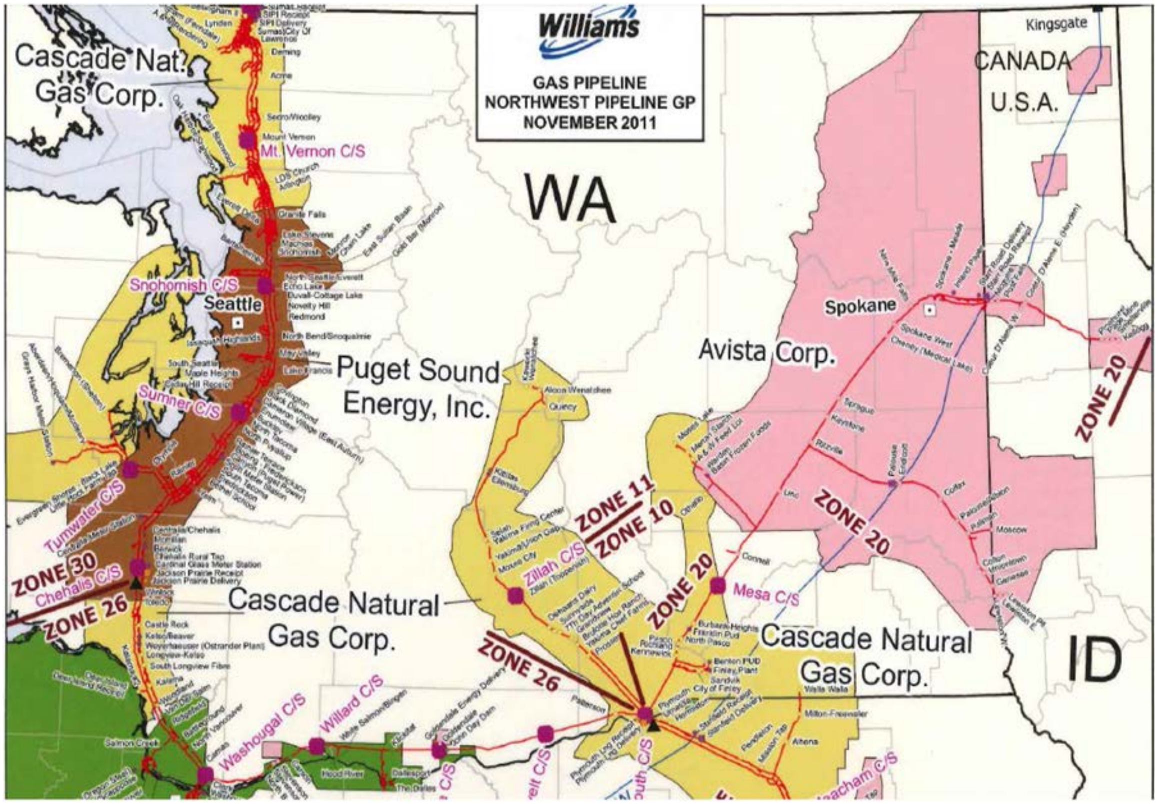


Figure 11-10: Map – NWP South System Map

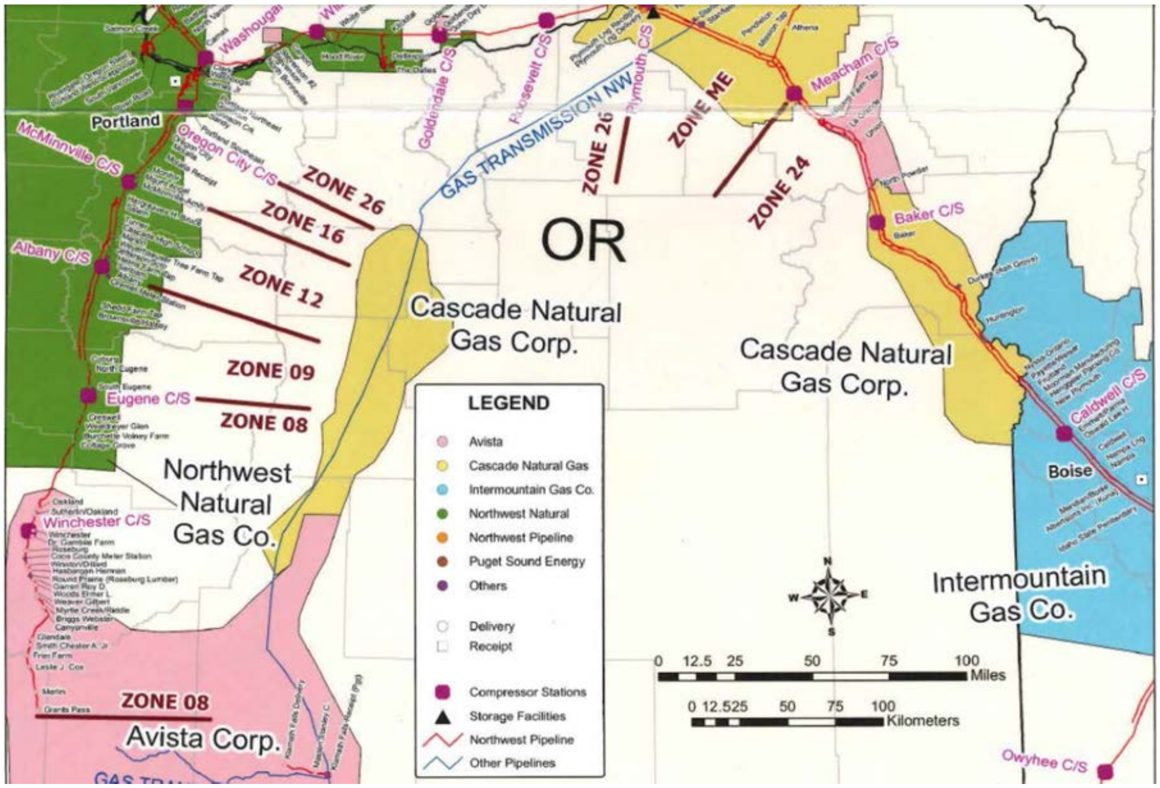


Figure 11-11: Map – Westcoast Sectional Map

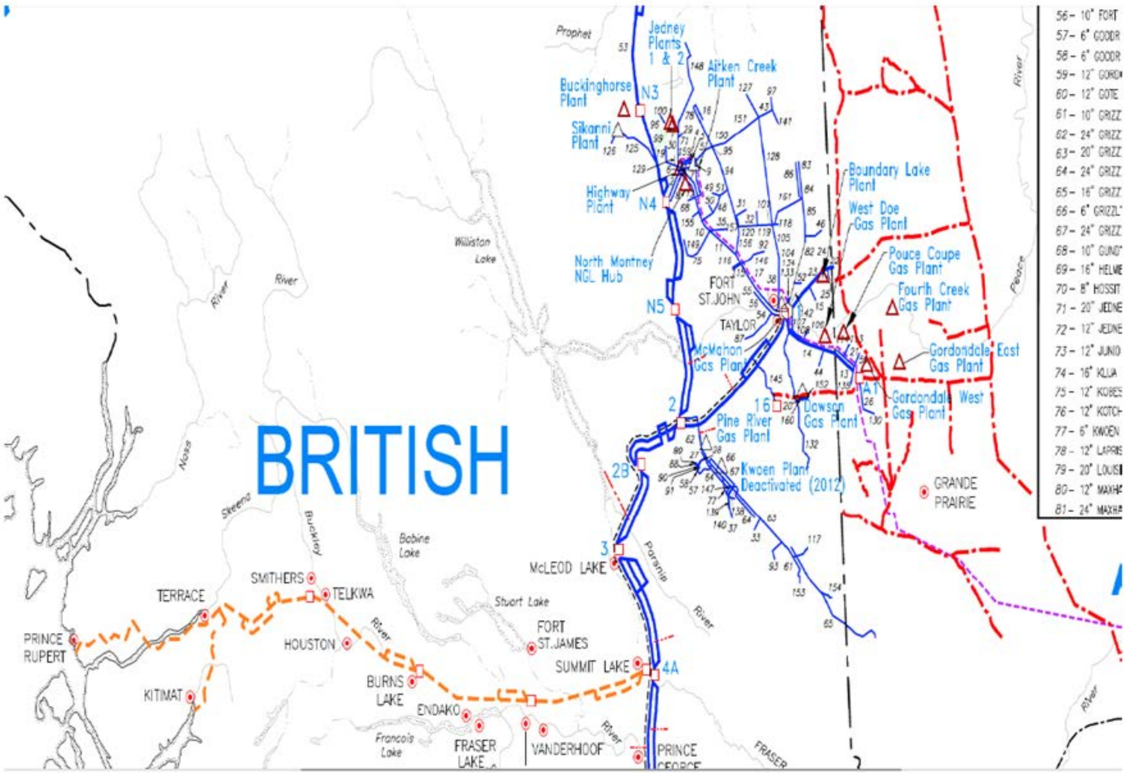


Figure 11-12: Map – Western U.S. and Canadian Pipeline Map

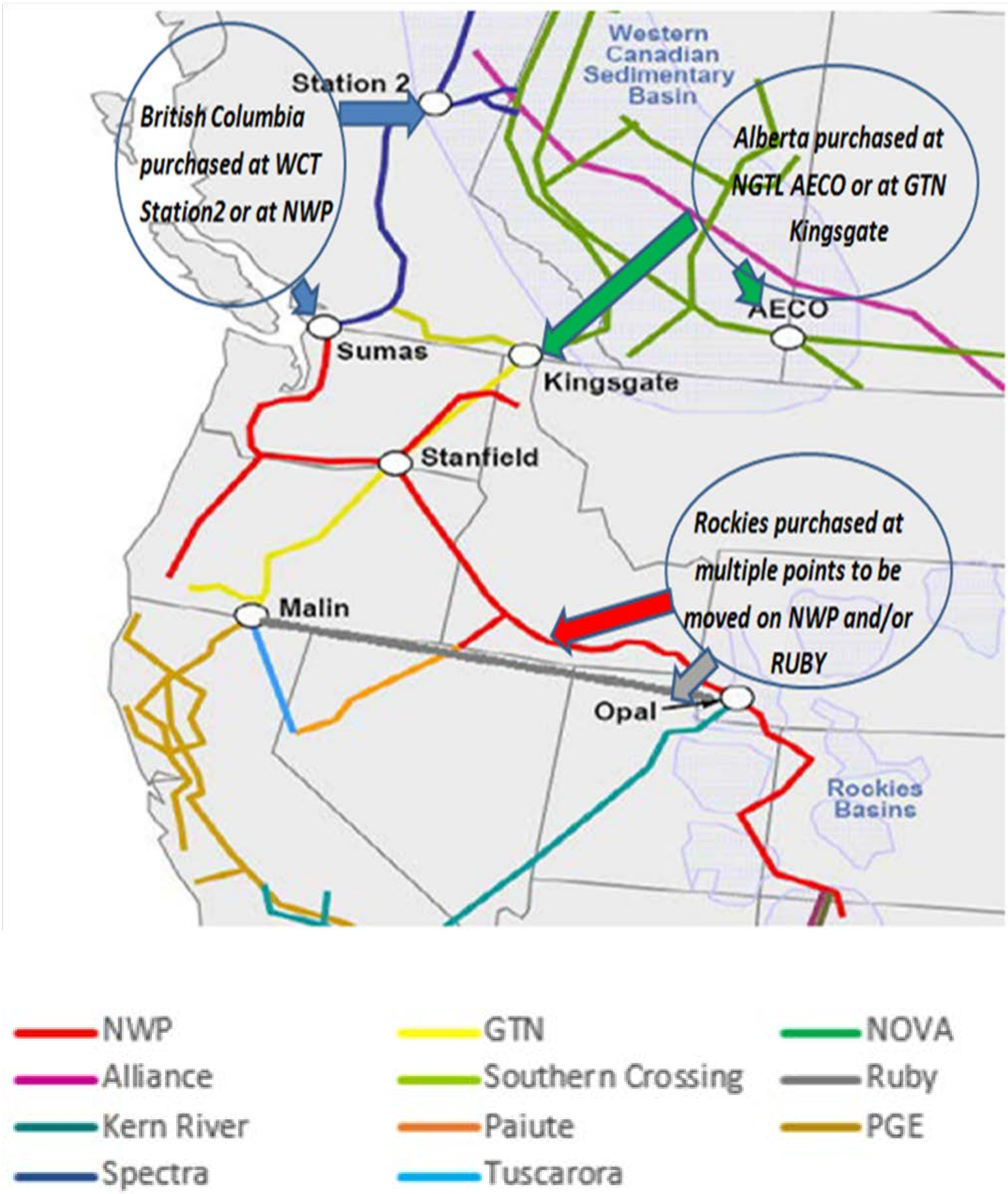
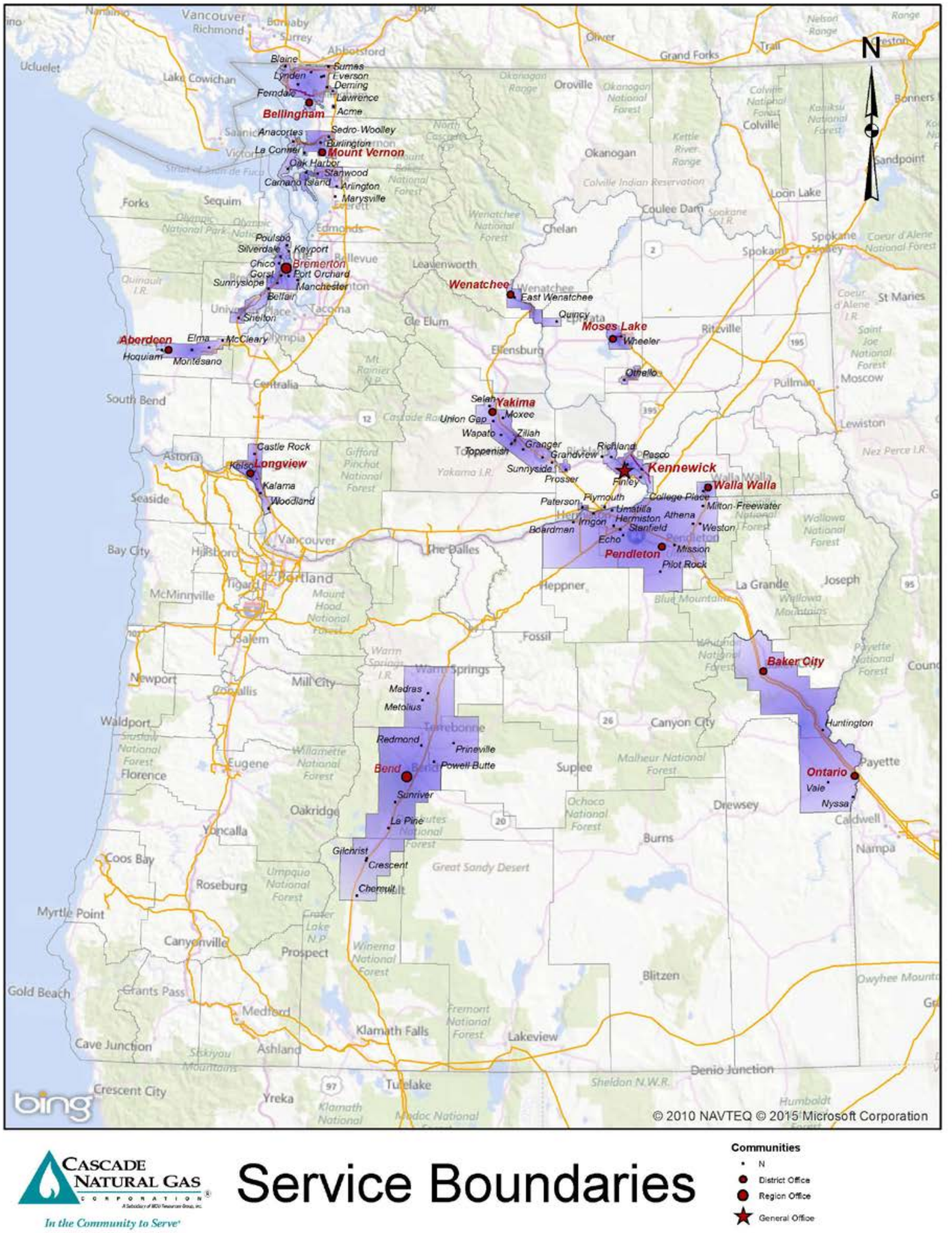


Figure 11-13: Map – Certificated Service Areas as Specified in RCW 80.28.190



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