CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

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Ms. Vickie Bailey Goggins
Oregon Public Utility Commission
550 Capitol Street NE
Salem, OR 97310-1380

RE: Cascade Natural Gas Corporation's 2011 Integrated Resource Plan Filing, Addendum/ Replacement filing

Today, Cascade Natural Gas Corporation is filing a replacement of the following sections of the Company's 2011 Integrated Resource Plan ("IRP") via e-filing:

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- Section 1 – Executive Summary
- Section 2 – Introduction & Planning Overview
- Section 3 – Demand Forecast
- Section 4 – Distribution System Enhancements
- Section 5 – Supply Side Resources
- Section 6 – Demand Side Resources
- Section 7 – Resource Integration

If you have any questions regarding the Company's IRP filing, please contact me via email at mark.sellers-vaughn@cngc.com or by telephone at (509) 734-4589.

Sincerely,

Mark Sellers-Vaughn
Manager, Supply Resource Planning

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Section 1

Executive Summary

Cascade's resource planning continues to focus on ensuring that the Company can meet the needs of our firm gas sales customers in a way that minimizes costs over the long term. Although some pipeline area zones indicate potential shortfalls, in aggregate, through 2012, Cascade has sufficient upstream pipeline capacity. However, as we move past the 2012-2013 winter heating season, primarily as a result of Cascade's growth in its residential and commercial customer base, Cascade's capacity will fall short of its design peak day demand forecast. As a result, Cascade is entering a period where it will need to acquire additional resources to meet the growing needs of these core customers. The following summarizes key findings from this plan.

Adequacy of Gas Supply

Physical gas supply is expected to be adequate to meet growing demand in the Pacific Northwest and North America. New supply development technologies continue to provide additional resources in British Columbia and the Rocky Mountain regions. Shale gas from the Horn River Basin, Montney and Marcellus are likely to keep sufficient supplies available in North America. Several sources believe that shale is set to comprise more than a third of the US production by the mid 2020s. Well performance in the Horn River play has improved over the past few years. Although players must overcome a multitude of challenges, including a remote operating environment, water availability and disposal issues, infrastructure constraints, and high upfront capital costs, Canadian production and exports are anticipated to decline.

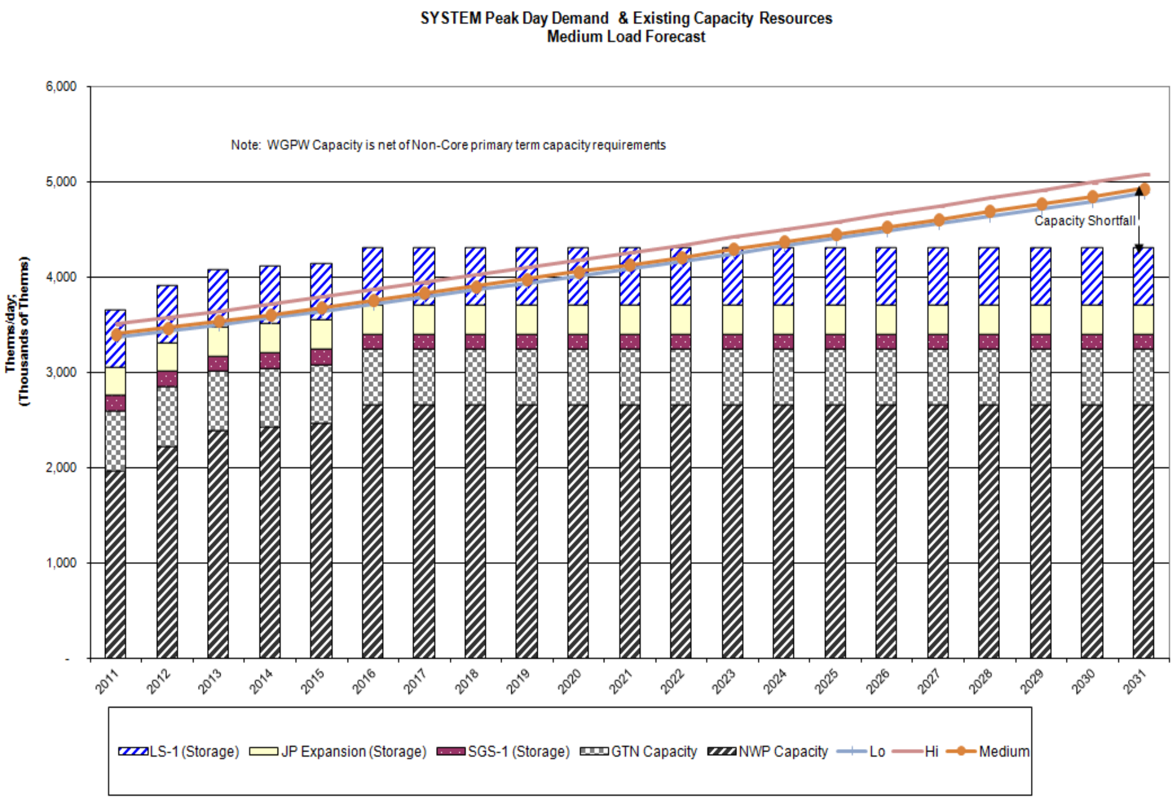
Still, due to on-going financial and regulatory issues, there is still some question as to whether or not a new pipeline will transport Alaskan gas into the North American market, or if it will be completed within the Company's planning period. The Mackenzie Gas Project, which would bring gas from the Canadian Arctic to Alberta, has pushed out its start date to 2018 (from 2014) due to regulatory issues, incomplete financial arrangements and staffing shortages. The Alaska pipeline project, designed to deliver 4.5 (up to 5.9 Bcf/d under maximum compression) Bcf/d from Alaska's North Slope into Alberta and/or the US Lower-48, is not dead, with two competing projects still officially in the works. The TransCanada-ExxonMobil Alaska Pipeline Project is expected to file its draft Resource Reports to FERC in the coming months, although, like many projects—it may expand to include an LNG option. Still, Lower-48 shale development has called into question the ultimate need for this project but indicators are that eventually it will get done around 2023.

Load Resource Balance

During this planning cycle, Cascade continued to evaluate the impacts on both its load and resources and portfolio costs associated with its peak day planning criteria. Until the 2008 IRP, Cascade had historically utilized a system average of 65 heating degree days (DD) for its peak demand forecast as it represented the coldest day recorded in Cascade's 60 plus years of weather history. However, the Company had only experienced a 65DD once in its history (which occurred in 1968), and therefore commencing with the 2008 Plan, the Company modified its design day criteria to utilize the coldest day during the past 30 years. This modification reduced the peak day to 61DD which occurred as recently as 1990.

The following graph shows the peak day requirements compared to the Company's existing pipeline capacity resources under the various load growth forecasts. Shortfalls in the 2010/2011 period will be met through citygate peaking resources.

Figure 1-A



Analytical Methods

Cascade continues to utilize the SENDOUT™ model to assist with the analysis of resource alternatives. SENDOUT™ is a linear optimization model that helps identify the long-term least cost combination of resources to meet stated loads. The model determines the optimal portfolio of resources that will minimize costs over the planning horizon based on a set of assumptions regarding resource alternatives, resource costs, demand growth and gas prices. Linear optimization models, such as SENDOUT™, are basically deterministic. In other words, they solve the "least cost problem" based upon the assumptions provided to the model. As a result, the Company, beginning with its 2007 IRP, expanded its uncertainty analysis through the purchase of Vector Gas™ (an add-on product) that facilitated the ability to model gas price and load (driven by weather) uncertainty. The Monte-Carlo functionality was integrated in SENDOUT™ Version 12.5, which is the platform that Cascade used to prepare its integration analysis. The Monte-Carlo modeling capability provides additional information to decision-makers under conditions of uncertainty. The Monte-Carlo analysis was used in this plan to test the physical and financial risks associated with the optimal portfolio from the basecase planning scenario. This tool provides a valuable enhancement to the robustness of the Company's resource planning.

Generic Resources

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 MIST and AECO, additional transportation capacity on both Williams and GTN pipeline systems, several of the proposed pipelines to move Rockies gas to the northwest, along with on-system satellite LNG facilities, biogas, 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' worth 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.

Analytical Framework

Traditional integrated resource planning would include analyses targeted at identifying the optimal long-term resource portfolio to meet the demand of the gas utility's customers across a few customer growth and gas price scenarios. In this plan, Cascade's resource analysis includes 8 different scenarios that focus solely on gas utility operations. In addition to scenario analysis, Cascade performed two different kinds of Monte-Carlo analyses to examine a variety of risks as noted above.

Summary of Key Findings

- Cascade anticipates its core customer base will continue to grow over the planning horizon and annual throughput is anticipated to increase between 1.181% and 1.49% per year.

- The projected costs for natural gas have declined significantly and long-term prices are estimated to range between $3.75 to $6 over the planning horizon compared to the $8 to $13 forecasted in the 2008 IRP. This improvement to the long-term gas supply outlook is a stark contrast to the diminishing supply outlook that was prevalent during the development of the Company's 2008 IRP.

- The basecase results indicate energy efficiency programs with a levelized cost of 70 cents per therm or less are cost-effective over the planning horizon, with the price uncertainty analysis indicating that the levelized costs will likely range between 64 to 79 cents per therm. However, if carbon legislation is established during the planning horizon similar to that described in Section 6, the cost-effectiveness limits could increase between 8 to 16 cents depending upon the level of the costs and the timing of the implementation.

- As described in Section 6, the conservation potential analyses indicate that over the 20 year planning horizon the technical potential associated with cost effective conservation measures is 23,193,554 therms in Oregon and 44,275,021 therms in Washington for a combined total of 67,468,575 therms.

- Even with energy efficiency programs, 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. On September 1, 2010 Williams announced that the Blue Bridge I-5 corridor project had been shelved, and with uncertainty surrounding the likelihood of Palomar being built, Ruby Pipeline is emerging as a possible transportation resource to bring Rockies supplies to central Oregon, via Malin and backhaul service on GTN. Ruby went on line this year and has been running at near capacity since its in-service date. Utilizing the SENDOUT™ resource optimization model, several scenarios were run to test the viability of acquiring Ruby capacity either based on existing recourse rates, discounted rates and via capacity release through a third party. Incremental and corresponding GTN Malin north capacity was also modeled at recourse (secondary firm) and higher pricing levels. Basin prices in the model over the 20 year planning horizon have Rockies trading at a slight discount to AECO, Malin and Sumas ($0.06 - $0.15). Regardless of the scenarios modeled, SENDOUT™ consistently selected Ruby capacity in a range of 17,000 to approximately 19,000 dths/day.

- Many of the proposed pipeline projects will not be viable resources for some time. In the interim, capacity shortfalls will be met through the use of peaking and citygate gas supply deliveries which will utilize third-party (non-Cascade) upstream pipeline transportation.

- Satellite LNG facilities that are located within Cascade's distribution system are also attractive alternatives. Satellite LNG may alleviate the need for incremental pipeline capacity and to the extent the facility could be strategically located on a portion of the distribution system, it could provide the further benefit of eliminating or reducing distribution system constraints. Cascade has considered bio natural gas (BNG) as an alternative, but at the time of this writing, there are no viable projects available to our distribution territory. Regardless, prior to any BNG supplies being added to the portfolio, gas quality issues will need to be satisfactorily addressed. In addition to Cascade, upstream pipelines, such as Northwest Pipeline are beginning to address gas quality issues regarding BNG. We will continue to monitor our market intelligence sources to see if viable BNG opportunities develop.

- None of the proposed LNG projects are within Cascade's distribution system. Many of the initially proposed LNG import facilities located in the Pacific Northwest (Bradwood Landing, Jordan Cove) would require backhaul capability or additional infrastructure on upstream pipelines in order to reach Cascade's distribution system. However, each of these facilities appears to be looking to export as opposed to import. This has made it questionable whether or not to include these as alternative resources as part of the 2011 IRP. Cascade was faced with a similar situation regarding LNG--prior to September 19, 2008, LNG supplies sourced at Kitimat were selected as part of the least cost-portfolio mix, however, on September 19, 2008, Kitimat LNG announced that the development focus of the facility would switch from a regasification to a liquefaction facility, making Kitimat an exporter, rather than an importer of natural gas. Kitimat did leave open the possibility of providing regasification in addition to liquefaction. As of this writing, it appears that Kitimat will focus on exporting natural gas, particularly given the huge supply of shale gas from northeastern British Columbia. The company did analyze the other two LNG options in the Northwest (Bradwood and Jordan Cove) along with the incremental pipeline capacity that would be necessary to reach Cascade's service territory and found that based on preliminary cost estimates that model preferred the Ruby and Malin transportation resources over the import LNG options. Since there was uncertainty about these facilities during the initial SENDOUT™ scenario model runs set up in summer 2011, we chose to leave the analysis of these facilities in the 2011 IRP. It should be noted that neither Bradwood nor Jordan Cove were selected as part of the basecase portfolio. The company will continue to monitor the impact of various imported LNG options (both import and export) and update its modeling assumptions as more information becomes available.

- 20 year portfolio costs, on a Net Present Value (NPV) basis, are expected to range between $2,448,210,000 to $3,216,376,000 for the planning period, with an average cost per therm ranging between $.354748 and $.447916.

Use and Relevance of the Integrated Resource Plan

Cascade's Integrated Resource Plan provides the strategic direction guiding the Company's long-term resource acquisition process. The plan does not commit Cascade to the acquisition of a specific resource type or facility, nor does it preclude the Company from pursuing a particular resource or technology. Rather, the plan identifies key factors related to resource decisions and provides a method for evaluating resources in terms of their cost and risk. Cascade recognizes that integrated resource planning is a dynamic process reflecting changing market forces and a changing regulatory environment.

Section 2

Introduction and Planning Overview

Company/Service Area Profile - Customers, Resource Maps

Beginning in 1953, Cascade Natural Gas Corporation began acquiring small local gas distribution companies in anticipation of the construction of an interstate pipeline to bring natural gas into the Pacific Northwest in 1956. The pipeline began in New Mexico and moved northwesterly into the northeast corner of Oregon and on into Washington, to the Canadian border near Sumas, Washington. Cascade's distribution system tapped into the pipeline at many places in Oregon and Washington. Usually, an industrial operation located in the area made it economically feasible for Cascade to construct its initial distribution system to serve the industrial customer and then branch out from there to serve the residential and commercial communities in the nearby area.

Today, Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a richly diverse economic base as well as varying climatological areas (see service area map, Figure 2-A). Cascade serves 96 communities throughout Washington and Oregon consisting of about 260,000 customers. All of the communities Cascade serves are small cities and towns. This makes Cascade unique in the gas distribution business in the Pacific Northwest. Cascade's customer base currently includes approximately 226,000 residential customers, 33,000 commercial customers, and 700 industrial customers. Cascade's sales volumes reflect the ratio of approximately 75% in Washington and 25% in Oregon.

Bundled vs. Unbundled Service

Since Cascade began distributing natural gas in the Pacific Northwest, the Company has offered its customers a “bundled” natural gas distribution service. This bundled service included purchasing the gas supply, transporting that supply to Cascade's city gate, and distributing that transported supply to each Cascade customer through the Company’s local distribution system. Customers receiving traditional bundled services are referred to as core customers. In 1989, Cascade “unbundled” its rates and as a result approximately 200 of the 700 industrial customers have elected to become "non-core" customers. These customers have made the choice to rely on alternative methods of service rather than the traditional bundled gas supply and pipeline transportation services available to core customers for their gas requirements. Therefore, providing gas supply and transportation capacity resources to non-core customers is not considered part of this Integrated Resource Plan as such resources are separate from the supply and capacity contracts for the core customers who continue to utilize Cascade’s bundled system gas supplies and capacity. Although the resource needs for non-core customers are not included in either the conservation or supply side resource analysis, their contracted peak day delivery is considered in the distribution system planning analysis discussed in Section 4.

For the Calendar year ended December 2010, Cascade's 226,000 residential customers represented approximately 13% of the total natural gas delivered on Cascade's system, while the 33,000 commercial customers represented approximately 10% and the 500 core market industrial customers consumed approximately 2% of total gas throughput.

FIGURE 2-A

The remaining 200 non-core industrial customers represented about 75% of total throughput.

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system via two natural gas pipeline companies. Williams' Northwest Pipeline GP (NWP) provides access to British Columbia and domestic Rocky Mountain gas while the Gas Transmission Northwest (GTN) provides access to Alberta gas. Cascade also holds transportation contracts upstream of these systems on TransCanada Pipeline's Foothills Pipeline (formerly ANG) and Alberta System (also known as NOVA), as well as on Westcoast Energy, Inc. (Spectra Energy).

IRP Guidelines and Policies

Cascade utilizes integrated resource planning to maximize the efficiencies of the Company's utility operations. The planning process includes an assessment of current and future gas load requirements, the possible resource options for serving the projected load requirements, and a selection of the set of least cost resource alternatives with acceptable level of reliability through the use of an optimization model. Monte-Carlo simulation tools are utilized to further analyze the results of the optimization model to quantify the range of uncertainty in market price and demand due to changes in weather.

Cascade is subject to regulatory oversight by the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utility Commission (OPUC). Each commission has established a set of guidelines or rules, which the company's plan must meet. In Washington those guidelines are contained in WAC 480-90-238 and in Oregon the guidelines are found in the Commission Order No. 07-002 in docket UM 1056. In general, both Commissions' guidelines require that the utility develop a range of demand forecasts, examine all feasible resources for meeting that demand whether they are supply-side or demand side and compare them on an equal basis, considering the uncertainty over the planning horizon, develop a 2 year action plan and involve the public and the various stakeholders in the planning process.

Cascade believes that its IRP meets the substantive requirements of both the Washington and Oregon Commissions. This IRP includes a range of demand forecasts that encompass the anticipated forces, both economic and weather-driven, that will impact the load forecasts over the planning horizon. The demand side resource section includes an assessment of technically feasible improvements in the efficient use of natural gas. The supply resource section includes a discussion of the supply side resource options available including an assessment of conventional and commercially available non-conventional gas supplies, an assessment of opportunities for additional company-owned and contracted storage, and an assessment of the Company's existing pipeline transportation capability and reliability along with the opportunity for incremental pipeline transportation resources. The integration section provides a comparative evaluation of the cost of the various resource options on a consistent and comparable method. The resource integration section also describes the integration of the demand forecast and resource evaluations into a long range resource plan describing the strategies designed to reliably meet current and future needs at the lowest reasonable cost to Cascade's ratepayers. The short-term action plan describes the specific actions the utility will take to implement the long-range integrated resource plan during the next two years and reports on the Company's progress in meeting its prior 2-year action plan goals.

Cascade believes all resources described in this IRP have been evaluated on a consistent and comparable basis through the use of its optimization model. Uncertainty has been considered in each component of this plan. The demand forecast includes a reasonable range of uncertainty as quantified in the low, medium and high load growth scenarios along with the additional simulation analysis calculated through SENDOUT's™ Monte-Carlo functionality that assesses the impacts of weather on the load forecasts. The demand side and supply side resource sections describe relative uncertainties regarding reliability, cost and operating constraints and external costs. Uncertainties associated with the environmental effects of carbon emissions have also been included through an analysis of the impact of carbon legislation on the portfolio. Price volatility and market risks and their impacts on the Company's long-term resource portfolio have been assessed through the use of the SENDOUT™ model.

To involve public interests in the development stages of this IRP, Cascade has a Technical Advisory Group (TAG). Three meetings were held to discuss the major IRP topics including the demand forecast, distribution system planning, demand side resources, supply side resources, and resource integration and uncertainty analysis. The TAG meetings were helpful to Cascade as questions were answered and varying points of view were explored. Appendix A-2 contains an outline of the meeting content, a list of participants and the presentation materials.

Appendix A-3 provides additional information regarding the specific requirements or guidelines for each commission and how the company has met those requirements.

Resource Decision Making Process Overview

Cascade makes resource decisions based on the best quantitative and qualitative information available. The IRP tools that are continually evolving assist Cascade in formulating energy resource decisions in a logical, consistent and comparable manner. The steps outlined below are those utilized by Cascade for both its short-term and long- term resource decisions:

1. Construct a range of possible demand forecasts for the core market.

2. Calculate avoidable distribution system enhancement costs.

3. Provide the optimization model the existing supply side and demand side resource options need to meet demand.

4. Run the optimization model to identify resource needs including the types of resources and their timing requirements. The existing portfolio is modeled under a range of demand forecast conditions.

5. Identify incremental supply and demand side resources to satisfy a range of incremental growth scenarios.

6. Run the optimization and Monte-Carlo simulation models to assist in determining the best- fit portfolio given an expected range of forecasted core loads and operating conditions.

The resource decision-making process is dynamic and ongoing and the Company's resource strategy must constantly evolve to reflect dynamic market forces and a continually changing regulatory environment. This IRP document represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions as conditions will change over the planning horizon and will impact areas covered by this IRP. Rather, this document is meant to describe the currently anticipated conditions over the long-term planning horizon, the anticipated resource selections and most importantly the process for making resource decisions.

Disclaimer –Important notice

Cascade makes the following cautionary statements in its Integrated Resource Plan and appendices to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or on behalf of Cascade. This Plan, its appendices, and any amendments or supplements to it, includes forward-looking statements, which are statements of expectations, beliefs, plans, objectives, and assumptions of future events or performance. Words or phrases such as “anticipates”, “believes”, “estimates”, “expects”, “intends”, “plans”, “predicts”, “projects”, “will likely result”, “will continue” or similar expressions identify forward-looking statements.

Forward-looking statements involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed. Cascade’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis; however, there can be no assurance that Cascade’s expectations, beliefs or projections will be achieved or accomplished.

Any forward-looking statement speaks only as of the date on which such statement is made and except as required by law, Cascade undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. These materials and any forward-looking statements within them should not be construed as either projections or predictions or as business, legal, tax, financial, or accounting advice and should not be relied upon for any such purpose.

Section 3

Demand Forecast

Each year Cascade develops a 20-year forecast of customers, therm sales and peak requirements for use in short (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.

Forecast Methodology

Cascade begins the forecast process by developing three separate econometric models for each of the Company's 15 districts. Three models for each district, for a total of 45 models, predict customer counts in the three main core customer classes – residential, commercial and industrial. Models are built from the district level up as it is the smallest level at which there is a high degree of consistency and availability of raw data. This is a change of methodology from previous years where certain models were built from the town level and others from the district. The unification of methodologies is expected to increase reliability of the forecast. The district models are rolled up into zones which segregate Cascade's system based on pipelines and weather (see Appendix C).

In addition to these 45 customer count forecasting models, a separate and parallel set of 45 models is developed to estimate per-customer therm usage for each customer class in each district. A multiplicative combination of the customer count and therm usage models is Cascade's annual load projection.

Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short and long term. Indicators included in the model include: employment and household count forecasts, mortgage rates (for residential customer counts) and the prime rate (for commercial and industrial customer counts). Therm forecasts are constructed from median household income forecast, weather and natural gas prices. Economic indicator forecasts are supplied by Woods & Poole. Mortgage and prime rates are forecast by Cascade using base data provided by Freddie Mac and the Federal Reserve, respectively. Past weather is sourced from NOAA and future weather is Cascade's 20-year normal developed for the Company's last rate case. Natural gas prices are provided by Wood Mackenzie and equal weights are assigned to the AECO, NYMEX and SUMAS indexes based on Cascade's general portfolio mix (Appendix E). These indicators and the functional forms illustrated below were chosen over others as they were the most consistent in returning statistically valid results. Historical data used in the regression extends back up to 1980 for customer counts and 1994 for therms.

$$RESc_{t,d} = f\left(employment_{t,d}, households_{t,d}, mortgage\ rate_{t,d}\right)$$
$$COMc_{t,d}, INDc_{t,d} = f\left(employment_{t,d}, households_{t,d}, prime\ rate_{t,d}\right)$$
$$RESt_{t,d}, COMt_{t,d}, INDt_{t,d} = f\left(HDDs_{t,d} + MHI_{t,d} + NG\$_{t,d}\right)$$
$$Load_{year} = \sum_{d=1}^{15} RESc_{t,d} * RESt_{t,d} + COMc_{t,d} * COMt_{t,d} + INDc_{t,d} * INDt_{t,d}$$

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 by altering Woods & Poole's forecasts to reflect Cascade's service territory's strongest and weakest performing decades over the last 30 years (Appendix B). These scenarios, along with the original best-estimate mid case scenario, encapsulate a range of most-likely possibilities given known data. Based on historical experience, Cascade expects system load will likely remain within a range bounded by the low and high growth scenarios.

Peak Day Forecast

In order to ensure satisfaction of core customer demand on the coldest days, Cascade develops peak day usage forecasts in conjunction with annual basis 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 of days in the event gas does not flow.

Historically Cascade has developed peak day forecasts based on a 65 HDD day (0°F) to reflect the coldest day in Cascade's 60-year weather history. Cascade's 2008 IRP changed this practice to reflect the coldest day during the past 30 years. This record is held by December 21, 1990 at 61 HDDs. The peak day forecast is developed by adjusting the therm usage on the coldest day in recent history (January 5, 2004 at 56 HDD) upwards to an estimate of what therm usage would have been had that day been 61 HDD. The therm usage is then applied to each district and escalated into the future at the forecast therm usage annual growth rate.

This method rests on the assumption that core market load shape does not significantly change throughout the forecast horizon. Cascade believes that the peak day forecast conservatively overestimates peak day usage as the base forecast does not explicitly include future conservation measures implemented by customers that would act to increase energy efficiency and reduce therm day usage.

Forecast Results

Load growth across Cascade's system through 2030 is expected to fluctuate between 1.5% and 1.7% annually, with lower, recessionary growth in the short term. Load growth consists of a split between residential and commercial demand, with a slow decline in industrial demand.

Table 3-1: Expected Load Growth by Class

	Residential	Commercial	Industrial	System
2011 – 2016	1.71%	1.68%	-3.22%	1.48%
2016 – 2021	1.78%	1.81%	-1.85%	1.66%
2021 – 2026	1.74%	1.83%	-1.06%	1.68%
2026 – 2031	1.50%	1.59%	-1.24%	1.46%
2011 – 2031	1.68%	1.73%	-1.84%	1.57%

In absolute numbers, system load under normal weather conditions is expected to reach 412 million therms in 2030, up from an estimate of 300 million for 2011. A majority of core load today is residential. Not only will this continue into the future, but since residential load growth is expected to be higher than commercial and industrial, residential customers will experience a slightly increased profile on Cascade's system.

Figure 3-1: Relative Expected Load by Class

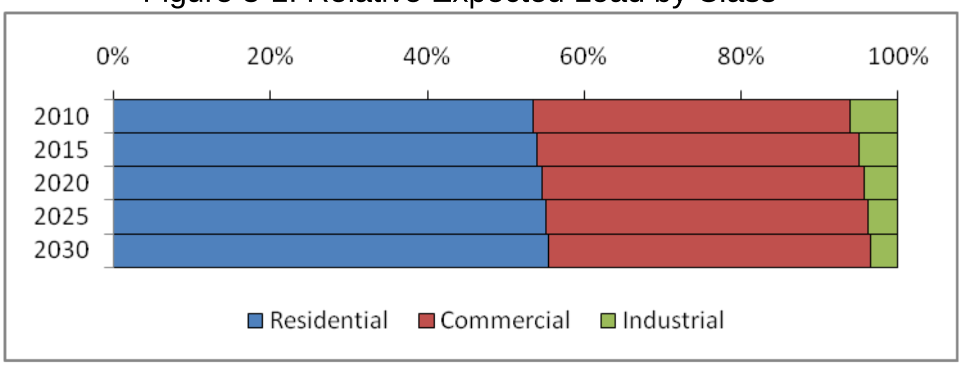


Table 3-2: Expected Load by Class

	Residential	Commercial	Industrial
2011	163,007,592	122,912,569	13,931,851
2016	177,442,906	133,565,259	11,822,190
2021	193,769,389	146,098,658	10,767,863
2026	211,207,260	159,939,319	10,202,021
2031	227,541,615	173,091,273	9,586,154
2011 - 2031	39.6%	40.8%	-31.2%

Residential and commercial load growth is primarily a result of increased customer counts. The number of residential and commercial customers is expected to increase faster than therm usage. Several factors are believed to be the cause of this phenomenon; among them are soft conservation, building codes and heat pump penetration. This reduction is more prevalent among residential customers than commercial.

Table 3-3: Expected Customer Counts by Class

	Residential	Commercial	Industrial
2011	230,833	34,618	441
2016	255,767	38,204	400
2021	282,006	41,954	377
2026	309,492	45,861	365
2031	338,158	49,908	361
2011 - 2031	46.5%	44.2%	-18.2%

Core industrial load and customer counts are a more complex and difficult to distill story. First, industrial users in Cascade's service territory are subject to the same overarching economic conditions that industry elsewhere in the United States has been experiencing. A slow but steady economic shift away from manufacturing towards the service industry is reflected in lower industrial load and less industrial customers. Second, industrial customers may be faced with consolidation and mergers, which would reduce customer counts faster than per customer therm usage. Third, within the historical data period used to develop the industrial customer econometric models was the introduction of unbundled service. With unbundling, many industrial customers have switched to non-core, a trend that will continue into the future. For this reason, the 18% reduction in core industrial demand does not necessarily indicate that industry in Cascade's service territory is in a state of distress.

Table 3-4: Expected Reduction in Therm Usage per Customer

Year	Residential	Commercial	Industrial
2011	706	3551	31590
2016	694	3496	29553
2021	687	3482	28565
2026	682	3487	27959
2031	673	3468	26581
2011 - 2031	-4.7%	-2.3%	-15.9%

Geography
Load across Cascade's two-state service territory is expected to increase 37%, with the Oregon portion outpacing Washington at 41% versus 35%.

Table 3-5: Expected Load by State

	Washington	Oregon	System
2011	228,027,758	73,858,065	301,885,823
2016	246,062,671	78,801,495	324,864,165
2021	266,601,645	86,068,075	352,669,721
2026	288,322,552	95,059,860	383,382,411
2031	308,136,988	104,108,821	412,244,144

Within Oregon, the Bend area is expected to grow significantly faster than the rest of Eastern Oregon. Pendleton is expected to grow faster than Cascade's Baker/Ontario region, which is expected to experience minimal growth.

Table 3-6: Oregon 20-Year Load Growth by District

20-Year Load Growth	
Baker	0.5%
Bend	54.5%
Ontario	-4.0%
Pendleton	22.1%
Oregon	41.0%

Peak Day
Residential customers have higher temperature sensitivity than commercial or industrial. Because of their increasing profile on Cascade's system over the coming 20 years, weather-sensitive peak demand will increase faster than annual load. 2010 load on 61 HDDs is expected to be 3.6 million therms, rising to 5.4 million by 2030. Peak day load will increase at 2.0% annually while annual load will increase by 1.6%.

Table 3-7: Expected Peak Day Growth and Therms

	Peak Growth	Annual Load
2011 -2016	2.08%	1.48%
2016 -2021	1.98%	1.66%
2021- 2025	1.88%	1.68%
2026 -2031	1.78%	1.46%
2011 - 2031	1.93%	1.57%

	Peak Day Therms
2011	3,681,099
2016	4,080,989
2021	4,501,149
2026	4,940,461
2031	5,397,372

High and Low Scenarios

High and low scenarios were created by examining the best and poorest performing years from the historical data period, 1980 to 2009. These scenarios bookend the range within which annual load and peak day usage will reside should underlying indicators vary from Woods & Poole's long range estimates.

Table 3-8: Expected Total System Load Growth Across Scenarios

	Low	Mid	High
2011 - 2016	1.30%	1.48%	1.71%
2016 - 2021	1.47%	1.66%	1.82%
2021 - 2026	1.49%	1.68%	1.85%
2026 - 2031	1.28%	1.46%	1.67%
2011 - 2031	1.39%	1.57%	1.76%

Load growth under poor economic conditions is expected to be around 1.4% 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 additional load of 20 million therms while low growth will result in load 17 million therms less than predicted in the medium growth scenario.

Table 3-9: Expected Total System Load Across Scenarios

	Low	Mid	High
2011	299,438,282	301,885,823	304,992,382
2016	319,401,636	324,864,165	331,972,707
2021	343,577,530	352,669,721	363,230,566
2026	369,975,542	383,382,411	398,054,290
2031	394,334,672	412,244,157	432,407,449
Deviation	(17,909,485)		20,163,292

Uncertainties

This forecast represents Cascade's best guess about future events. There are several important factors that make prediction future load at this time particularly difficult – economic recovery, carbon legislation, building code changes, carbon legislation, direct use campaigns, soft 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, unchanged from Cascade's 2008 IRP, where chosen because of their consistency in returning statistically valid results. While they maybe the best mathematically, they are not the sole and only determinants of load. As a result, while Cascade believes that the numbers presented here are accurate, and that the scenarios presented represent the full range of possibility, there is and always will be uncertainties in predicting the future.

Section 4

Distribution System Enhancements

Forecasting by town allows Cascade to estimate the need for distribution system enhancements with a reasonable level of accuracy in the near term of the planning horizon. A localized forecast approach also allows a non-coincidental peak forecast to be developed which is necessary when estimating distribution system enhancement needs. Gas supply and pipeline transportation become secondary issues if the distribution system is constrained. An important part of the planning process is to determine potential areas of distribution system constraints, analyze possible solutions, and estimate costs for eliminating constraints.

Distribution System Modeling

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 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. This process is known as "gas distribution system modeling".

The modeling process is important because it lets the engineer determine how much flow can be delivered at various places on the distribution system. For instance, when large customers are added to a distribution network, the engineer must determine if the network capacity is large enough to provide the additional flow needed to fulfill customer requirements. Modeling is also important when planning new distribution systems. The correct size main distribution pipes must be installed to allow for the flow needed to meet the requirements of current customers, and reasonably anticipated future customers at reasonable costs.

It is desirable to know if an existing distribution system has enough capacity to satisfy new loads due to increasing numbers of customers in the future. The model can also be used to simulate increasing the gas flows through the existing pipes until the pressure loss in the pipes becomes unacceptable.

Engineering Modeling by Town

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 is determined to be a constraint area. When constraint areas are found, the analyst determines the most effective way of solving the problem. The solutions sometimes entail increasing the pressure in the system. However, in most situations where future constraint areas are identified, some amount of looping is also needed. The costs for the loops are determined based on system wide averages of past system reinforcements and extensions projects. The average cost per foot is established for each area, and then the most cost-effective alternative to solving the pressure problem is found. After these costs are tabulated, potential reductions of demand within constraint areas due to conservation will be included in the analysis to determine whether any of the costs can be avoided or delayed.

The modeling output is compared to and, where appropriate, supplemented with data from local field personnel to provide forecasts by town. This allows the analyst to specifically determine, town by town, what reinforcement would be necessary to each system for each year. These town by town costs are then grouped together by gate station.

Key Findings

The results of the distribution system analysis are shown in Table 4-1. The table shows the estimated costs of distribution system enhancements necessary to eliminate constraint areas over the 20 year planning horizon. Appendix C contains further information regarding the possible solutions to alleviate the distribution system constraints. It should be noted that the proposed solutions are preliminary estimates of reinforcement solutions and actual solutions may be different due to differences in actual growth patterns and/ or construction conditions from those assumed in the initial modeling.

These results were based on the best information available and included both the anticipated load growth for the core market from the medium demand forecast along with the contracted peak delivery for each of the non-core customers.

Equally important is to review the impacts of proposed conservation resources on anticipated distribution constraints. 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 will be discussed in Section 5, 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, (the 2011 through 2025 timeframe) the opportunity for targeted conservation programs to provide a cumulative benefit that offsets potential constraint areas may be an effective strategy.

Table 4-1
Yearly Reinforcement Costs by Gate

Gate	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Arlington						$875			$15,660		
Bellingham I			$40,000				$349,192				
Bend			$1,053,775		$2,671,000		$1,699,000		$1,057,000	$710,200	
E Stanwood				$82,954							
Hermiston	$90,480				$61,553	$30,450				$5,425	
Kennewick	$1,564,500		$128,325	$40,238	$872,356			$56,115	$81,128		
Lynden			$22,403			$164,002		$79,388			
Madras						$1,229,080					
Mount Vernon											
Pasco	$145,730	$373,293				$62,776		$113,782			
Pendleton	$28,493										
Prineville			$117,705			$39,235					
Redmond		$75,668	$46,328		$134,438				$81,833	$113,782	
Sedro Woolley	$81,345			$218,595		$875		$35,888	$224,727		
Shelton	$7,788	$4,225,000	$705,589	$251,309		$1,590,000				$1,140,718	
Stanwood				$35,018		$51,983		$106,773			
Sumas Boarder	$298,493			$97,440			$149,640			$77,574	
Sunriver	$306,050					$43,718					
Umatilla							$210,800				
Walla Walla					$63,240						
Yakima		$112,100						$1,915,000			
Grand Total	$2,522,877	$4,786,061	$2,114,124	$725,553	$3,802,587	$3,212,993	$2,408,632	$2,306,944	$1,460,347	$2,047,699	$0

Gate	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Grand Total
Arlington		$116,024									$132,559
Bellingham I			$34,800				$149,616				$573,608
Bend		$128,915		$29,145			$67,260		$43,283		$7,459,578
E Stanwood											$82,954
Hermiston											$187,908
Kennewick			$2,600,000			$203,535			$43,065		$5,589,261
Lynden						$81,000			$41,978	$60,465	$449,235
Madras											$1,229,080
Mount Vernon			$20,880					$56,333			$77,213
Pasco											$695,581
Pendleton											$28,493
Prineville											$156,940
Redmond								$35,872	$208,640		$696,560
Sedro Woolley		$256,709			$29,146			$12,180	$50,925		$910,389
Shelton			$229,068	$5,575,000							$13,724,471
Stanwood	$174,876		$40,000								$408,649
Sumas Boarder		$170,000		$295,944			$1,072,139		$119,625	$250,000	$2,530,856
Sunriver											$349,767
Umatilla											$210,800
Walla Walla											$63,240
Yakima											$2,027,100
Grand Total	$174,876	$671,648	$2,924,748	$5,900,089	$29,146	$284,535	$1,289,015	$104,385	$507,515	$310,465	$37,584,238

Section 5

Supply Side Resources

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 the lowest costs possible while providing an infrastructure that responds to the customers' concerns in meeting customer growth and provides all necessary administrative services to provide the stated services. Assuming such an infrastructure is in place and 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 components that constitute the "bundled services" required by core market customers.

Cascade's 20-year supply side resource goal is to continue to meet the energy needs of its core market customers with 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.

This section describes the various gas supply resource and transportation resource options that are available to the Company as supply side resources.

Gas Supply Resource Options

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 meet the needs of the broad seasonal peak and the needle peaks of the heating season in order to provide economical service to low load factor customers.

Firm Supply Contracts

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except for *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 the obligation to serve and the lack of easily obtainable alternatives for consumers during periods of peak demand. Firm contracts can provide baseload services, provide seasonal peaking services during the winter months, or can be used to meet daily needle peaking requirements. Each of these services is discussed briefly below.

Baseload resources are those that are taken day in and day out, 365 days a year. As a result, baseload 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. Cascade’s ability to contract for baseload supplies is limited because of the relatively low summer demand on the system. Baseload 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 3 to 5 month durations (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 baseload supplies will be 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 producer must deliver the gas when the Company requires it, but the Company is not required to take gas unless needed to meet customer load requirements. Peaking resources typically allow the Company to take between 15 and 20 days of service during the winter period. These resources are more expensive than baseload or winter supplies and typically include fixed charges to cover the costs for the producers 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 industrial customer base. These customers would be required to maintain standby or alternate fuel capability that Cascade would contract the right to request the customer switch to so Cascade could utilize (divert) their gas supply and transportation capacity to meet the Company’s core 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.

Contract terms for firm commodity supplies vary greatly. Some contracts specify fixed prices, while others are based on indexes 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.

Appendix E summarizes the gas supply alternatives evaluated during this planning cycle.

Spot Market Supplies

Gas that is purchased for a short period of time (1 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 are provided from gas supplies not under any long- term firm contract, as mentioned above. 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. [1]

Due to the potential for interruption of the spot market, these supplies are not considered as reliable a 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. These available volumes are likely to vary daily, depending on production or the suppliers' ability to store un-marketed supply. Under a NAESB (North American Energy Standards Board) contract, which is the standard contract used by buyers and sellers when entering into short term supply transactions, parties have the ability to identify firm variable or interruptible quantities for these supplies. Therefore, these spot volumes are more susceptible to daily operational constraints on the upstream pipelines. This is particularly true in the case of Northwest Pipeline, which is a displacement pipeline with bi-directional flow. Depending on how gas is scheduled versus actually flowing between compressor stations, constraints can possibly occur. Complicating matters is that 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 contract may allow the flexibility to reduce takes in order to take advantage of 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 weather moderation.

Other Unconventional Gas Supply Resources

Cascade considers Unconventional Gas Supply Resources such as supplies from an LNG Import Terminal, BNG or other manufactured gas supply opportunities as speculative supply side resources at this point in time. In most cases unconventional gas supply resources would become an alternative to traditional gas supplies from the conventional gas fields in Canada or the Rockies and would have to compete for inclusion in the Company's portfolio planning. The two remaining LNG Import Terminal projects since the publishing of the last IRP, Jordan Cove and Oregon LNG, appear to shifting to export facilities. In early 2012, both facilities filed with FERC to withdraw their plans to import LNG. Jordan Cove refiled with FERC to become an exporter; industry experts expect Oregon LNG to follow suit.

One of the potential impacts of having export facilities in the Pacific Northwest (including the Kitimat) is what affect the flow of natural gas to export facilities will have on competition and pricing of natural gas supplies. Demand for natural gas in Asia, coupled with relatively inexpensive and plentiful shale gas may create a favorable long-term market opportunity for North American producers. For example, Japan has been hesitant to restart their nuclear plants in the aftermath of the devastating earthquake and tsunami of 2011. However, demand for energy will continue there as well as in China, as that country increasingly flexes its growing economic muscle and need for energy to drive its manufacturing base.

Infrastructure such as the Pacific Connector Pipeline to move natural gas to these facilities also means the opportunity to divert some of these supplies to markets such as LDCs that are located near the routes to the export facilities. In periods of great demand in Asia one would expect upward pressure on natural gas prices; correspondingly during periods of lower demand, prices would likely drop. Of course, if it is economical to do so, producers will increase the volumes of natural gas to this area, which will provide another supply resource alternative for Cascade. While it is much too early to tell (since exports have yet to begin at any of these facilities), export facilities in the Pacific Northwest could potentially create a new pricing dynamic for the region; a dynamic which Cascade will be monitoring carefully as both public (EIA) and private (Wood MacKenzie, Bentek) intelligence becomes available.

Palomar Gas Transmission has withdrawn its application for a certificate to build a natural gas pipeline in Oregon, and it has told the Federal Energy Regulatory Commission that it continues to work with potential customers and a potential additional partner to provide a regional solution to the need for access to this important form of energy. Palomar said that while they will no longer seek to permit a pipeline to serve the previously proposed liquefied natural gas terminal on the Columbia River, it will continue its effort to find commercial support for a new pipeline in Oregon to meet the needs of the Pacific Northwest.

Another alternative is BNG. Bio natural gas continues to receive increased attention as a possible resource. BNG typically refers to a 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 other 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. BNG can be used as a low-cost fuel in any country for any heating purpose, such as cooking. 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.

In many cases, there is currently not enough pricing and information available to be considered in this planning cycle; however, where possible, we have endeavored to analyze those situations where we feel sufficient data is available. Cascade continues to monitor the BNG activities of companies such as Pacific Gas & Electric, Intermountain Gas, Sempra Utilities and Puget Sound Energy.

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, therefore 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. 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 pipeline transportation and may limit the flexibility of the resource. Cascade does not own its own storage facility and therefore must contract with storage owners to access a portion of their storage capacity. In 1994, Cascade had two contracts for utilization of underground storage located at Jackson Prairie (SGS-1). SGS-1 service is contracted directly from NWP and additional SGS-1 service was assigned from Avista Corporation for Cascade's use. Both of these contracts provided daily deliverability and seasonal inventory capacity. However, Avista declined to extend its agreement with

Cascade and the Avista storage service was no longer available following the 2006/07 heating season.

Consequently, Cascade entered into an Agreement with Northwest Pipeline for additional Jackson Prairie storage service that will replace the access to storage that was available through the Avista storage contract. The new Agreement will provide Cascade with twice the amount of daily deliverability of the Avista agreement (30,000 Dth/d vs. 15,000 Dth/d) with approximately the same annual storage quantity. The Jackson Prairie expansion will be fully operational by Fall 2012. Cascade has also entered into a companion transportation Agreement with Northwest Pipeline for the transportation of gas supplies stored under this Agreement to Cascade's service area. The Company also has contracted for service (LS-1) from NWP's Plymouth, Washington LNG facility. 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. The Company's contracted storage services are summarized below.

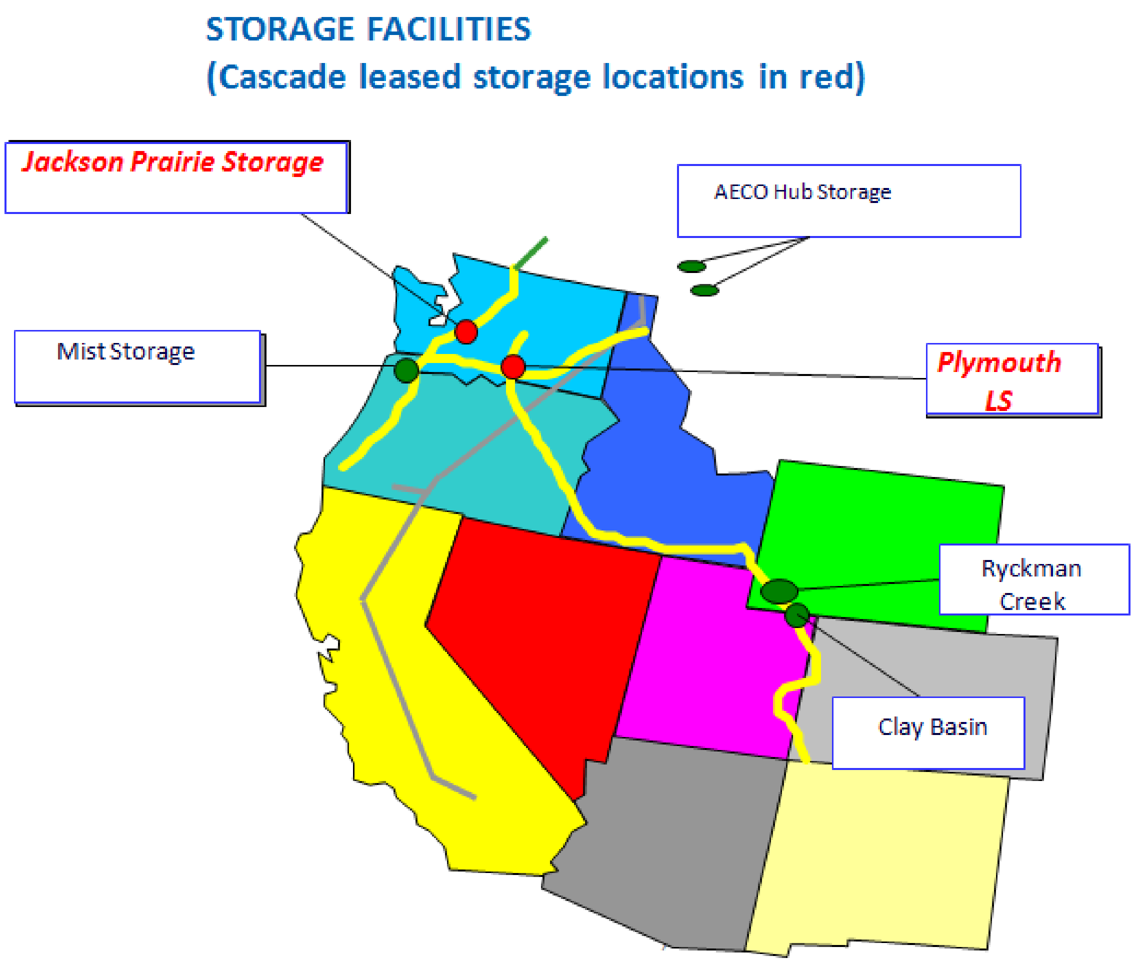
TABLE 5-1
Cascade's currently contracted storage services

STORAGE FACILITY	SEASONAL QUANTITY (Dths)	DAILY WITHDRAWAL RIGHTS (Dths)	EXPIRATION DATE
PLYMOUTH (LNG)	562,200	60,000	10/21/2019
JACKSON PRAIRIE	604,351	16,789	10/31/2019
JACKSON PRAIRIE EXPANSION	326,339	30,000	10/31/2060

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 SGS-1 and LS-1 service requires TF-2 firm transportation service for storage withdrawals, and Cascade has sufficient firm TF-2 service to meet its storage daily deliverability levels.

Figure 5-A provides a map of the various storage discussed above, as well as the location of other storage facilities in the region.

FIGURE 5-A



Capacity Resource Options

Capacity options are either interstate pipeline transportation resources or capacity on Cascade's local distribution system. Cascade's local distribution system was 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. Cascade generally has the distribution capacity available to deliver the gas to customers if the pipeline delivers the gas to the Company's citygate stations. Core interruptible service relates to the spot market supplies and interruptible interstate pipeline transportation contracted to serve these markets. Cascade does not contract for firm supply or interstate transportation for these interruptible customers. Cascade's interruptible rates also reflect the fact that no firm supply or transportation services are purchased on behalf of interruptible customers.

Interstate Pipeline Transportation Services

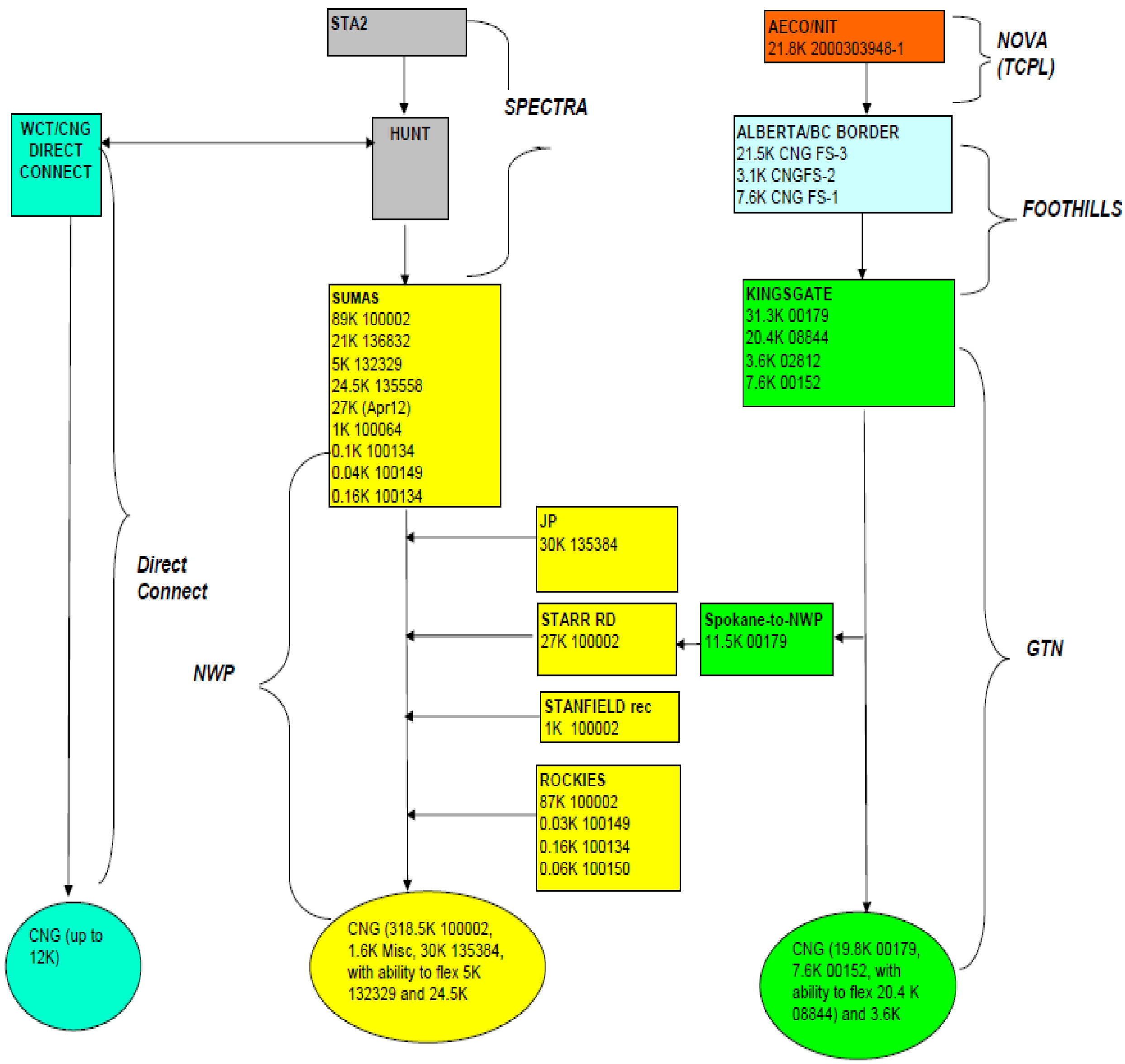
Pipeline transportation resources are utilized to transport the gas supplies from the producer/supply sources to Cascade's system. Cascade currently purchases supplies from three different regions or basins: U.S. Rockies, British Columbia, and Alberta, Canada. Unless the gas supplies have been "bundled" by the supplier, these resources require pipeline transportation to deliver them to Cascade's local distribution system.

Cascade has several long-term annual contracts with NWP, one long-term annual contract and three long-term winter-only contracts with GTN (including the upstream capacity on Trans Canada Pipeline’s Foothills and Alberta systems), and one long-term annual contract with Spectra in British Columbia, Canada. These contracts do not include storage or other peaking services that provide additional delivery capability rights ranging from 9 to 120 days.

As noted earlier, available capacity exists on two of the three upstream pipelines serving the region: Spectra Energy’s T-South Mainline from Northeast BC to the BC-Washington Border at Sumas, and TransCanada’s GTN System that takes natural gas from Alberta at Kingsgate, Idaho and ships it to and through the region. The Company constantly reviews existing capacity options and works to negotiate contract terms that make sense for both parties, whenever we determine a project is viable.

Figure 5-B provides a schematic of Cascade’s various transportation agreements, approximate contract demand (in thousands of dths) and their general flow patterns.

FIGURE 5-B



Proposed and New Pipelines

Additionally, several pipeline projects have been proposed by a variety of developers to serve the region. As noted below, some of these projects, which were part of the last IRP, are no longer active, but are recapped and updated with new information since the last IRP.

- Blue Bridge Pipeline – Williams Gas Pipeline Company and Puget Sound Energy proposed this project which included the installation of additional compression horsepower at existing Northwest Pipeline stations and the construction of up to 172 miles of 30-inch pipeline and 16 miles of 36-inch pipeline. The project was designed to deliver about 500 MMcf/d from Stanfield, Oregon to the I-5 Corridor and generally follow Northwest Pipeline's existing pipeline corridor for the majority of the route. On September 1, 2010 the partners announced that they had filed with FERC to shelve the project.

- Palomar Pipeline – Palomar Gas Transmission is a partnership between NW Natural and TransCanada. The proposed 212 mile, 36-inch-diameter underground pipeline will extend from TransCanada's GTN system near Madras, Oregon to NW Natural's system near Molalla, Oregon. It will be a bi-directional pipeline with an initial capacity of 1,200 MMcf/d. As noted earlier, Palomar Gas Transmission has withdrawn its application for a certificate to build a natural gas pipeline in Oregon.

- Integrated Blue Bridge/Palomar project – Essentially would create an "Oregon Hub" via a Transportation by Other (TBO) process using vintage NWP capacity across the Columbia Gorge combined with vintage GTN capacity from Stanfield to Madras, then using Palomar capacity from Madras to Molalla tied to NWP expansion capacity up the I-5 Corridor in Washington. The in-service date was projected to be 2016. This project was presented at an extraordinary joint meeting of the Washington and Oregon utility commissions in February 2011.

- Pacific Connector Gas Pipeline Project – as identified earlier, is a proposed 234-mile, 36-inch diameter pipeline designed to transport up to 1 billion cubic feet of natural gas per day from the Jordan Cove LNG terminal to markets in the region. The Pacific Connector project includes interconnects to Williams´ Northwest Pipeline near Myrtle Creek, Oregon; Avista Corporation´s distribution system near Shady Cove, Oregon; Pacific Gas and Electric Company´s gas transmission system; Tuscarora Gas Transmission´s system; and Gas Transmission Northwest´s system, all located near Malin, Oregon. As noted earlier, this project is now viewed as an export facility; but it also has the possibility of bringing additional supply to the area to make part of our resource portfolio.

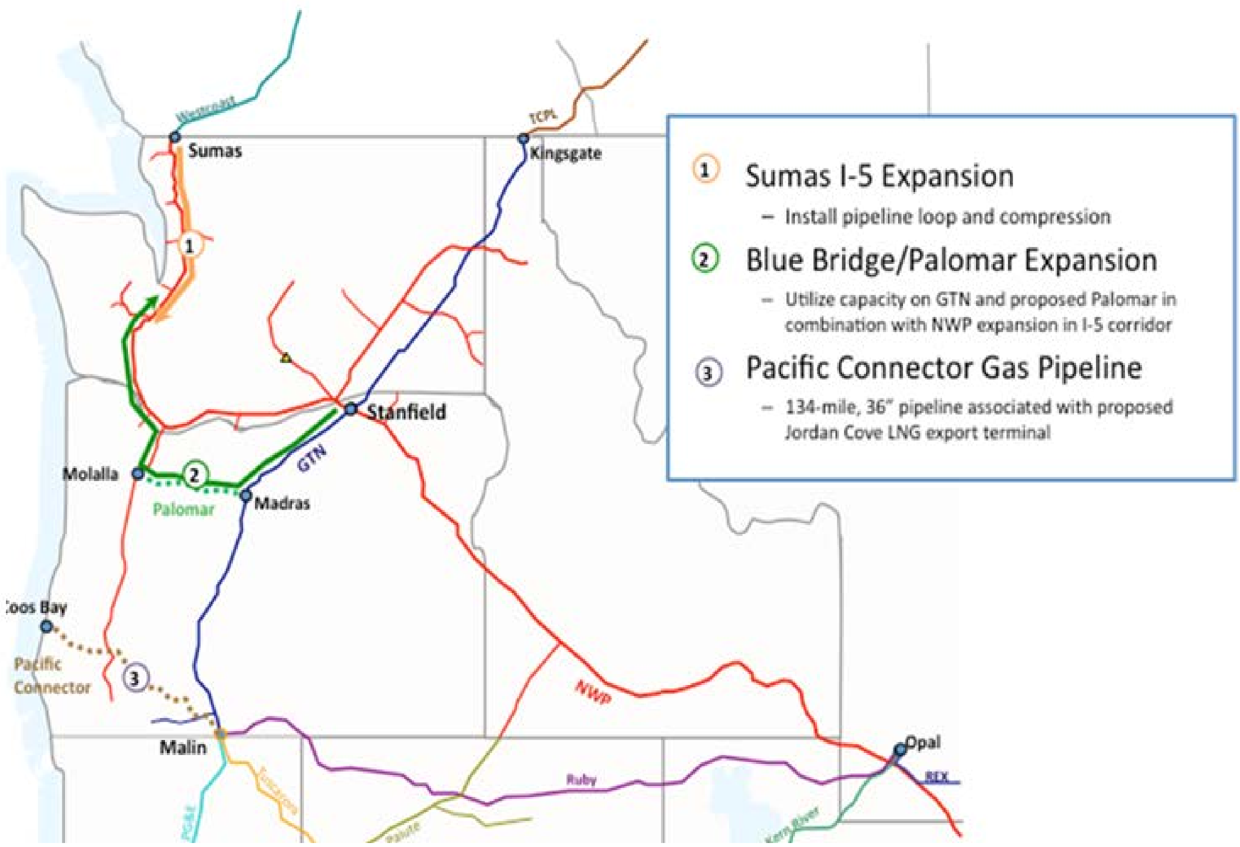
- Southern Crossing Pipeline Extension – this is a project development that is being developed by Terasen Gas. It will extend the existing Southern Crossing from Oliver BC to Kingsvale BC. This bi-directional pipeline would flow new production from Northern BC east to GTN or move Alberta gas into the I-5 corridor via Spectra Pipeline.

On July 28, 2011, El Paso Corporation placed the Ruby Pipeline in service. Ruby is a 680-mile, 42-inch interstate natural gas pipeline, providing transportation service from Opal, Wyoming, to interconnections near Malin, Oregon. Ruby has an initial design capacity of up to 1.5 billion cubic feet per day (Bcf/d) and traverses portions of four states:

Wyoming, Utah, Nevada, and Oregon. The project utilizes four compressor stations: one near the Opal Hub in southwestern Wyoming; one south of Curlew Junction, Utah; one at the mid-point of the project, north of Elko, Nevada; and one in northwestern Nevada.

Cascade's utilization of pipeline transportation and peak day capacity for core and contracted for non-core firm transportation gradually changes over the planning horizon. Current company-acquired firm supplies utilize existing core firm transportation capacity. Future core market growth utilizes non-core firm transportation capacity that will be converted to core market firm transportation capacity as core market growth occurs. Figure 5-C provides a map of the current existing and various pipeline projects discussed above.

FIGURE 5-C



Transportation resources historically have been purchased from the pipeline at the time of an expansion under long-term (twenty to thirty year) contracts. As a result, the Company may find that it has capacity excess to its core market needs, especially in the early years following an expansion. Since late 1989, Cascade has, through its Optional Firm Pipeline Capacity tariffs, allowed its non-core customers to utilize Cascade's firm pipeline capacity that is excess to current core customer requirements. By accepting all of the obligations associated with the underutilized pipeline capacity, the non-core customers have relieved Cascade's core customers of the costs associated with holding the pipeline capacity for future growth.

Additionally, pipeline capacity is a tradable commodity through the Electronic Bulletin Board (EBB). Should a utility have temporarily underutilized transportation capacity it can release that capacity to third parties. Such activities allow holders of pipeline capacity contracts to recoup a portion of the fixed costs incurred. The value of the capacity will fluctuate depending upon market conditions. Any pipeline capacity in excess of core requirements can be offered to qualified buyers. The capacity is offered to any credit-worthy market through the respective pipeline's EBB.

As Cascade's customer count and loads continue to grow, the Company will need to acquire additional capacity resources. In May 2011, Cascade was able to obtain vintage NWP capacity through a pre-arranged agreement with the Pipeline that will provide additional MDDOs (daily delivery) to several gates, including Yakima/Union Gap on the Wenatchee lateral and Bellingham/ (Ferndale) gates. This capacity (27,063 dths) becomes available to Cascade in April 2012. The current vintage transportation rates on NWP compared favorably to any of the other proposed pipeline projects at the time, such as the Blue Bridge/Palomar integrated project. For the past several Integrated Resource Plans, Cascade has identified the need for incremental pipeline capacity in order to meet anticipated peak day requirements for its core market as early as the 2012/2013 timeframe. Additionally, there are several locations where Cascade's design day requirements are greater than existing contracted delivery, including the Bellingham area. With the incremental capacity Cascade will have enough receipt MDQ to meet core requirements until 2023 and will provide adequate delivery MDDOs until the 2022 timeframe. The table below describes the capacity:

TABLE 5-2

NWP Incremental Vintage Capacity, effective 4/1/2012

Receipt Point	Delivery Pt	Del Pt Qty (Dths)
Sumas	Bellingham	8,074
Sumas	Prosser	29
Sumas	Yakima/Union Gap	310
Sumas	Umatilla	6,160
Sumas	Plymouth LNG	12,490

In December 2011, the Company was presented with an opportunity to obtain vintage NWP capacity through a pre-arranged agreement with Northwest Pipeline that will provide additional MDDOs (daily delivery) to Sedro-Woolley, and by extension increase our firm rights in NWP Zone 30 (Cascade Zone 30-S and 30-W).

TABLE 5-3

NWP Incremental Vintage Capacity, Sedro-Woolley block

REC PT	*DEL PT*	*Dths/DAY*	*DTHS/D AND TERM*
SUMAS	SEDRO	6191	03/2012 – 10/2050
SUMAS	SEDRO	1050	04/2013 – 10/2050
SUMAS	SEDRO	3259	01/2014 – 10/2050

The pre-arranged agreement was subject to competitive bid and it was ultimately awarded based on the offer which represented the highest net present value (NPV). We believed that based on our modeling, economic feasibility of vintage vs. incremental capacity costs, proximity to our distribution system and our ongoing obligation to serve, that proposing a long-term contract through October 2050 would ensure that the agreement would be awarded to Cascade.

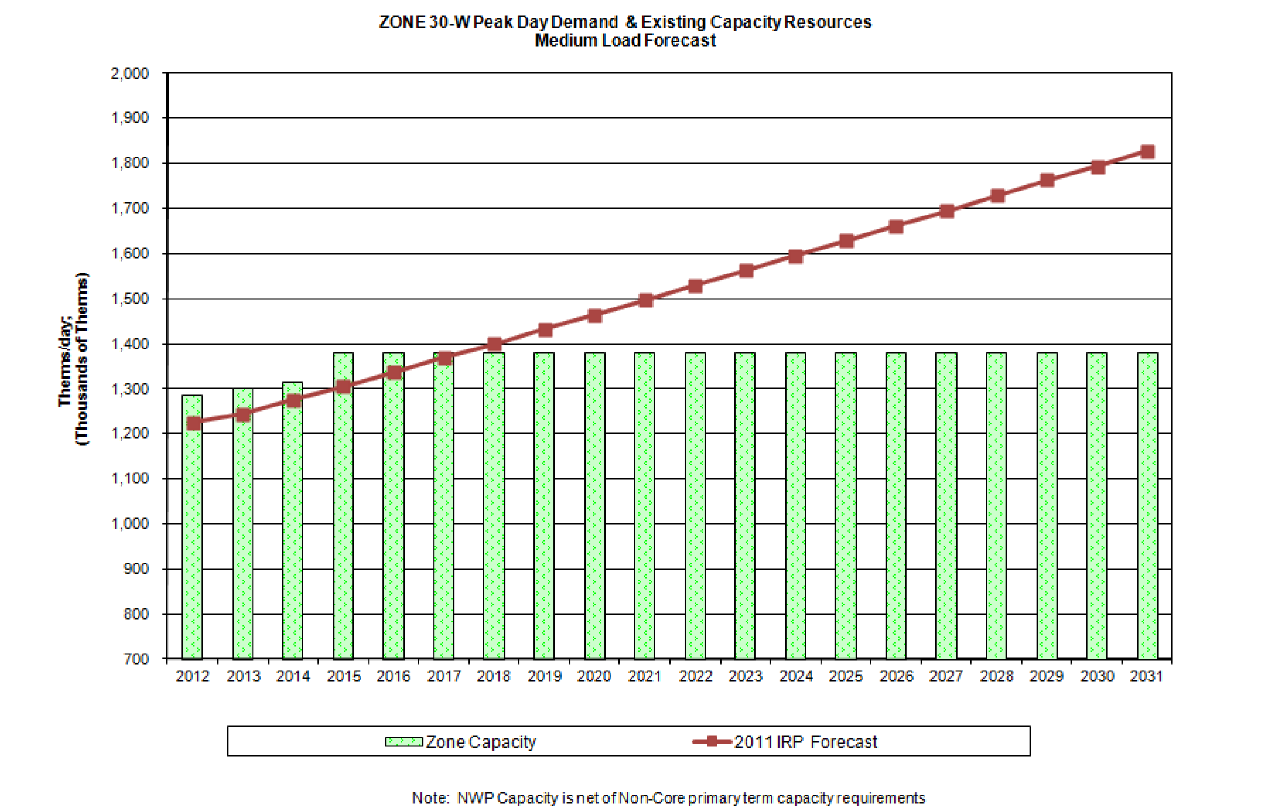
SUPPLMENTAL BACKGROUND AND ANALYSIS

- For the past several Integrated Resource Plans requirements are greater than existing contracted delivery in CNG Zone 30-W, particularly the Bellingham area. Cascade has identified the need for incremental pipeline capacity in order to meet anticipated peak day requirements for its core market in Whatcom County (CNG Zone 30-W) as early as the 2018 timeframe. Figure 5-C-1 provides a clear picture of the impending peak day shortfall.
- Even at maximum rate, vintage capacity is considerably less expensive than proposed pipeline expansion projects including a Palomar/Blue Bridge type of scenario, which is anticipated to be upward of $.82/dkth and is not guaranteed to be built.
- Both TransAlta and Boardman coal-fired generation plants have committed to reduce and eventually cease operation and will likely be replaced with gas fired generation, providing greater interest in the capacity, particularly if Puget determines to add to their gas fired generation in the areas to meet power shortfalls identified in their integrated resource plan.
- The proposed capacity package provides delivery to Sedro-Woolley, a point on CNG's system.
- Although this capacity will become effective prior to the actual need, NWP has not identified any plans for a future system expansion in the area; however, having this capacity would lessen the amount of incremental capacity (and

associated costs) Cascade would need to pay for to participate in a future system expansion.

- Acquiring the proposed capacity from NWP will extend our ability to meet peak day in CNG Zone 30-W to around the 2022 time frame. The combined Zone 30-S and Zone 30-W (the actual nominated zone) would have sufficient capacity to meet peak day through 2026.

FIGURE 5-C-1



<u>Ruby Pipeline and Incremental GTN northbound firm service.</u>

Throughout 2011, Cascade worked with both existing Ruby shippers and with Ruby Pipeline to obtain discounted, long-term firm capacity on Ruby Pipeline along with the chance to acquire firm Malin north capacity on GTN through a pre-arranged agreement via Ruby that will provide the means to deliver Rockies supplies to Central Oregon, thereby increasing supply diversity and mitigating some of the negative impacts of constraints on Northwest Pipeline. Currently, gas supplies for Central Oregon are almost exclusively sourced from Alberta. While this has been a price advantage we feel it is important to have flexibility of supply options, particularly since we may find ourselves competing for Canadian supplies that will be pulled to the export facility in Kitimat to serve increasing Asian demand.

Ultimately, as will be explained further, Cascade worked with Ruby to finalize a long term transportation agreement based on the following proposal:

- **Term:** The term of the proposed Ruby Pipeline capacity is for 25 years, beginning as early as April 1, 2012 but no later than November 1, 2012.

- **Maximum Daily Quantity (MDQ):** November 1st - April 30th of each year: 10,000 dths/day. Ruby would also provide Cascade with an option for 20,000 Dth per day (in addition to the 10,000 Dth described above) pursuant to the same terms and conditions. The option would expire on October 31, 2014. If at any time during the option period, Ruby receives a bona fide offer from a third party to contract for the optioned capacity, Ruby would provide notice to Cascade with sixty days to exercise the option. This will be contractually structured consistent with FERC allowances.

- **Receipt Point(s):** Any Ruby interconnect at the Opal Hub, including (CIG, Overthrust, Pioneer)

- **Delivery Point:** Ruby – GTN interconnect at Malin, Oregon (Turquoise Flats)

- **Rate:** Fixed reservation rate of $ 0.75 per dth/d for the twenty-five year term, plus Ruby commodity and FERC fuel and variable charges as authorized (estimated at $0.01 and 1.5% respectively). The current recourse rate is $0.95 per dth/d. This proposal represents a 21% discount.

- **GTN Capacity:** Separate from the Cascade/Ruby capacity, Ruby has been working with GTN to contract for maximum rate firm transportation rate on GTN and compensating GTN for its capital expenditures in providing firm, northbound service. Ruby would, in turn, post on GTN's EBB a pre-arranged capacity release to Cascade with Malin northbound firm transportation capacity, subject to bid, consistent with FERC rules.

SUPPLEMENTAL BACKGROUND AND ANALYSIS

As the chart below indicates, the annual cost per unit for the Nov-Mar Ruby capacity would be less than vintage year round capacity on Northwest Pipeline. Granted, Northwest Pipeline does have some capacity release value but there is intrinsic value with Ruby capacity associated with providing supply diversity for Central Oregon, plus the Ruby/GTN path will give us an alternative path for re-directing NWP Rockies gas around a Kemmerer constraint. Rockies gas originally destined for NWP could be shipped via Ruby-GTN to Stanfield where it can then flow back on NWP if needed, potentially avoiding having to sell otherwise constrained supplies at less than purchase contract terms or incur banking or penalty charges.

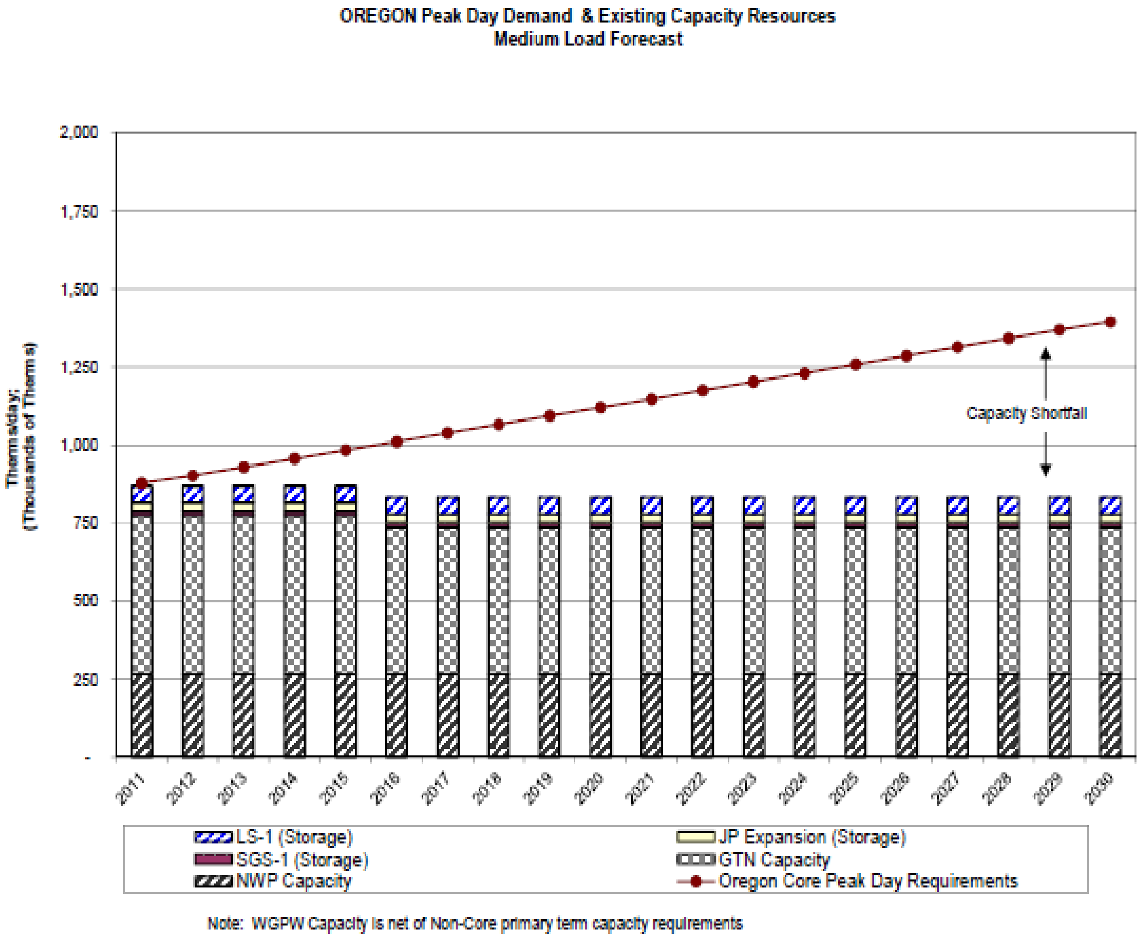
TABLE 5-4
Ruby vs Vintage NWP annualized capacity costs

Category	Rate, per dth	Days in Year	Annual Cost
Vintage NWP	$ 0.3879	365	$ 141.58
Discounted Annual Ruby	$ 0.7600	365	$ 277.40
Winter Only (Nov-Apr)	$ 0.7600	181	$ 137.56

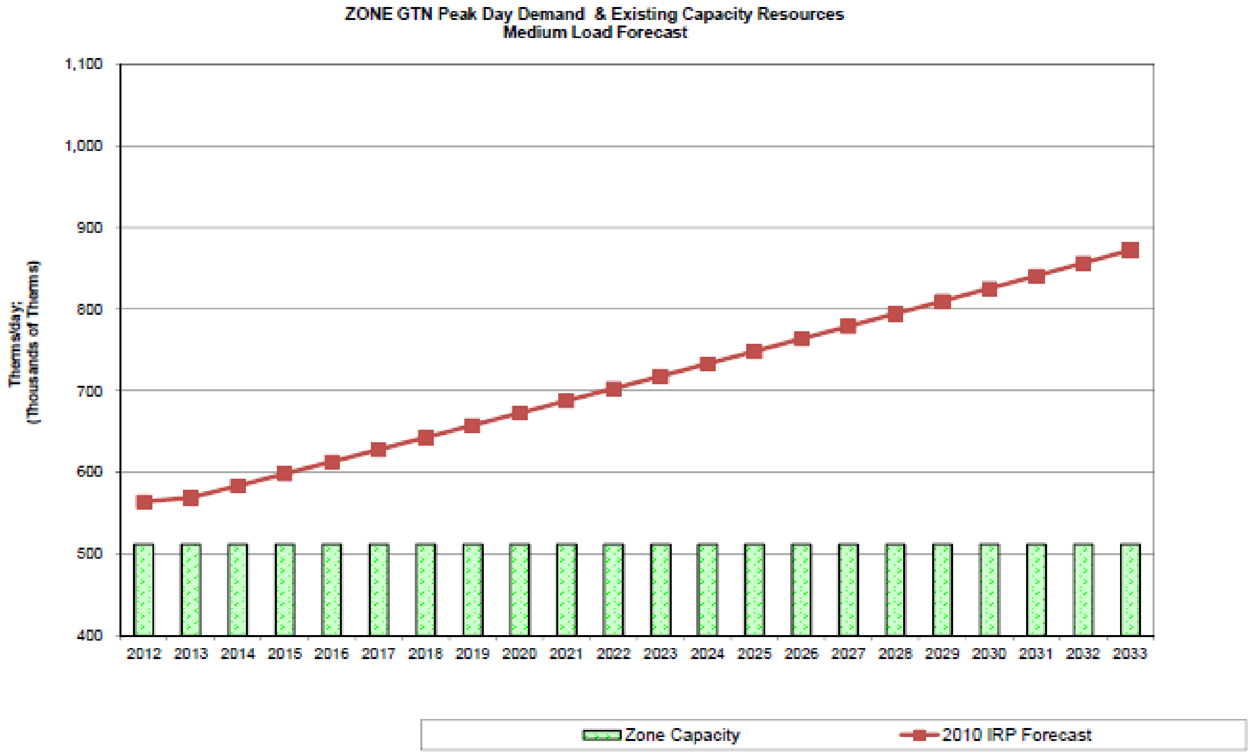
The proposed Blue Bridge and Palomar pipelines which would also bring Rockies gas to the Pacific Northwest are currently on hold and do not look likely to be built. In addition, these options have projected rates that exceed $0.80/dth.

As indicated earlier there was also the possibility of acquiring multi-year (up to ten) capacity releases from existing Ruby shippers; however, none of the parties we worked with were able to match the discount being proposed by Ruby. In fact, most of the parties we spoke with initially did not offer a discount; and when they did the discounts were typically 10%. Additionally, none of these parties had or were seeking to obtain firm primary northbound service on GTN. From the Company's perspective under current resource planning guidelines we could only use the current GTN backhaul as a secondary service; it couldn't be used for peak day planning in the IRP. However, if Ruby is successful in acquiring the GTN northbound capacity and we acquire it via GTN's EBB, then the Ruby/GTN capacity would form a needed primary firm resource for regular use as well as for peak day.

As the following chart shows, Oregon faces sizeable capacity shortfalls on peak day in the long-term. Short-term, we have been and plan on continuing to meet these needs via citygate supplies, which do not require Cascade to pick up additional capacity. Additionally, since GTN is still experiencing continued de-contracting, it is likely that there will be available capacity available on GTN for short term capacity releases. While this is fine for the short-term, we will need to consider acquiring additional resources to meet peak day. The portions of Oregon served by NWP (Zone 24 and Zone ME-OR) have sufficient long-term capacity through 2026.



However, as can be seen on the following chart, the GTN zone, which is primarily supported by Alberta sourced supplies, is significantly short. Therefore, not only will acquiring Ruby bring supply diversity to supplement what is purchased from Alberta, having Ruby acquire firm northbound GTN capacity and releasing it to Cascade will help us meet our long-term incremental need for capacity. It should also be noted that our modeling and discussions with stakeholders have recognized that Cascade needs more storage to serve Oregon. One possible source of storage Cascade will consider as a result of having Ruby capacity is Ryckman Creek storage at the Opal Hub, which will connect to Ruby, thereby giving Cascade a possible storage source to meet Oregon load, as well as price arbitrage to the benefit of all ratepayers.



See Section 7, Resource Integration for additional information regarding the SENDOUT™ modeling for Ruby Pipeline and Incremental GTN northbound firm service.

Some of the growth will require Cascade to look at alternatives to pipeline mainline capacity such as LNG satellite facilities located near or within the Company's distribution system. The Company is continuing to study the viability of LNG satellite facilities to meet these needs.

The Wenatchee lateral is an example where an LNG satellite facility may be more cost effective than the traditional solution of pipeline expansion for solving the upcoming capacity constraints on the lateral. Preliminary cost studies indicate that an LNG satellite facility solution may be 1/3 to 1/2 the cost of a pipeline expansion project that would provide the same peak day incremental capacity.

Additionally, the historic load growth the Company enjoyed throughout much of its service areas has begun to create the need to increase the physical capabilities of some of the pipeline's citygates. Even though Cascade may have an adequate amount of pipeline capacity available on the pipe, it may not have the contractual or physical capabilities at the citygate to meet the incremental load requirements. LNG satellite facilities or trucked in LNG re-gasification facilities or other similar type solutions may provide lower cost alternatives to the cost of city gate rebuilding projects. The Company will continue to study the viability of these alternatives.
Appendix E provides a summary of current and potential capacity resources evaluated during this planning cycle.

Natural Gas Price Forecast

For IRP planning 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 has considered price forecasts from several sources, such as Wood Mackenzie, Energy Information Administration, the Financial Forecast Center's forecast, as well as our observations of the market to develop the low, base and high price forecast. The following discussion provides an overview of the development of the baseline forecasts.

Development of Baseline Henry Hub price forecast

Cascade's long term planning 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. While not a guarantee of where the market will ultimately finish, the current market (NYMEX) is the most current information available that provides some direction as to future market prices. On a daily basis, we can see where Henry Hub is trading and how the future basis differential in our physical supply receiving areas (Sumas, AECO, Rockies) is trading.

The fundamental forecasts include Wood Mackenzie, Energy Information Administration (EIA), Northwest Power Planning Council, the Texas Comptroller and the Financial Forecast Center's long term price forecasts. Wood MacKenzie publishes a long-term price forecast each quarter to subscribing customers. This forecast is broken down by month through the planning horizon and includes Henry Hub as well as basis differentials for our receiving areas. The company 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 by year. Many of the other sources above also only provide price forecasts by year. Given Cascade's load profile and the need for more winter gas than summer, the company develops 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 for the above sources, the company assigns a weight to each source to develop the monthly Henry Hub price forecast for the 20 year planning horizon. The forecast weighting factors are shown in Table 5-2. At the time the price forecast was developed, the Financial Forecast Center forecast was significantly lower than the Wood Mackenzie forecast and the forward market. Given the significantly higher future prices at the time versus the Comptroller forecast in addition to the fact that it only gives a three year forecast (2012-2014), the Company decided to severely limit the Financial Forecast Center from the weighted average. The Financial Forecast Center is unlikely to be a price source for Cascade in future plans. In recent years the EIA forecast has often been lower than the actual monthly price; however it is still a respected industry barometer of prices. Therefore, the EIA forecast was given a higher weight. As discussed earlier, while current market pricing may not accurately estimate the final market price, it often is a reliable indicator. Therefore, the company gave the current market pricing (NYMEX HH) some weight based on nearness to term. It should be noted that most of the forecast providers did not provide price forecasts for 2031. We chose to blend the Texas Comptroller and the EIA. While this represented a significant increase in weight for the Comptroller (moving from 1.5% to 45% weight) we decided to use the Comptroller given that 2031 is farthest year for the price forecast and desire to use more than one source for price forecasting. We had the option of also extending the trend-line of the NYMEX HH beyond year 2022, but felt it important to recognize that NYMEX HH is more a factor in short rather than long-term price. In future plans will not use the NYMEX HH trend-line for years beyond NYMEX trading period, consistent with how all other tools are used to develop the 20 year price forecast.

Development of the Basis Differential for Sumas, AECO and Rockies

Since the company's physical supply receiving areas (Sumas, AECO, and Rockies) are at a discount to Henry Hub, we utilize the basis differential from Wood Mackenzie's most recent update and compare that to the future markets basis trading as reported in public market. Although it is impossible to accurately estimate the future, for trading purposes, the most recent period has been the best indicator of the direction of the market. Correspondingly, we applied a weighted average to determine the individual basis differential in the price forecast. Typically, we give the most weight to the current NYMEX Henry Hub price in the early years. As our forecast moves ahead we start to reduce the impact of the NYMEX (and the impact of speculation and other market uncertainties) and give greater weight to NWPPC, Wood Mackenzie and EIA.

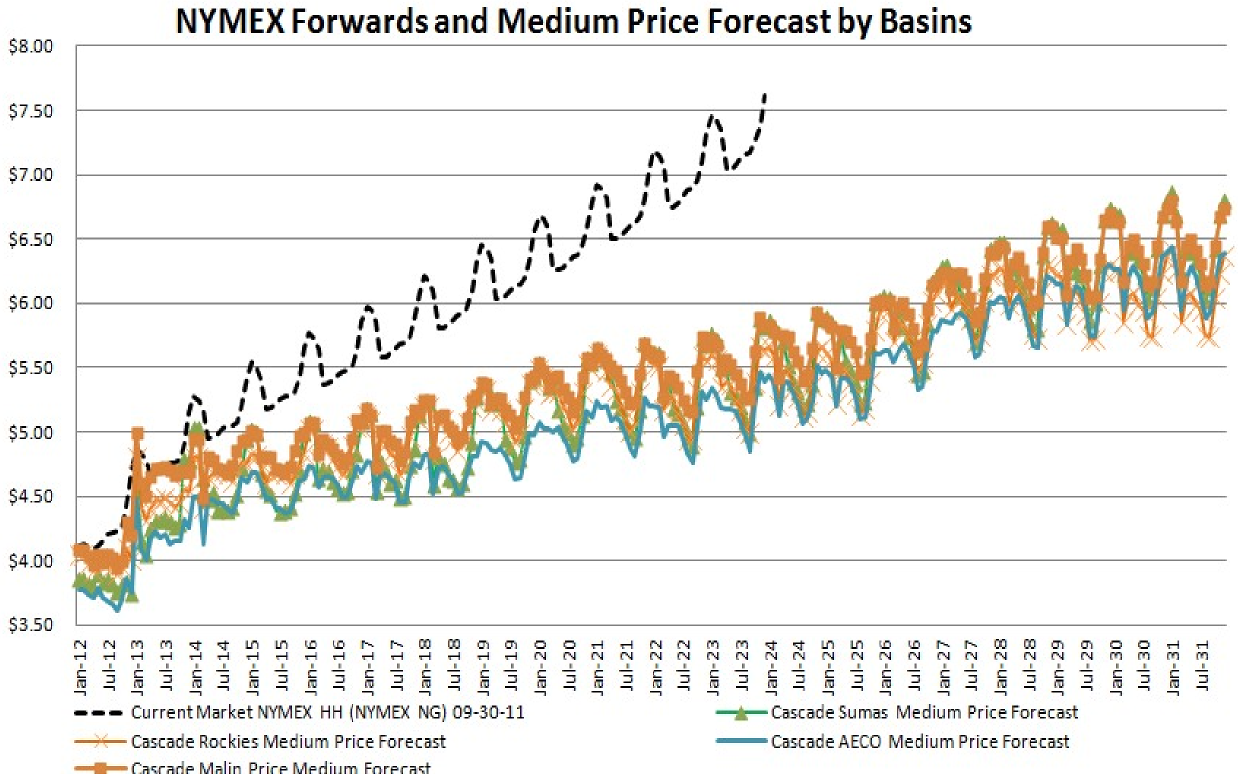
In order to determine the low case and high case, the Company utilized the EIA economic growth factors (EIA Annual Energy Outlook 2011, Table E-1). This resulted in using 2.1 for the Low Case, 2.7 for the Reference Case and 3.2 for the High Case.

TABLE 5-3
HENRY HUB FORECAST WEIGHTING FACTORS

Year	Financial Forecast Center	NWPPC	TEXAS Comptroller	WoodMac	EIA	NYMEX HH
2012	0.50%	8.00%	0.50%	8.00%	8.00%	75.00%
2013	0.50%	8.00%	0.50%	8.00%	8.00%	75.00%
2014	0.50%	8.00%	0.50%	14.50%	14.50%	62.00%
2015	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2016	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2017	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2018	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2019	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2020	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2021	0.00%	30.00%	1.00%	14.50%	14.50%	40.00%
2022	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2023	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2024	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2025	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2026	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2027	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2028	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2029	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2030	0.00%	30.00%	1.50%	30.00%	18.50%	20.00%
2031	0.00%	0.00%	45.00%	0.00%	55.00%	0.00%

Figure 5-D on the following page provides a summary of the medium price forecast (in real dollars) for the various indices over the 20 year planning horizon. Appendix E provides the detailed 20 year price forecasts.

FIGURE 5-D



Supply Side Resource Uncertainties

Several uncertainties exist in evaluating supply-side resources. They include regulatory risks, deliverability risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission or Canada's National Energy 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 when the decision was made. Price risks associated with climbing prices can be minimized through the use of fixed price contracts or through the use of financial derivatives.

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, in response to competitive pressure on their mainline tolls, TransCanada Pipeline filed with the NEB to extend NOVA service east to Steelman and west to Kingsgate. This includes the roll-in of Foothills Pipeline. Under the plan, TCPL estimates western shippers (i.e. Cascade) will save between 5-7 cents including fuel. Eastern shippers will also see reduced rates while receipt shipper rates will increase 3-5 cents. Increases in costs for receipt shippers led to concerns that commodity prices for future gas supplies on the Alberta system may raise substantially. The Company will continue to monitor and be actively involved in the various pipeline forums as these initiatives develop.

As noted earlier, demand in Asia will likely make LNG exports from the Pacific Northwest a competitor for natural gas. It is also important to note an increasing trend in the use of natural gas vehicles (NGV) which utilize natural gas that has been compressed into a transportation fuel, also known simply as compressed natural gas. Taxis, transit and school buses, as well as heady- duty trucks are among the users of natural gas powered vehicles. The Natural Gas Vehicle Institute estimates there are more than 112,000 NGVs in the United States. Plentiful reserves of natural gas exist as a domestic fuel, typically at substantial discounts compared to gasoline. From an environmental impact, exhaust emissions are generally much lower than gasoline powered vehicles. 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.

According to the January 2012 Alternative Fuel Price Report from the Department of Energy, compressed natural gas had a price differential of between $1.50 and $2.25 compared to gasoline prices in Washington and Oregon. Several compressed natural gas fueling stations exist in the Seattle Metropolitan area; additionally, Avista has an active NGV fleet program in the works. While we have yet to see the demand for NGVs create notable competition for natural gas in the Pacific Northwest (although there are estimates that over 12 million NGVs exist world-wide), as technology improves and costs of fueling stations become more economical there exists the probability that NGV use will put pressure on future gas prices and availability. Cascade will continue to monitor activities in the NGV sector for possible impacts to our resource planning.

Financial Derivatives

Cascade constantly seeks methods to ensure ratepayers 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 hedges, or financial derivatives. The general concept 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 New York Mercantile Exchange (NYMEX). The use of futures allows parties to lock-in a known price for extended periods of time (up to 6 years) in the future. Contracts are typically made in quantities of 10,000 dekatherms to be delivered to agreed-upon points (e.g., Sumas, Station 2, AECO, Northwest Pipeline 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 idea is to level the price over the long term. Futures and swaps are typically called “costless” because they have no up-front cost.

Unlike futures and swaps, an option on futures only provides protection in one direction—either against rising or falling prices. For example, if Cascade wanted to protect itself against rising gas prices but keep the ability to take advantage of falling prices, Cascade can 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.

Portfolio Purchasing Strategy

Cascade’s Gas Supply Oversight Committee (GSOC) oversees the Company’s gas supply purchasing strategy. Beginning with the 2004/05 gas supply portfolio, Cascade has employed a more rigorous gas procurement strategy for both physical gas supplies and for hedging the price of the core portfolio. Cascade has contracted for physical supplies for up to three years (based on a warmer-than-normal weather pattern). The Company’s current gas procurement strategy is to have physical gas supplies under contract for 100% of year one’s warmer than normal core needs, 66% of year two, and 33% of year three. This strategy results in the need to contract annually for approximately one-third of the core portfolio supply needs for the upcoming three-year period. Under this procurement strategy, this leaves roughly 10 to 20% of the annual portfolio to be met with spot purchases. Spot purchases consist of either “First of the Month” deals executed during bid week for the upcoming month, or day purchases which are utilized to meet incremental daily needs.

Once the portfolio procurement strategy and design has been approved by GSOC, the Company employs a variety of methods for securing the best possible deal under existing market conditions. Cascade employs a bidding process when procuring Fixed physical, Indexed Spot physical, as well as financial swaps used to hedge the price of index based physical supplies. In the bidding process we alert a minimum of three suppliers and/or financial counterparties of the specific gas supply transactions Cascade plans to fill. We then collect bids from these parties over a period of days or weeks depending on the number or time requirements of 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 will award 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 we ensure party diversity. It should be noted that there is always the possibility the lowest market price may be during a period when we are 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.

GSOC also oversees the Company’s gas supply hedging strategy. The Company’s current gas hedging strategy is to hedge 45% of the contracted physical supplies of Year

One, 30% of Year Two and 15% of 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 higher level. Currently, depressed market prices have significantly reduced the need for financial swaps; the Company's current strategy is to rely primarily on fixed-priced physical supplies for hedging purposes.

Cascade's programmed buying approach has Cascade negotiating with suppliers and/or financial institutions throughout the year, loosely grouped during three specific time periods (Spring, Summer, and Fall). Ideally, the periods are designed so that each pricing basin (Sumas, Rockies, AECO) has financial swaps or fixed-priced physical supplies in each of the three buy periods. Typically, financial swaps are contracted in amounts in standard blocks of 10,000 dths. While it is possible to contract for other amounts, deviating from the standard blocks could potentially result in having to pay a premium as it is harder for the financial institution to hedge that odd amount with one of their counterparties. As a relatively small LDC, Cascade's ability to hedge in standard blocks is severely limited. Dividing the blocks into numerous smaller or odd sizes would incur increased transactional costs. In fact, some trading partners will not even consider executing a transaction that has varying volumes or are of a non-standard size. Consequently, Cascade's procurement and hedging periods are designed with these concerns in mind while trying to ensure that the total notional volume to be contracted is spread as equally as possible across the buy periods.

Utilizing the consistency of a programmed buying method as described above should help ensure that any locked-in prices provide stability over time, in addition to preventing Cascade from being over or under hedged. In the current contract year and beyond, Cascade plans to annually review our gas procurement physical and hedging strategy and, if unchanged, the company would continue its physical and hedging strategies as outlined above.

Cascade believes its gas procurement strategy is achieving diversity and flexibility in its gas supply portfolio through a combination of physical and financial structures. This goal encompasses not only supply basin origination and capacity limitations, but also includes a combination of pricing options that will assist Cascade in minimizing exposure to price volatility. The programmed buying approach to locking in a significant portion of gas prices maintains a market sensitive and balanced supply portfolio that continues to represent stable pricing as well as secure physical supplies for the Company's core customers.

Section 6

Demand Side Resources

Introduction and Overview

Demand Side Management (DSM) resources are generally thought of as conservation measures or actions that result in the reduction of natural gas consumption due to increases in efficiency of energy use or load management. Oregon and Washington Utility Commissions require gas utilities to consider cost-effective DSM resources in their energy portfolio on an equal and comparable basis with supply side resources. In the gas industry, DSM resources are conservation measures that include but are not limited to ceiling, wall and floor insulation, higher efficiency gas appliances, insulated windows and doors, ventilation heat recovery systems and weather stripping to name a few. By prompting customers to change their demand for gas, Cascade can displace the need to purchase additional gas supplies, displace or delay contracting for incremental pipeline capacity and possibly displace or delay the need for reinforcements on the Company's distribution system.

There are two basic types of demand side resources. These are baseload resources and heat sensitive resources. Baseload options are those that displace the need for baseload supply-side resources. They will offset gas supply requirements day in and day out regardless of the weather. Baseload DSM resources include high efficiency water heaters, higher efficiency cooking equipment and horizontal axis washers. Heat sensitive DSM resources are measures whose therm savings increase during cold weather. For example, a high efficiency furnace will lower therm usage in the winter months when the furnace is utilized the most and will provide little if any savings in the summer months when the furnace is rarely used or is turned off. Examples of heat sensitive DSM measures are ceiling/floor/wall insulation measures, high efficiency gas furnaces, and improvements to duct work. These types of measures will offset more of the peaking or seasonal gas supply resources, which are typically more expensive than baseload supplies.

Note on Technical Potential in Oregon: Technical potential for heat sensitive measures remains viable into the 2012 IRP planning period with the levelized cost for insulation, hearths, furnaces, and weatherization measures below the ETO avoided cost limit of $1, and the Company's cost limit of $.75. More details regarding the cost-effectiveness of these measures in the State of Oregon can be found on Tables 6-2 and 6-3.

It should be noted that the ETO has reported blended cost-effectiveness achievements for the two gas utilities they serve at levels more conservative than those listed above, with an ETO Conservative Goal of $.47 levelized cost for 2012. In turn, the OPUC, via Docket UM 1158, has enacted an ETO Performance Measure of $.52 levelized costs or lower. While this is not an unreasonable guideline for assessing the *combined* levelized cost threshold for conservation efforts on behalf of Cascade Natural Gas and Northwest Natural, the benchmark would be less realistic if treated as an individual, utility-specific goal for conservation achievements exclusive to CNGC's service territory.

More specifically, the $.52 cost-effectiveness threshold is not directly applicable to the Company based on its current avoided costs and cost-effectiveness threshold (see appendix

H).This metric is even more difficult to achieve if calculations include administrative and programmatic expenses (which would be the case for an equivalent utility-run program).

However, it is the Company's understanding that lower levelized cost metrics reported by the Trust *do not* include any of the following; program management, program incentives, program payroll and related expenses, call center, or program outsourced services. With these fundamental expenses included, it is more realistic and appropriate to anticipate a levelized cost in the $.75 range, which the Company believes is appropriate relative to natural gas pricing forecasts and the desire for continued adaptability to long-term changes in the cost of gas and future costs of carbon. Applying the blended benchmarking target of $.52 would result in a more limited program for CNGC customers and preclude several residential measures including but not limited to the consideration of windows and tank water-heater upgrades. Residential technical potential would be reduced by approximately 1.8 million therms. Solar Hot Water would also remain precluded due to cost-effectiveness limits (although the ETO still provides incentives for this measure due to its perceived non-energy benefits). On the commercial side of the Oregon conservation portfolio, screening conservation potential at the $.52 limit would eliminate several key commercial gas conservation measures including Ozone Laundry Treatment, controls, power burners, and condensing furnaces, among other measures. Commercial technical potential would be reduced by approximately 163,228 therms or 13.3 percent of the total. The addition of administrative and programmatic costs would result in further reductions to program potential, resulting in possible lost opportunities for deeper natural gas conservation in Cascade's service territory. As this time the ETO does not appear to anticipate the need for revised targets or funding levels commensurate with the more stringent performance metrics.

Energy Trust's levelized cost projections for Cascade ($0.62/therm) are 32% higher than those for NW Natural ($0.46/therm) as provided in the conservative case goals in the 2012 budget and action plan. Because the CNGC total savings goals are 8% of Energy Trust's total Oregon IRP gas savings goals but 9.7% of the budgeted dollars, the resulting combined levelized cost goal is more heavily weighted to the lower levelized cost projection of NW Natural.

Costs to deliver savings in CNG territory are higher for several reasons. CNG's territory is more rural than NW Natural's, contractors need to travel greater distances to complete the same work and there is less competition in the contractor pool. With fewer project opportunities, the economies of scale seen in delivery among densely populated regions is not seen in CNG territory. 80% of CNG's program mix has higher delivery costs than similar programs in NW Natural territory, including new and existing buildings and all residential offerings. Only industrial savings is projected to have a lower levelized cost than NW Natural industrial in 2012.

Although NW Natural's levelized costs are lower, Energy Trust is committed to meeting CNG's overall and program specific savings goals within budget and sees no advantage to more heavily weighting savings performance in NW Natural territory over CNG territory. If it costs less than forecasted for Energy Trust to deliver the CNG savings goal, there will be a minor cushion in cost performance translated to NW Natural. The CNG budget and goals drive Energy Trust to manage costs by limiting total dollars available to deliver savings goals. Energy Trust's short term strategy for keeping costs within projections is to manage programs closely, and, as needed, shift resources between programs in consultation with CNG.

Due to differences in the approach to DSM acquisition between Cascade's Oregon and Washington jurisdictions, each of the states will be addressed individually. In Oregon, the Company has a fiduciary responsibility to evaluate the funding adequacies of its public purpose charges that go to the Energy Trust as well as the Company's own low-income programs. In Washington, Cascade is updating the technically achievable conservation potential in its Washington service territory.

2-Year Action Plan Update

Oregon Conservation Programs and the Energy Trust of Oregon

Since July 2006, Cascade has relied on the Energy Trust of Oregon (ETO) for the delivery and administration of its conservation programs in Oregon. As the delivery agent for gas conservation efforts in customer homes and facilities on qualifying rate schedules 101 and 104. as well as some industrial efforts, The Energy Trust of Oregon has played a prominent role in both the establishment of the ETO's annual therm savings targets in the Company's service territory, and the determination of needed funds to acquire those therm savings. As reported by the ETO in their annual report to the Oregon Public Utilities Commission (OPUC), the 2010 therm savings achievement in Cascade's service territory was 367,875 (including market transformation savings of 57,616 therms), just shy of their annual goal for that year, but above their IRP target for the same timeframe. Spending was $1.3 million, a notable reduction from their initial estimates. The ETO estimates that their 2011 achievements will be on par with their existing IRP target of 391,754. The preliminary stretch target established for 2012 is 409,372 therms (without market transformation) and the conservative goal is 347,966. These goals are expected to be achievable despite the ETO's significant downward revisions to the 20 year therm savings potential for the Company, and more stringent performance metrics from the OPUC. See addendum for additional comments regarding limitations for assessing DSM Potentials and Cost Effectiveness

Oregon Public Purpose Fund

Commensurate with an increase in the Public Purpose charge, as of November 1, 2011, 88% of monies designated as public purpose funding are now transferred to the Energy Trust of Oregon for the purposes of designing, promoting, and administering Natural Gas energy efficiency programs in accordance with agreements executed between Cascade and the Energy Trust. 12% of the monies designated as Public Purpose Funding is transferred to two internal program accounts and dispersed to Community Action Agencies for the purpose of delivering Cascade's low income weatherization and bill assistance programs.

Recent activities pertaining to the Oregon Public Purpose fund and other monies collected for the purposes of conservation within CNGC's service territory can be found below:

- On August 11, 2010, the Commission approved Order No. 10-309, Cascade's request for authorization to defer incremental funding of Public Purpose Funding payable to ETO to support conservation. This order granted Cascade authorization to defer an amount of funding not to exceed $950,000 for a period of 12 months. Because actual achievements and expenditures did not meet the estimates, the ETO entered 2011 with $526,412 of carryover funds available to meet its 2011 budget.

- ETO's 2011 budget for Cascade was $2,497,836 to deliver its projected annual savings of 391,754 therms. ETO entered 2011 with $526,412 in carryover funds from the 2010 program year. Public purpose funding from Cascade was estimated to be around $886,000.   On paper, this would leave ETO short of funding for program year 2011 by around $1,085,000 –leaving nothing toward the 5 percent reserve that ETO prefers to enter into each new program year with. In this case, the 2011 planning reserve was an additional $124,892, or 5 percent of the $2,497,836 budget. Cascade continued to work closely with ETO staff toward the end of 2011 in order to most effectively calibrate the final provision of deferred funding so as not to provide an excess of funding should the expenditures finish below budget for 2011.

- On August 3, 2011, the Commission approved in Order No. 11-285, Cascade's request for authorization to defer incremental funding of Public Purpose Funding payable to ETO to support conservation. This order granted Cascade authorization to defer an amount of funding of up to $1,300,000. This additional deferred funding enabled Cascade to be able to adequately fund ETO's planned budget needs for 2011 and provide a sufficient cash reserve at the end of the year.

- On September 30, 2011, the Company filed changes to its Rate Schedule 31 "Public Purposes Funding" tariff. The 1.69% adjustment, made effective November 1, 2011, was filed at the request of the Energy Trust in order to meet the organization's program expenditure requirements.

Based on recent requests and increased program expenditures from the Trust, the Company anticipates that there will still be a need for additional funding during 2012 in addition to the recently approved increase in the Public Purposes charge and the remaining authorized amount of deferred funding. Cascade will shortly begin joint discussions with Staff and ETO to determine the best solution going forward. Cascade will then make the appropriate application(s) for an additional increase in Public Purposes funding and/or a re-authorization of deferred accounting treatment later in 2012 as the ETO budget becomes firm and the actual program expenditures become known.

Oregon Low Income Weatherization Program

From January 1st through December 31, 2010, 133 homes have been weatherized in Oregon with an annual cumulative savings of 21,401 therms and with $263,474.12 provided in rebates. Average savings per home is 160 therms annually. This represents a significant growth in program participation and low-income CNGC households served during the calendar year. This increased momentum reflects in part a strengthened relationship between CNGC and the Community Action Agencies (CAAs) delivering the Weatherization Assistance Program (WAP). The *most* significant factor to this ramp-up has also the availability of ARRA dollars to the Agencies to serve more low income households in the State of Oregon. Leveraged against CNGC rebate monies, the WAP has been able to serve a significantly higher number of Cascade customers than in prior years. From January 1st through September, 2011, Cascade's Oregon Low Income Energy Conservation Program (OLIEC) has served 65 homes and achieved a savings figure of approximately 8,657 therms with a total expenditure of approximately $107,113. This is slightly lower than the achievement numbers from the same time in the prior year, reflecting the impending expiration of the ARRA monies, but still a significant upward improvement from the previous level of savings to CNGC low income households.

Cascade continues to work closely with its Oregon Low Income Advisory Group to better understand the capacity of the WAP (Weatherization Assistance Program) to serve Cascade homes and evaluate strategies designed to maintain active Agency participation in the program either through modifications to the program measures, incentives, or delivery approach. Such utility collaboration will become particularly important in light of impending reductions to both ARRA and other critical federal funding sources.

Program modifications discussed with the Advisory Group and implemented in 2010 included an extension of the OLIEC program to incorporate rebates for high efficiency natural gas water heaters, and allow participation by non-profit entities engaged in providing affordable, energy-efficient housing for low-income individuals. Cascade will continue its efforts to identify opportunities to utilize the available OLIEC funds in a manner that achieves the greatest amount of cost-effective therm savings at homes occupied by low-income households.

Outside Determinants of Customer Usage

Cascade has remained active in monitoring external developments at the state and national level which carry potential impacts to customer usage within our service territory. Such developments include changes to Residential and Commercial building codes. Several substantial changes to Washington code were scheduled to go into effect on July 1, 2010 but have experienced subsequent delays. These changes are likely to have direct impacts to the operation of our Conservation Incentive Program. The Washington State Building Code Council will enter into regular rulemaking to determine whether implementation should be further delayed until April 1, 2011. Measures resulting from this new code that have the potential to impact Cascade's Conservation Incentive Program are outlined as follows:

- *PTCS Duct Sealing (Residential- Existing)* – A duct sealing standard equal in stringency to the PTCS standard will become mandatory. Code will mandate this new standard be enforced whenever homeowners make space conditioning alterations to their home. A space conditioning alteration is defined as any change to the heating and air conditioning equipment (i.e. replacing a furnace).

  The technical potential for the Company to claim savings from this measure is no longer viable since it will soon be mandated by the State. Therefore potential for gas savings to 2030 is reduced by approximately 790k therms (or the amount Stellar associated with this measure). The inclusion of potential from PTCS duct sealing is still viable as a stand-alone measure that would not be combined with a furnace replacement or other space conditioning alternation, but should be reduced downward to reflect that measure potential is now limited to existing homes where space-conditioning equipment has not been altered.

  PTCS Duct Sealing (Residential- New) - On average, 56% of the deemed savings associated with ENERGY STAR certified homes comes from insulation and duct sealing. If the new code equals or exceeds insulation and duct sealing standards for ENERGY STAR certified homes, it may be necessary to reduce the deemed savings (and total technical potential for the CIP) associated with this measure. However this may be somewhat offset by therm savings increases, as ENERGY STAR home requirements may become more stringent in 2011.

  As a means of trying to prepare our contractors for the upcoming changes, CNGC contractors have made numerous calls to builders, HVAC contractors, and insulation contractors. These calls were used to inform program participants of the upcoming code changes, WSU trainings available, and the Trade Ally equipment discounts. Feedback from contractors and builders has made it clear that a small number of contractors feel prepared to comply with these code changes in 2010 and both compliance and enforcement of these codes may take a while to be consistent.

Windows (Commercial) **-** The proposed 2009 WA State Energy Code will eliminate most of the new building window measures proposed in the Stellar report by virtue of requiring a reduction of U values (overall heat transfer coefficient). The old code allowed U values for windows of .55 Btu/sq ft, and the Stellar report used reduced U values ranging from .45 to .31 for modeling their new window measures. The new code stipulates maximum U values of .40 for aluminum frame windows (eliminates potential new window measures E129, E130, E126, E127 in Stellar) and .32 for vinyl windows (eliminates new window measures E123 and E124). This only leaves E131 and E128 for Aluminum frame windows and E125 for vinyl windows, but with commensurate greatly reduced efficiency gains over newer code requirements.

Oregon Building Codes

While code changes, and their impacts to conservation potential, are primarily monitored by the Energy Trust of Oregon, Cascade also reviews these upcoming changes in order to better understand the viable conservation incentive opportunities that can be offered to its customers. Most code changes apply only to new construction or substantial home/facility remodels, and thus it is often critical to maintain incentives for high-efficiency residential gas measures in existing construction even while code tightens. In fact, during times of transition to more stringent code, there may be motivation by manufacturers to “push” lower-efficiency equipment in existing structures/dwellings as demand for the equipment is reduced in the new and remodeling market segments. In a service territory such as Cascade’s customer gas equipment purchases are often driven by cost-signals. Thus incentives are an excellent way to further ensure the installation of high-performance equipment and measures that *exceed* the code levels for existing construction and avoid lost opportunities for deeper therm savings.

The OR Building Code Division last updated the Oregon Residential Specialty Code (ORSC) in July, 2011 requiring 10% more efficiency than the previous code had. The energy efficiency code (OEESC- Oregon Energy Efficiency Specialty Code) was last updated in 2010. The next round of building code revisions for commercial properties will begin in 2012 with execution occurring in 2013. This series of updates generally reoccurs a year after the three-year International Code Council model code is updated -enabling us to periodically monitor probable changes in the codes. Cascade will continue to monitor these changes as they develop.

Gas Heating Potential and UM 1565

During the time of preparing this IRP, the Company is actively engaged in deliberations with the OPUC, Energy Trust of Oregon, and Electric and Natural Gas utilities participating with the

ETO in Fuel Switching Docket UM 1565. The outcomes of this regulatory examination may have significant impacts on natural gas conservation potential within CNGC's service territory for the following reasons; (1) the formalization of the current active promotion and proliferation of incentives for electric heat pumps, and the discontinuation of incentives for gas space heat measures, may permanently eliminate opportunities for the installation of high performance natural gas equipment in these dwellings, thus requiring a downward assessment of residential conservation potential; (2) more formal guidance as to whether the market for natural gas furnaces has been fully and effectively transformed in CNGC's service territory may ultimately result in the need to upwardly or downwardly adjust the Company's understanding of technical potential for this measure.

Impacts of Governor's 10 Year Energy Plan in Oregon

At the time of the CNGC 2011 Oregon IRP cycle, the State of Oregon is engaged in a comprehensive series of policy changes with potentially significant impacts to statewide energy usage, carbon mitigation strategies, and other environmental goals. The planning and execution of the Oregon Energy Task Force's recommendations to Governor John Kitzhaber have not yet been finalized, but it is anticipated that the outcomes may heavily influence utility DSM policy, existing energy codes, and perceptions regarding optimal fuel mix and natural gas usage in the state. There is also discussion of aggressive carbon regulation and emissions caps which may ultimately serve to increase the range of viable conservation measures commensurate with the inclusion of carbon-adders to the avoided cost of natural gas. Cascade Natural Gas is monitoring these developments closely and will work with the Energy Trust of Oregon and/or other participating entities in order to serve as environmental stewards, optimizing the use of natural gas and energy efficient natural gas measures and technologies to the fullest extent possible.

Washington Program Cost Effectiveness & Emerging Technologies

As the energy efficiency market continues to develop, and conservation technologies become more prevalent, the efficiency, availability, and costs of such measures may evolve over time. The Company continues to work closely with its Program Management Engineers to monitor such changes and determine the most prudent course of action for our Conservation Programs.

An example of an emerging technology that has become affordable and market-accessible within Cascade's service territory is the 90%+ Combo Heat/Water Heat System utilizing a high-efficiency condensing tankless water heater. Over the course of several years, this measure has come down in cost and has become increasingly available within Cascade's service territory. As a result, this promising measure was added to the CNGC conservation portfolio in 2009.

In addition, the Company has also raised the R-values (a measure of insulation's ability to resist heat traveling through it) eligible for rebate in its Commercial/Industrial program, creating two tiers of incentives. An incentive was added for certain boiler steam traps; the incentive was raised for high efficiency boilers, and adjustments were made to the standards and inputs of boilers and furnaces as appropriate.

Following the Company's 2-Year Action Plan, Cascade continues to monitor the viability of .70 conventional water heaters and other emerging technologies in order to assess their applicability to our service territory. If, and when, such measures become market available, we will take steps to include them in our conservation portfolio.

Impacts of Washington's Climate Change Challenge

Since Governor Gregiore announced the Executive Order creating Washington's Climate Change Challenge in February 2007, Cascade has monitored the progress of the Challenge as it pertains to the Utility. On September 23, 2008, the Western Climate Initiative (WCI) released its Greenhouse Gas Cap and Trade design recommendations. WCI participants, which include both Washington and Oregon, have a certain amount of flexibility in setting requirements for implementation, compliance, and enforcement of the program. However key recommendations from the WCI are described in the following statements:

- Reduce GHG emissions to 15% below 2005 levels by 2020
- GHG measurements and monitoring begin 1/1/10 for reporting in early 2011
- First compliance period begins 1/1/12- electric generations (including imports); industrial and commercial combustion; industrial process non-combustion emissions
- Second compliance period begins 1/1/15- residential, commercial, and industrial fuel combustion below 25,000 metric ton threshold; transportation fuel
- No set date for allowance allocations, but they will be established prior to 2012
- Encourage entities to reduce GHG emissions 1/1/08-12/31/11 by issuing Early Reduction Allowances that are in addition to allocated allowances and are treated like allocated allowances

Since the 2008 IRP, the Washington Department of Ecology has moved forward with enacting Executive Order 09-05 *Washington's Leadership on Climate Change* which went into effect May 21, 2009 and directs state agencies to, among other deliverables:

- Continue to work with six other Western states and four Canadian provinces in the Western Climate Initiative to develop a regional emissions reduction program design;

- Work with companies that emit 25,000 metric tons or more each year to develop emission reduction strategies; and

- Work with businesses and interested stakeholders to develop recommendations on emission benchmarks by industry to make sure 2020 reduction targets are met.

During the 2009 Washington Legislative Session, Legislators passed Engrossed Second Substitute Senate Bill 5854 (E2SSB 5854) that amended Chapter 19.27A RCW with the intent of assisting with the implementation of Order 09-05 by tracking energy consumption in buildings. State agencies, colleges, universities and non-residential facilities encompassing more than 10,000 square feet of conditioned space are now directed to track usage with the US Environmental Protection Agency's Portfolio Manager. To facilitate this tracking, the Legislature has directed all electric and natural gas utilities with more than 25,000 WA customers to provide energy consumption information, upon request, for all non-residential and qualifying public agency buildings to which they provide service. In compliance with this mandate, Cascade has begun to provide this critical information as requested.

Following a WCI benchmarking symposium held on May 19, 2010, stakeholders to this initiative have developed a final white paper which explores "Issues and Options for Benchmarking Industrial Greenhouse Gas Emissions". According to the paper, State and federal policy makers are still considering several approaches to achieving emissions benchmarks (once finalized) including the use of Voluntary Performance Goals, a "Cap and Trade" system, or Regulatory GHG performance standards. Since the nature of such benchmarks and final method of delivery are still unknown, Cascade is not yet fully able to anticipate how this initiative will affect the Company and its customers. However, it is likely that we will have a clearer picture of next steps and impacts as we move closer to the Governor's benchmarking deadline of July 1, 2011.

Already, the impacts of benchmarking and pending legislation are being felt across the state. Electric utilities such as Puget Sound Energy have begun to actively implement "Direct Use" efforts in anticipation of impending climate change legislation. Since Direct Use is often the most prudent use of energy resources, the Company will carefully monitor how environmentally responsible load switching of this nature would be treated under a cap-and-trade scenario.

Additionally, the code changes discussed earlier (and poised to take effect in late 2010/early 2011) are also a direct product of Washington's aggressive climate change efforts. Such increases in efficiency resulting from code would preemptively capture high percentages of the savings potential outlined in Cascade's conservation potential study, but would not be attributable to the Company itself.

Because the final design, breadth, and ultimate impacts of climate change legislation are yet unknown, the Company is examining bundles of measures which become cost effective under different price indicators. This will prepare us to adapt as appropriate in the future.

Potential DSM Measures and Their Costs

The first task in designing any DSM program is to analyze and determine costs and the associated energy savings for conservation measures along with estimating their applicability within Cascade's service territory. Evaluating specific measures involves ranking measures by levelized cost per therm saved. Levelized cost is a straightforward calculation that considers the incremental cost of a measure divided by the discounted therm savings. This calculation allows the Company to better screen technical potential in order to include a broad range of measures with potential conservation benefits to Cascade's customers. Each measure's cost and estimated therm savings are compared to supply side costs over a 20-year planning horizon. Administration expenses are included only in total program costs, not in measure costs and are expected to vary by program type and duration. The levelized cost test is a helpful tool for understanding the range of measures that *could* be cost effective contingent upon the avoided cost of natural gas during the planning period. Thus, there is value to maintaining a database of potential conservation measures sorted by levelized cost and reexamining them periodically as avoided costs increase or decrease.

Once measures have been run through levelized cost testing, and screened based on current avoided costs, the Company (or entity operating on the Company's behalf) is then able build a portfolio of prescribed offerings. These offerings are assessed based on the most recent data pertaining to the incremental costs and therm savings of the measure, In the State of Washington the Company also uses the TRC test to assess cost-effectiveness in the context of all programmatic and administrative expenses incurred in relation to the operation of its Conservation Incentive Program. To the best of the Company's knowledge, programmatic expenses are not included in assessments performed by the ETO. A total resource cost (TRC) approach is used to evaluate the cost-effectiveness of all DSM resources. The TRC method compares total net costs of DSM resources to the total net cost of supply side resources displaced. A program or measure is cost-effective if the present value of energy savings and non-energy benefits derived from installing that measure is greater than the total resource cost (TRC) of the program or measure. Non-energy benefits may include, for example, water savings from low-flow showerheads and higher efficiency clothes washers or reductions in maintenance costs. The TRC screening is utilized at the portfolio planning level.

Another tool used to assess the overall cost-effectiveness and benefits of measures within a conservation portfolio is a Cost Benefit Ratio Test. This test assesses the value of a proposed measure by comparing the savings achieved over the lifespan of the measure to the installed cost of the measure (sans non-energy benefits) by dividing the benefits by the costs. If the CB ratio is higher than one, the measure is considered cost effective.

As stated in previous IRPs, the Company's conservation potential (both "technical" and "achievable") was initially determined through a comprehensive study performed by Stellar Processes in conjunction with Ecotope in 2006. This study expanded upon the findings of the Energy Trust of Oregon and further assessed the breadth of available conservation opportunities within Cascade's service territory.

An assessment of all energy savings that could be accomplished in the absence of market barriers such as cost and customer awareness (technical potential) was formulated by Stellar/Ecotope by examining the baseline usage of customers by building type and sector to better understand the savings that could be achieved by measure and portfolio. The study provided analysis to determine the feasibility for utility customers to engage in *specific* conservation activities and measures. Applicability of some measures might depend on the fuel for space heating, for example. Also, the amount of remaining potential is affected by the extent to which the market of a specific product is currently saturated. Utility forecasted growth was then applied to estimate the amount of structures with conservation potential in future years. The study then aimed to quantify energy usage by customer sector (commercial, industrial, residential) and then by the customer type within each sector (single family, small office, wood products, etc). The Energy Trust further refined the assessment of technical potential within Cascade's service territory based on their understanding of the energy/equipment markets and their prior experience operating such programs in the State or Oregon. Outcomes were then translated into an assessment of achievable potential, or what conservation is feasible under "real world" conditions and takes into account customer awareness, participation, and economic constraints.

In 2008, Stellar was once more approached by the ETO to refine savings and cost estimates for previously identified measures. It also explored the feasibility of new and emerging technologies that were unavailable during the original study. A January 2011 report prepared for the Trust (entitled "Energy Efficiency and Conservation Measure Resource Assessment for the years 2010-2030") offered several major revisions to previous understandings of the Company's conservation potential and has led the ETO to offer a significant reassessment of conservation potential over the 20 year outlook. This study was modified for the Cascade Natural Gas service area in July 2011 and again in September, 2011 to help refine and assess the estimates of long-term technical therm savings potential. Further description of these changes can be found in the paragraphs below as well as under Appendix D**.**

One prominent change to the most recent conservation Assessment is the appearance of a major reduction to natural gas conservation potential due to significant adjustments to previous assumptions. The new report also includes the use of "Benefit Cost Ratio" as a screening criterion to determine cost-effectiveness as opposed to the strict use of levelized cost. The BCR model is comprised of the Net Present Value of Benefits divided by Total Resource Cost. This change is more significant for electric measures which would not be covered under a CNGC Gas Conservation effort since it takes savings during peak period into account.

The 2011 Stellar Assessment further notes that, at the direction of Energy Trust Staff, “program related costs” were not included as a factor in cost effectiveness screening of the individual measures as it was noted to be outside the scope of the Study. The levelized costs utilized in the Study do represent the total societal cost of efficiency measures (sans admin expenses). The Study indicated that they have provided “the basic information on the costs of measures, which the Energy Trust will combine with their knowledge of markets and programs and incentives to develop estimates of total program costs to society and (separately) to the utility system”. Most of the proposed measures in the study fall within the cost-effectiveness screen with the “one large exception [of] solar water heaters which remain expensive even after tax credits” according to the Stellar Report. The report goes on to explain that “Energy Trust has found solar water heat to be cost-effective using a more complex cost-effectiveness methodology than the simple first cut approach employed in this study”. The Company is in conversation with the Energy Trust regarding the methodologies surrounding the complex assessment and how they could be best employed to measure other innovative but less commonly available conservation measures such as natural gas heat pump technology.

For the residential sector, Stellar/Ecotope continued to apply prototype models over the climate zones developed in the original study. This was done in order to estimate major end use consumption, calibrated to actual sector consumption. Table 6-1 shows the climate zones utilized and the areas in Cascade's Washington and Oregon Service territory assigned to each zone.

Table 6-1
CLIMATE ZONES

WASHINGTON				**OREGON**	
ZONE 1	**ZONE 2**	**ZONE 3**		**ZONE 1**	**ZONE 2**
Bellingham Mount Vernon	Aberdeen Bremerton Longview	Sunnyside Tri-Cities Walla Walla Wenatchee Yakima		Bend	Baker Ontario Pendleton

For the Commercial sector, EUI factors provided consumption by end-uses and were based on information developed from a Washington Natural Gas study prepared in 1995. For the industrial sector, Stellar developed sharedown fractions that allowed therm sales to be applied towards specific end-uses.

Following the comprehensive examination of all cost-effective and realistically achievable measures, the Company (in WA, and Energy Trust in OR) was able to estimate attainable program ramp-up rates that consider marketing, technology delivery channels, and other program constraints to develop a 20-year DSM deployment scenario with year-by-year achievable savings. This timeframe, and all associated potential, have been adjusted for the 2011 IRP to consider the final updates made to the most recent Stellar/Ecotope study referenced earlier in this document. As a part of updating the Washington study, Cascade revised the forecasted growth rates utilized in Stellar's original study with the current expectations for growth in both the residential and commercial/industrial sectors. The forecasted growth rate is based on the most recent demand forecast detailed in Section 4 of this plan.

Oregon Conservation Study Results

The complete list of the measures and their applicability to Cascade's Oregon Service territory is included in Appendix D. It is important to recognize that the cost-effectiveness limits included in the IRP represent the Company's best understanding of the future cost of natural gas projected during the current planning period. Future influences on the price of natural gas, such as carbon taxes or similar regulatory mechanisms could lead a broader spread of conservation measures to become cost effective in the future. It is therefore prudent to offer an initial measure screen at a higher level than current levelized cost limits. Understanding the available spread of valuable, but "borderline cost-effective" measures allow the Company (or in the case of Oregon, the Energy Trust) to be prepared to smoothly adapt its conservation portfolio to capture *all* cost-effective natural gas conservation opportunities in the event that economic circumstances permit a more generous screening of DSM potential.

For purposes of the Oregon study, the ETO chose to include measures which screen at $1.00 levelized cost. This threshold exceeds the Company-developed cost-effectiveness limits in the Basecase Median Forecast as outlined in Appendix H**,** Avoided Cost Calculations. This calculation considers the annual portfolio cost per therm, nominal cost per therm, non energy benefits, and potential conservation credits. As stated earlier, the ETO has also included Solar measures in its portfolio, which have costs above the $1.00 These measures are include in the Trust's conservation resource stack as well as other efficiency measures determined to produce sufficient additional benefits to warrant their inclusion. Table 6-2 shows the group of residential measures and their technical applicability in Cascade's Oregon service territory based on the published study and metrics provided by the Energy Trust. Cascade's prior IRP noted that Oregon's technical potential, particularly for the residential market was likely high due to the significant decline in the demand forecast, primarily in the Company's Central Oregon service territory where new construction had fallen off significantly from the levels seen through 2008. This prediction appears to have been consistent with the revised data now offered by the ETO which indicates a reduction in technical potential by over an approximate 12 million therms. In addition to the ETO/Company screening limits, the Tables 6-2 and 6-3 also recognize the $.52 levelized cost limit recently instated by the OPUC for the natural gas programs offered by the Energy Trust. This screening would reduce conservation potential even more substantially as outlined below. That being said, the Energy Trust remains confident in the continued viability of its overall conservation potential and targets, nothing that the Trust's goals set the performance measure and that the measure is designed to annually index the Trust's budget and goals.

Table 6-2
RESIDENTIAL CONSERVATION MEASURES
TECHNICAL POTENTIAL BY 2031

OREGON		
Measure Description	**Gas Savings Therms**	**Levelized Cost ($/th)**
Gas Hi-eff Washer (New)	4,283	-$3.31
Gas MEF 2.0 Washer (New)	322	-$3.18
Gas Hi-eff Washer (Replace)	48,769	-$3.09
Gas ETO Dishwasher (New)	138	-$2.49
Gas ETO Dishwasher (Replace)	8,459	-$2.47
Gas MEF 2.0 Washer	1,660	-$2.12
Heating Upgrade (AFUE 95) (ZC)	9,721	-$0.70
Heating Upgrade (AFUE95) (ZB)	13,874	-$0.49
AFUE 92 to condensing combo hydrocoil, ZC (New)	24,026	$0.04
AFUE 92 to condensing combo hydrocoil, ZB (New)	21,650	$0.05
AFUE 95 Furnace, ZB (Replace)	220,493	$0.11
AFUE95 Furnace, ZC (Replace)	157,662	$0.16
Window, retro (U-.20), ZB (Retro)	387,586	$0.28
E* Insulation, Ducts, DHW, Lights (ZB) (New)	2,749,381	$0.28
E* Insulation, Ducts, DHW, Lights (ZC) (New)	2,015,061	$0.34
Window, retro (U=.35) ZB	694,784	$0.40
Upgrade Gas Hearth	5,988	$0.46
Window, retro (U=.20), ZC	233,490	$0.47
Near Net Zero (Gas ZB) (New)	1,310,649	$0.49
UM 1158 Performance Measure Cut-Off		
HRV, ZB (Retro)	196,522	$0.53
Window, retro (U=.35) ZC	499,806	$0.56
Tank Upgrade (50 gal gas)	77,004	$0.60
Near New Zero (Gas ZC) (New)	281,389	$0.62
HRV, ZC (Retro)	99,779	$0.76
Window (U=.20) (New)	68,085	$0.78
HRV, E* (Gas, ZB) (New)	394,464	$0.87
Solar Hot Water (50 Gals) w/Gas Backup (Retro)	71,316	$0.90
Solar Hot Water (50 Gals) w/Gas Backup (New)	54,168	$0.92
MF Corridor Ventilation (New)	6,460	$0.93
MF Corridor Ventilation (Retro)	20,656	$0.93
Window (U=.20) ZC (New)	56,676	$0.94
TOTAL TECHNICAL POTENTIAL		**9,734,321**
TECHNICAL POTENTIAL PER UM1158		**7,907,996**

Table 6-3 shows the list of measures and their technical applicability to Cascade's commercial market sector in Oregon.

Table 6-3
COMMERCIAL CONSERVATION MEASURES
TECHNICAL POTENTIAL BY 2031
OREGON

Measure Description	Gas Savings Therms	Levelized Cost ($/th)
EStar Steam Cooker (Replace)	43	-$1.85
EStar Steam Cooker (New)	19	-$1.85
EStar Commercial Clothes Washer (Retrofit)	11	$0.01
EStar Fryer (New)	7,614	$0.01
EStar Fryer (Replace)	21,560	$0.04
Estar Convection Oven (Replace)	1,318	$0.06
HW Boiler Tune (Retrofit)	688	$0.07
DHW Showerheads (Retrofit)	20,327	$0.12
Roof Insulation- Attic R0-30	38,423	$0.13
Hot Water Temperature Reset (Retrofit)	54,421	$0.14
Wall Insulation- Blown R-11 (Retrofit)	319,414	$0.18
Roof Insulation- Rigid R0-11 (Replace)	6,157	$0.19
Steam Balance (Retrofit)	18,700	$0.20
Wall Insulation- Spray On for Metal Buildings (Retrofit)	74,119	$0.21
DHW Wrap (Retrofit)	1,639	$0.21
Estar Convection Oven	698	$0.22
Heat Reclaim (Replace)	6,561	$0.24
Heat Reclaim (New)	5,213	$0.24
Roof Insulation- Blanket R0-19 (Retrofit)	102,150	$0.25
Roof Insulation- Blanket R0-30 (Retrofit)	107,174	$0.27
Roof Insulation- Rigid R0-22 (Replace)	6,988	$0.30
DCV (Retrofit)	113,718	$0.31
Vent Damper (Retrofit)	6,058	$0.31
Hot Food Holding Cabinet (New)	447	$0.41
SPC Hieff Boiler (Retrofit)	256	$0.41
Hot Food Holding Cabinet (Replace)	1,265	$0.42
Roof Insulation- Attic 11-30 (Retrofit)	87,293	$0.43
SPC Hieff Boiler (New)	987	$0.43
Roof Insulation – Rigid R11-22 (Replace)	18,127	$0.44
Ducts (Retrofit)	46,345	$0.51
SPC Cond Boiler Replace	741	$0.52
UM 1158 Performance Measure Cut-Off		
SPC Cond Boiler (New)	2,364	$0.53
Ozone Laundry Treatment	15,030	$0.57
Combo Hieff Boiler (New)	2,254	$0.59
DHW Recirc Controls (Retrofit)	34,677	$0.63
EStar Griddle (Retrofit)	334	$0.63
DHW Faucets (New)	120	$0.65
DHW Facuets (Retrofit)	1,355	$0.65

Measure Description	Gas Savings Therms	Levelized Cost ($/th)
Combo Hieff Boiler (Retrofit)	2,553	$0.66
Waste Water Heat Exchanger (Retrofit)	3,957	$0.67
EStar Griddle (New)	177	$0.69
DHW Condensing Tank (New)	7,227	$0.73
DHW Condensing Tank (Retrofit)	8,186	$0.73
Power Burner (Retrofit)	62,502	$0.74
Condensing Furnace (New)	10,353	$0.81
Roof Insulation – Roofcut 0-22 (Retrofit)	17	$0.83
Rooftop Condensing Burner (New)	11.949	$0.96
DHW Pipe Insulation (New)	179	$0.98
TOTAL TECHNICAL POTENTIAL	1,231,708	
TECHNICAL POTENTIAL PER UM1158	1,068,474	

Note on Industrial Potential:

The details behind the Company's technical industrial potential may require further analysis and refinement by the Energy Trust of Oregon and is unavailable at this time. However, according, to the ETO the current Cascade deployment scenario and relevant ramp rates correspond to 1,397,825 of therm savings for Energy Trust's Industrial program. This would correspond to a combined technical potential of 2,629,533 therms, or approximately 230k therms *less* than the achievable potential identified by the ETO later in this document. Both the industrial and commercial conservation screens reflect a good-faith assessment of technical potential offered by the ETO. The data is based on best-estimates supported by the most recent Stellar-Ecotope study and additional analysis by Energy Trust staff. The analysis of achievable commercial/industrial potential noted later in the IRP offers a more optimistic view of therm savings opportunities based on a ground-level assessment conducted by the Organization's field team. This accounts for the inverse correlation between technical and achievable potential as it relates to Cascade's Oregon service territory.

The 2011 Stellar Processes resource assessment identified 633,000 therms of cost-effective, achievable resource potential in Industrial sites in Cascade Natural Gas territory for the 20 year IRP window. This presents a discrepancy of 873,370 therms of savings between what ETO Planners believe they can realistically achieve and the total resource potential identified in the market. All Company conservation and DSM evaluation efforts in the State of Oregon are lead by the Energy Trust of Oregon. The Company has received the following details explaining the perceived increase in industrial potential, and has integrated this information into the IRP in good faith. The Energy Trust has acknowledged the discrepancy between the Stellar assessment and their own findings, and feels confident moving forward with the higher potential forecasts on the following grounds:

- The Stellar Processes resource assessment model did not classify customers in the exact way that that Energy Trust separates its customers into sectors, and so a distributional discrepancy is introduced.

- The Stellar Processes model assumes that those customers who are identified as Industrial have a gas load that is dominated by processes, with very little of the load going to space conditioning needs.

- Weatherization measures such as air abatement, retro-commissioning (RCx), and custom O&M have dominated historical (actual reportable) CNG Industrial sector savings (92% of total savings). This is not reflected in the Stellar Resource Assessment Industrial supply curve.

- Forecasts for potential savings from emerging technologies are also excluded from the supply curve. Recent study presented at ACEEE found the Northwest Power and Conservation Council's 5 year annual Power Plans to always find new resource available in the next years' Plans.

Energy Trust's understanding of industrial resource potential for CNG territory is evolving as the Organization learns more through actual deployment of Cascade's industrial program. The Trust perceives characterizing industrial resource potential as particularly difficult because of confidential information related to end use that varies widely by site. It is more problematic for Cascade because Cascade has only a few industrial sites of significant size and some with unusual loads. Increased experience with natural gas Conservation Efforts in CNGC's service territory will help refine the next resource assessment and has already helped refine the short term budget and action plan goals for Cascade industrial. For example, in 2011, the program achieved 87,000 therms and has set a 126,000 therm stretch goal for 2012. This is 100,000 therms more than was projected in the original deployment scenario taken directly from the dated Stellar model version referenced above.

Energy Trust program managers and planning staff remain confident in these higher goals and plan to continually improve resource planning tools going forward. Further updates to the resource supply curves will occur during future Cascade IRP processes, and will incorporate our increased understanding of Cascade's customers.

With the list of measures established, the next step was to determine the achievable potential and the 20-year DSM deployment scenario along with the associated annual utility costs to determine the level of funding that will be necessary to obtain those therm savings. The measures are grouped into categories (SF New construction, SF Retrofit, etc.) and deployment curves were developed.

It should be noted that the 2010 CNG IRP featured relatively ‘flat’ growth in therm savings from year-to-year after 2015. This is a result of simplifying assumptions employed in previous IRP planning processes, where it was assumed that a roughly 1/20th of the technical potential was available in each year (flat or zero ramp rate). More recently, Energy Trust has shifted away from this approach by utilizing information about the current state of technologies and programs, as well as expected changes in codes and standards to estimate more realistic ramp rates. This difference can be seen most prominently when comparing the ‘shape’ of the acquisition curves featured in each of the 2010 and 2011 IRP’s. The previous (2010) acquisition curve can be characterized by its relative flatness resulting from flat ramp rates, while the more recent (2011) acquisition curve has a more pronounced shape and definition as a consequence of using more detailed and granular data in the forecasting process.

Annual therm savings targets associated with the Low Income WAP have been included in the deployment curves as a separate line item as they are separate from the ETO’s targets. The Resource Assessment prepared by Stellar, includes the Conservation potential associated with the Low Income housing stock.

It should be noted that the figures shown for the residential and commercial sector represent the ETO’s best case “stretch” scenario annual therm savings targets for the planning horizon. In their annual budgeting process the ETO will typically develop their minimum target by applying 85% to their best case scenario to develop a range of therm savings to be achieved. For the 2012 period, the estimated range of annual therm savings for Cascade’s program would be between 347,996 (conservative goal) and 409,372 (stretch goal) and the estimated costs to achieve the stretch therm savings is currently estimated at $2,686,658.

Washington Conservation Study Results

As mentioned earlier, in 2008 the ETO approached Stellar to update the 2006 Oregon study. This Oregon update provided Cascade the opportunity to apply the relevant revisions seen in the Oregon assessment to the Washington study prepared in 2006. The most substantive change to the conservation assessment was the incorporation of the revised customer load growth forecast which significantly reduced the technical potential in the residential sector. In the 2008 Plan, it was estimated that the technical potential by 2030 for the residential sector was approximately 40 million therms, when screened at a levelized cost per therm of $.85. The impact of including the revised load forecast reduced the residential technical potential to 26 million. The complete list of measures and their applicability to Cascade’s Washington service territory are included in Appendix D-3 & D-4.

Since the completion of the 2008 IRP, the projected costs for natural gas have declined significantly and long-term prices are estimated to range between $5 to $6 over the planning horizon compared to the $8 to $10 forecasted in the 2008 IRP. This dramatic change is not only a result of the demand destruction that has occurred as a result of the global recession, but perhaps has been more heavily influenced by the new supply development technologies that are providing additional gas resources in North America. Shale gas from the Horn River Basin, Montney and Marcellus are likely to keep sufficient supplies in North America and some believe that shale gas could represent more than a third of the US production by the mid 2020s. This improvement to the long-term gas supply outlook is a stark contrast to the diminishing supply outlook that was prevalent during the development of the Company's 2008 IRP. As a result Cascade's historical approach of screening measures at a levelized cost of $.85 per therm must be modified with this IRP.

For this IRP, the company has grouped the residential measures into the following categories: Existing Shell Measures, New Construction Shell Measures, Domestic Water Heating (DWH), HVAC, Boiler to Combo System, and Appliances. Table 6-4 shows the group of residential measures and their technical applicability in Cascade's Washington service territory under the various levelized therm assumptions.

TABLE 6-4

WASHINGTON

RESIDENTIAL TECHNICAL POTENTIAL

	Screened at Levelized cost/therm of						
	<$0.65	**$0.70**	**$0.75**	**$0.85**	**$1.00**	**$1.50**	**>$2.00**
Existing Shell	3,585,461	3,585,461	3,585,461	3,585,461	3,585,461	3,585,461	3,585,461
New Construction Shell	5,776,721	5,776,721	5,776,721	7,920,357	9,365,736	9,365,736	9,365,736
HVAC	2,183,200	4,452,534	4,482,246	5,753,797	7,698,678	7,892,797	8,249,568
Water Heating (New/Existing)	155,904	155,904	155,904	1,135,937	1,135,937	1,878,664	1,878,664
Boiler to Combo System	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258
Appliances	1,060,550	1,065,143	1,065,143	1,065,143	1,065,143	1,065,143	1,065,143
Total	19,539,094	21,813,021	21,842,733	26,237,953	29,628,213	30,565,059	30,921,830

Table 6-5 shows the list of measures and their technical applicability to Cascade's commercial/industrial market sector. Changes to the Commercial segment are primarily the result of modification to the original Stellar estimates for potential heat reclaim measures and the applicability of cost effective window measures within Cascade's service territory.

Table 6-5
COMMERCIAL/INDUSTRIAL CONSERVATION MEASURES
TECHNICAL POTENTIAL BY 2030

WASHINGTON COMMERCIAL		
Measure Description	Gas Savings Therms	Levelized Cost ($/th)
Shell Measures	11,606,000	$0.29
O&M and Controls	1,245,000	$0.42
Cooking	2,646,000	$0.35
New Cooking	944,000	$0.35
New Heaters	975,000	$0.03
Replace Heaters	1,717,000	$0.31
New Boilers	673,000	$0.09
DHW Measures	839,000	$0.55
Replace Boiler	437,000	$0.53
New DHW Measures	405,000	$0.60
Refer Heat Reclaim	470,500	$0.80
New Refer Heat Reclaim	277,800	$0.80
Solar Pool Heat	29,400	$0.91
New Solar Pool Heat	6,400	$0.95
New Windows	231,250	$1.50
TOTAL COMMERCIAL	22,502,350	
		INDUSTRIAL
Boilers	442,000	$0.18
Shell Measures	294,000	$0.22
Unit Heater	176,000	$0.18
Process Hot Water	47,000	$0.10
Specialty Hot Water	16,000	-$0.81
TOTAL INDUSTRIAL	975,000	
TOTAL TECHNICAL POTENTIAL	23,477,350	

Based on the above technical potential, the Company has developed an estimate of the incremental conservation resources that can be acquired through 2030 on an annual basis. The company followed the ETO's approach used to develop the targets for Oregon, making modifications when necessary to recognize the differences associated with Cascade's Washington service territory.

It should be noted, that historically, the company has estimated the achievable potential and then estimated the annual targets based on a percentage of the achievable potential. The company modified its approach for this IRP, basing the annual estimates as a percentage of the technical potential rather than estimating the achievable potential and then developing the deployment curves. This modified approach results in achievable potential in the range of 65 to 85% of the technical potential over the 20 year planning horizon. Consistent with the development of the Oregon deployment curves, Cascade grouped the measures into categories (SF New construction, SF Retrofit, etc.) and deployment curves were developed utilizing the following key assumptions:

- In the area of Residential New Construction it was assumed that the technical potential would be spread equally over the 20 year planning horizon. Continuing from the deployment curves estimated in the 2008 Plan, it is assumed that participation levels will continue to ramp-up over the planning horizon, assuming 15% in 2011 and reaching a maximum participation of 75% by 2018.

- In the area of Residential replacement market, similar to the new construction sector, it was assumed that the technical potential would be spread equally over the 20 year planning horizon. Participation levels continue to ramp up, beginning with 30% in 2011 reaching maximum participation of 80% in 2017.

- Participation in the Residential Retrofit market was also assumed to continue to ramp-up over the 20 year planning horizon. Similar to the Oregon approach, it was assumed that over the 20 year horizon, that 80% of the technical potential would be realized through the residential retrofit program. Since the program is still relatively new (2010 is only the third year that retrofit measures have been included in the Company's residential program), participation levels were assumed to range from 3% in 2011reaching a maximum of 6% in 2017.

- In the Commercial retrofit market, similar to the residential retrofit market, it was assumed that participation levels would range from 3% in 2011 to a maximum of 6% in the 2017 period.

- In the Commercial/Industrial New Construction and Replacement markets, the technical potential was spread evenly over the 20 year planning horizon. On the new construction side, participation levels ramp-up from 15% in 2011 to 75% in 2018. In the replacement market, the ramp-up period begins at 20% in 2011 and increases 5% per year until reaching the maximum participation level of 75% in 2021.

- Annual therm savings targets associated with the Low Income Weatherization program have been included in the deployment curves as a separate line item. The Low Income Weatherization program is delivered by the Community Action agencies rather than the third party contactor who delivers the residential program and therefore separate targets are necessary. The Resource Assessment prepared by Stellar, includes the conservation potential associated with the Low Income housing stock.

- In developing the estimated costs to achieve the annual therm savings targets, it was assumed that commercial therm savings could be achieved at $4/therm while the residential sector would require approximately $6.50/therm.

Based on the assumptions outlined above, the estimated annual therm savings targets for the Washington Residential and Commercial/Industrial programs are shown in Table 6-6 on the following page. Similar to the ETO's approach, the figures shown for the residential and commercial sector represent Cascade's best case scenario for annual therm savings targets for the planning horizon.

Table 6-6 illustrates that Cascade anticipates its Low Income Weatherization program will be able to achieve a savings target of 40,000 in CY11, and 45,000 in CY12, then leveling off to a savings of 35,000 therms in CY13 and beyond. These numbers were determined by analyzing the capacity and limitations of the weatherization delivery network, as well as the potential for alternative avenues of therm savings during the years ahead. The company believes that the ARRA funding, which must be spent down by March 2012, will result in higher participation levels in 2011 and 2012. However, once the ARRA funding is spent, the company anticipates a return to the 35,000 level.

Conservation Summary

Based on the deployment curves developed for each state, Cascade estimates that the cumulative therm savings targets for the 2 Year Action Plan period (2011 – 2012) represents the displacement of approximately 44,869 residential customers' annual load requirements.

DSM Implementation Issues and Uncertainties

The amount of DSM potential identified for the plan relies on the best available information today about prices, efficiency, consumer behavior and preferences, and projects information 20 years into the future. As with other resources, DSM resource assessments depend heavily on energy load forecasts and projected growth rates with all of the associated uncertainties. Also similar to supply side resources, assessments of DSM potential are limited by what is currently available in the marketplace in terms of cost-effective technologies for improving energy efficiency. The impacts of new technologies and new energy efficiency codes and standards are difficult to accurately predict. This uncertainty is mitigated through the biennial updates of the IRP, which provide the opportunity to incorporate improvements in demand side technologies and programs.

However, somewhat unique to demand side resources are the utility's dependence on a large number of small purchases with each tied to the individual consumers' day-to-day purchasing and behavioral decisions. The utility attempts to influence these decisions through its programs, but the consumer is the ultimate decision maker regarding the purchase of DSM resources. Cascade's assessments of DSM make the best possible estimates of participation and costs, however, like any new program, the amounts are likely to vary from planning estimates.

Table 6-6

Estimated Achievable Therm Savings

	Washington			Oregon			Annual	Cumulative
	Residential	Comml/Ind	Low Inc.	Residentia*l	Comm/Ind*	Low Income	Savings	Therm Savings
2011	332,399	336,772	40,000	180,462	276,741	12,000	1,178,374	1,178,374
2012	396,845	356,237	45,000	122,224	287,149	15,000	1,222,455	2,400,829
2013	479,384	421,936	35,000	183,867	293,596	10,000	1,423,783	3,824,612
2014	581,840	487,636	35,000	184,321	239,056	10,000	1,537,853	5,362,465
2015	684,296	553,335	35,000	191,633	204,161	10,000	1,678,425	7,040,891
2016	786,752	619,035	35,000	205,236	204,161	10,000	1,860,184	8,901,075
2017	889,208	684,734	35,000	241,621	154,161	10,000	2,014,724	10,915,799
2018	907,301	730,969	35,000	458,437	129,161	10,000	2,270,868	13,186,667
2019	907,301	769,712	35,000	458,437	127,041	10,000	2,307,491	15,494,158
2020	907,301	808,454	35,000	458,437	121,056	10,000	2,340,248	17,834,406
2021	907,301	847,197	35,000	458,437	117,161	10,000	2,375,096	20,209,501
2022	907,301	885,939	35,000	458,437	114,161	10,000	2,410,838	22,620,339
2023	907,301	885,939	35,000	458,457	109,161	10,000	2,405,858	25,026,198
2024	907,301	885,939	35,000	458,437	104,161	10,000	2,400,838	27,427,036
2025	907,301	885,939	35,000	436,410	99,161	10,000	2,373,811	29,800,847
2026	907,301	885,939	35,000	414,383	94,161	10,000	2,346,784	32,147,631
2027	854,428	861,995	35,000	392,356	89,161	10,000	2,242,940	34,390,571
2028	801,555	838,051	35,000	348,301	86,661	10,000	2,119,568	36,510,139
2029	748,682	814,107	35,000	348,301	17,500	10,000	1,973,590	38,483,729
2030	722,245	802,135	35,000	348,301	15,233	10,000	1,932,914	40,416,643

* Achievable therm savings listed for the Residential and Commercial sectors of CNGC's Oregon Conservation Programs reflect the Stretch Target utilized by the Energy Trust of Oregon. The conservative targets utilized by the OPUC for assessing program performance for CY2012 are 244,077 Commercial/Industrial therms and 103,890 Residential for a total of 347,996 (rounded) therms.

It should be noted that yearly savings forecasts for the first five years of the deployment scenario (2012-2016) start at the sector level, where Energy Trust program managers employ a “bottom-up” approach to estimating savings for the immediate future. This process takes into account recent program volume at the measure level, projects ‘in-the-pipeline’, and the state of the current economic climate all within the context of the total achievable resource potential identified by Stellar Processes July 2011 Resource Assessment.

Annual savings forecasts and corresponding program growth rates for the *last* 15 years of the deployment do not feature as prominently in the inclusion of program manager’s predictions or historical savings trends. Instead, in these years more weight is placed on the ramp rates described in the Stellar Processes Deployment Scenario, which the ETO considers more indicative of broader economic trends and movements. These more general economic trends affecting the last 15 years of the deployment scenario can summarized as;

- Moderate growth in savings starting in 2016 as strength in overall economy begins to return.

- A peak in savings in 2019 due to an expected residential code upgrade in 2017 (see assumptions tab of Stellar Deployment Scenario 09-26-11)
- Savings falling gradually after 2019. (IRP projection does not include the adoption of new technologies in the forecast).

It has been agreed with ETO’s Board, the OPUC and the IOUs that a range of conservation estimates is necessary. The Stretch goal (see Table 6-6 and accompanying note) is to be used for estimating funding levels, and the Conservative goal (85% of Stretch) is a lower confidence bound which may be used by IRP planners. OPUC utilizes a target of 10% below the Conservative Goal as a performance metric for ETO. Therefore the figures in Table 6-6 reflect the best case or “stretch” scenario identified as achievable by the Energy Trust. Based on the significant updates to the Energy Trust’s 2011 Resource Assessment described earlier, the estimated achievable therm savings in Oregon for the 20 year period has been reduced by approximately 1.7 million therms since the last IRP. The conservative deployment scenario identified by ETO would reduce conservation potential by an additional approximate 1.4 million. As suggested earlier, changes in achievable resource potential can be attributed to changes in the baseline as a result of codes and standards, a reduction in the levelized cost threshold from $1.0/therm to $.75/therms for the purposes of assessing *long term* technical potential, and to revisions of load growth forecasts in the face of slow economic growth resulting from an ongoing recovery from the 2008 recession and housing market collapse. Achievable potential may be further weighed under the lens of currently the $.52 levelized cost limits for the combined Northwest Natural and Cascade Natural Gas conservation programs. As described earlier in this document, the OPUC mandated cost-effectiveness thresholds outlined in UM1158 are lower than the avoided cost limits identified by the Company and would reduce ETO conservation potential by an additional 163,234 therms in the commercial sector and 1.8 million therms in the residential sector. However, the

ETO does not believe that the performance measures, which have been designed across both NW Natural and CNGC, are used as the basis for measure cost-effectiveness; and that the budget and savings developed for Cascade are not directly influenced by the OPUC performance measure. The Trust will continue to develop the measure portfolio as traditionally done to acquire cost-effective savings within the constructs of its cost-effectiveness model approved by the OPUC.

As discussed above, actual implementation design, delivery, and market conditions will cause energy-efficiency program savings and costs to vary. Customer participation in a program is heavily influenced by the level of incentive paid by the utility or Energy Trust versus the cost to the customer. External infrastructure considerations must also be addressed, such as product availability to utility customers and an adequate network of contractors, retailers, and other trade allies to support a program. As new measures or expanded programs are developed and added to the current program mix, internal and external resources and capabilities need to grow accordingly and progress through a “learning curve”. For this reason, the company estimated conservation acquisition schedule increases over time. Additionally, revisions to the company’s existing programs may be necessary and will result in additional impacts on the company’s projected participation levels.

Other uncertainties relating to conservation resources include the risk of free riders, and lost opportunities. Free riders are those individuals that would have undertaken some form of conservation action even if a program had not existed. Measuring free rider impacts makes program evaluation difficult since it requires information on a hypothetical situation that, by definition, will never be observed. Lost opportunities assume that the opportunity to install cost-effective conservation measures occurs only once in the life of a home, office, or industrial plant. If all potential cost-effective conservation is not installed at one time, future DSM opportunities may be lost as a result. This is most likely true for commercial/industrial resources since it is unlikely that a business would close down or curtail operations for any period just to install conservation measures.

As discussed earlier, the potential for building code changes over the planning horizon represent another uncertainty that could impact the ability of the company to achieve its therm savings goals. When the code changes fully take effect, as they were recently in Oregon, both the Company’s programs and targets will need to be adjusted.

Potential carbon legislation is another area of uncertainty that Cascade continues to monitor closely. In Washington, specific requirements resulting from the Western Climate Initiative’s (WCI) Greenhouse Gas Cap and Trade design recommendation are still unknown. The recommendations though include reducing greenhouse gas emissions to 15% below 2005 levels by 2020. GHG measurements and monitoring began on January 1, 2010, for reporting in early 2011. The first phase of the cap-and-trade program is proposed to begin in 2012, covering emissions from electricity. The second phase would begin in 2015, when the program expands to include other fossil fuels, including natural gas.

At the Federal level, the traction for national legislation such as Kerry-Lieberman has decreased significantly and it is uncertain at this point the level of impact federal legislation will have as compared to the impacts of regional legislation.

Environmental Externalities

When evaluating DSM resources, the company also includes an evaluation of the impacts of environmental externalities. The impact of utilizing energy on the environment continues to be a subject of societal concern and debate. If there are impacts that cannot be repaired naturally within a reasonable period of time, damage cost to the environment occurs for which society will have to pay in some, as yet undetermined, form. The question of who pays, how much and when payment should be made, are complicated issues.

For many years, The Northwest Power and Conservation Council (NPCC) has utilized a 10% cost advantage for electric utilities acquiring conservation resources to realize the benefits of not using supply side resources. Such electric utility benefits include reduced fish and wildlife impacts, load stability, load predictability and improved air quality. As discussed in Section 7, when calculating the avoided cost figures, the company includes an incremental cost advantage for conservation resources. Historically, Cascade has included the 10% cost advantage for conservation resources which was consistent with Oregon's requirements for gas utilities for mandated residential weatherization programs. For this plan, the company developed a graduated scale ranging from 5% for short-term measures up to a 20% factor for longer-lived measures. The use of a graduated scale is an attempt to recognize non-quantifiable benefits associated with conservation, such as price certainty & a hedge value against future carbon costs.

The OPUC issued Order 93-965 (UM-424) to address how utilities should consider the impact of environmental externalities in planning for future energy resources that goes beyond the 10% cost advantage discussed above. In June 2008, the OPUC issued Order 08-338 (UM1302) which revised the IRP Guidelines associated with the analysis of environmental costs. The original guideline established in UM1056, required utilities to analyze the range of potential CO2 costs referenced in Order 93-965. Rather than providing a specific range of potential CO2 costs to be analyzed, the revised guideline requires the utility to construct a basecase portfolio that reflects what it considers to be the most likely regulatory compliance future for the various emissions. Additionally the guideline requires the utility to develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals and each scenario should include a time profile of CO2 costs.

Unlike electric utilities, environmental cost issues rarely impact a gas utility's supply-side resource choices. For example, Cascade cannot choose between coal-fired generation or wind energy sources to meet its load requirements. As a natural gas distribution company, the Company's only supply-side energy resource is natural gas. However, environmental externality costs do make a difference in the comparison between supply-side and demand-side resources.

At the time of this writing, specific details on the level of carbon allowances and how they may be allocated to the gas utilities under a cap and trade program are still unknown. Therefore, in an effort to create a more realistic and robust assumption with regard to potential Carbon legislation, Cascade utilized the most recent draft legislation, the Kerry-Lieberman proposal. Table 6-7 on the following page shows the updated analysis.

Other Demand Side Management

The general purpose of demand response is to help manage demand during periods of system stress. The term encompasses a number of activities including real time pricing, time of use rates, critical peak pricing, demand buyback, interruptible rates, and direct load controls. As discussed earlier, the majority of Cascade's annual throughput is for non-core transportation service customers who are responsible for securing their own pipeline capacity arrangements. Of the remaining industrial sales, approximately 25% of that load is being met through interruptible sales service. Interruptible service is attractive for large volume customers because of the lower distribution margin involved. As a result, the company believes that all customers that can manage their operations on interruptible service are currently served on an interruptible basis – leaving little opportunity to reduce peak loads through expanded interruptible service.

Table 6-7
Natural Gas Environmental Externality Cost Analysis
Updated with EIA's Estimated Emission Factors & Inflation

Emission		Emission (Lbs/Therm)	Cost ($/Lb)	Externality Adder ($/Therm)
SCENARIO 1				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$12/Ton	11.673	$0.006	$0.070
TOTAL				$0.080
SCENARIO 2				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$15/Ton	11.673	$0.008	$0.088
TOTAL				$0.098
SCENARIO 3				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$18/Ton	11.673	$0.009	$0.105
TOTAL				$0.115
SCENARIO 4				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$20/Ton	11.673	$0.010	$0.117
TOTAL				$0.127
SCENARIO 5				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$25/Ton	11.673	$0.013	$0.146
TOTAL				$0.156
SCENARIO 6				
NO2	$2500/Ton	0.008	$1.250	$0.010
CO2	$30/Ton	11.673	$0.015	$0.175
TOTAL				$0.185

General Assumptions:
Externality Adder reflects 1st year adder
Adder will increase annually by 3% and will be adjusted by the CPI, estimated to be 3.5%/year

Section 7

Resource Integration

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

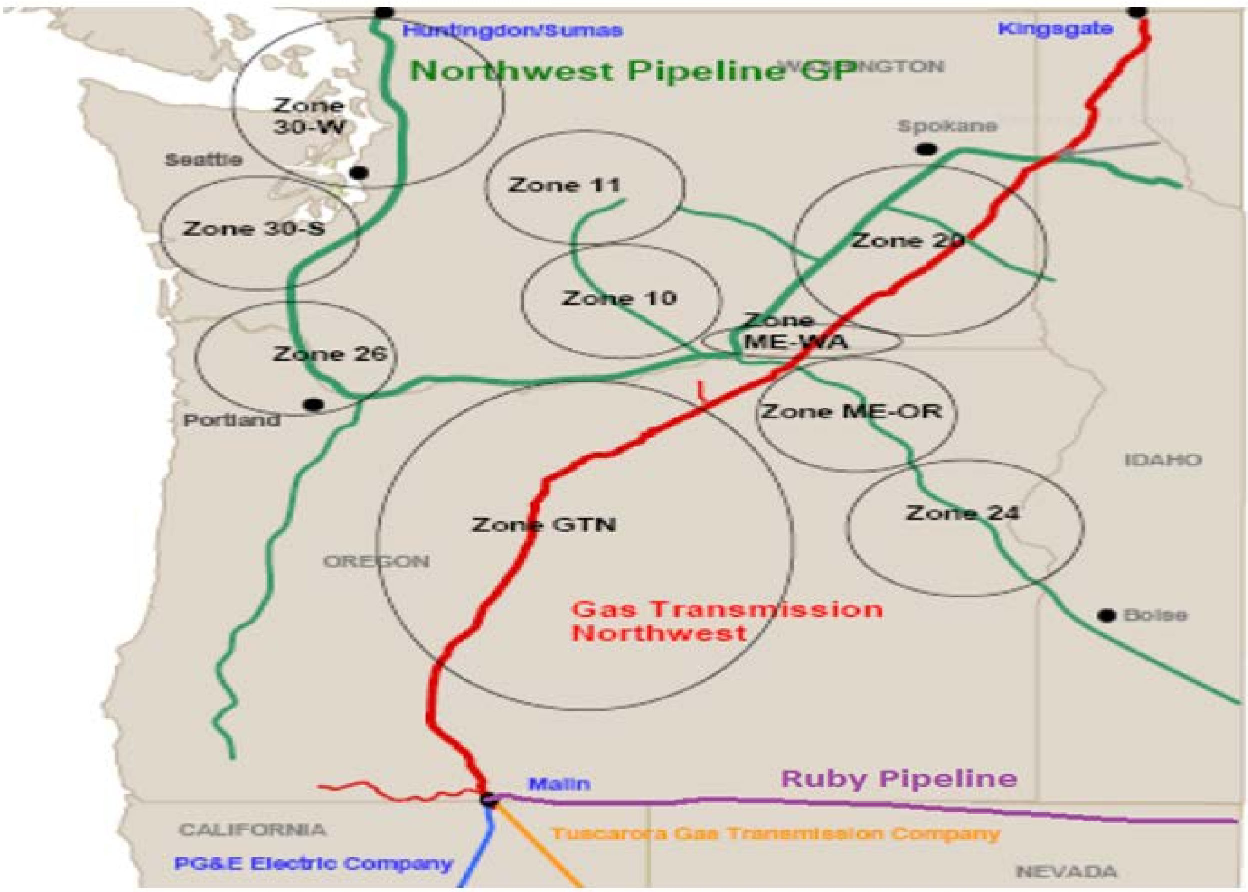
Resource Optimization Analysis Tools

SENDOUT™'s broad capabilities allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Cascade continued to model demand areas grouped by the various pipeline zones, a practice that began with the 2008 IRP. A copy of the network diagram is shown in Figure 7-A on the following page. These demand centers reflect on a daily basis, the aggregate 20 year load forecasts of Cascade's core market customers being served from either Northwest Pipeline GP (NWP) or Gas Transmission Northwest (GTN) interstate pipeline facilities. Individual transportation segments, storage, supply and demand side resources, both existing and potential, are targeted to these pipeline zones. 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, and storage inventory limitations and withdrawal and injection curve characteristics can be part of each resource's basic model inputs. The ability to model resources in this fashion allows SENDOUT™ to tailor its optimization within envisioned constraints and ensures that the model's optimal solution can work under anticipated operating conditions.

However, because SENDOUT™ utilizes a linear programming approach, its results are considered "deterministic". For example, the model knows the exact load and price for every day of the planning period based on the analyst's input and can therefore minimize costs in a way that would not be possible in the real world. 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, in 2006 Cascade purchased VectorGas™. VectorGas™ was an add-in product to the SENDOUT™ model that facilitates the ability to model gas price and load uncertainty (driven by weather) into the future. VectorGas™ utilizes a Monte Carlo approach in combination with the linear programming approach in SENDOUT™. The VectorGas™ functionality was integrated in the SENDOUT™ software with Version 12.5 which is the platform that Cascade prepared its integration analysis. The addition of the Monte-Carlo modeling capability provides additional 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.

FIGURE 7-A



Scenarios versus Simulations

Prior to discussing the modeling process, inputs, and ultimately the results of the analyses, a brief discussion of the term scenarios versus simulations is necessary. As stated earlier, SENDOUT™ relies on a series of inputs or assumptions and then solves for the least cost solution based on the information provided to the model. Each group of assumptions is considered a scenario. For example, the company models medium load growth under average weather conditions where the assumed daily weather pattern is input into the SENDOUT™ model. The company also runs scenarios utilizing the low and high growth forecasts and historically has run several different price assumption scenarios. The results of each of these scenarios provide an answer or a least cost solution, which the optimization model has solved based on its perfect knowledge. Historically, this has provided the range of expected outcomes. However, with the addition of the Monte-Carlo functionality, the Company can now run simulations to determine if the scenario results are reasonable and to provide an expected range of results based on a statistical analysis.

Table 7-1 provides the list of scenarios included in this IRP and their key assumptions. To assess the impacts due to variations due in pricing and weather the company ran Monte-

Carlo simulations on the Basecase scenario. The Company utilized the Basecase scenario as it represents the scenario Cascade considers most likely to be experienced over the planning horizon.

The basecase (Medium Load Growth, Medium Gas Price Forecast, Average weather with Peak Event) includes existing supply contracts, incremental supplies (peaking, annual, seasonal and citygate) from various receipt points (AECO, Rockies, Sumas, Station 2 and Malin). Other incremental supplies also include propane and satellite LNG (behind citygate). The basecase includes current upstream pipeline transport capacity, as well as Ruby and incremental NWP and GTN capacity. We also included Cascade's current Jackson Prairie storage accounts, our Plymouth LNG account, as well as the potential to obtain a third party's Jackson Prairie account or Mist storage.

In addition to the 200 draws, the Company prepared several sensitivity scenarios to test the resource selections when the baseline conditions were changed. Table 7-2 below describes those sensitivity scenarios.

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

TABLE 7-1
SUMMARY OF PORTFOLIO ANALYSIS AND RESOURCE ALTERNATI VES

Scenario Name	Key Elements in SENDOUT Scenario
All in Case	Medium Load Growth, Medium Gas Price Forecast, Average weather with Peak Event. Includes existing supply contracts, incremental supplies (peaking, annual, seasonal and citygate) from various receipt points (AECO, Rockies, Sumas, Station 2, Malin, as well as behind the citygate (satellite LNG)). Incremental supplies also include propane, satellite LNG (behind citygate), imported LNG (Jordan Cove, Bradwood Landing), current upstream pipeline transport capacity, as well as proposed pipelines and extensions (Blue Bridge, Ruby, Pacific Connector, and Palomar). We also included Cascade's current Jackson Prairie storage accounts, our Plymouth LNG account, as well as the potential to obtain a third party's Jackson Prairie account, as well as AECO and Mist storage. Almost any alternative that can be reasonably considered is included.
Limited Canadian Imports	Model contains all the elements of the Basecase, but incremental Annual AECO and seasonal Sumas resources will be unavailable to the model. Additionally, annual Sumas max is lowered from 100,000 to 50,000 dths. The intent is to mimic possible Canadian LNG exports to Asia.
Blue Bridge (NWP Expansion) With GTN backhaul and Palomar	Model contains all the elements of the Basecase, utilize transporation by others (TBO) between NWP and Palomar to reach "Blue Bridge" or continue on to Central Oregon down GTN
No Rockies price advantage	Model contains all the elements of the Basecase; however, all potential incremental resources are priced at NYMEX flat with no basis adder. In other words, incremental AECO, Sumas and Rockies all have the same price. This scenario allowed testing of inputs as transport costs were the variable.
Ruby Pipeline	Model contains all the elements of the Basecase; however, Ruby Pipeline is added as an additional resource. For modeling purposes we assume the $0.95 rate (the max rate identified in their tariff). The model is set up so that Ruby becomes an option to move Rockies gas to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates, likely in Central Oregon, although it is possible to move the gas to Stanfield for transport on NWP. See Table 7-5 to see additional scenarios that were run for Ruby Pipeline and Incremental GTN northbound primary service.
Pacific Connector	Model contains all the elements of the Basecase; however, Pacific Connector is added as an additional resource. In addition, we will add incremental LNG (Jordan Cove) as a potential resource. For modeling purposes we started with Pacific Connector transport priced at approximately 3 times the current NWP rate. The model is set up so that Pacific Connector becomes an option to move imported LNG to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates.
Original Palomar or a Cross Cascade Pipeline	Model contains all the elements of the Basecase; however, Palomar Pipeline is added as an additional resource. In addition, we will add incremental LNG (Bradwood Landing) as a resource. We will use the max rate identified in their tariff. The model is set up so that Palomar becomes an option to move imported LNG to GTN, where it would take incremental GTN capacity (backhaul) to move to Cascade's citygates. We also will look to see about using Palomar to backhaul to NWP near Portland and move supplies up BlueBridge or continue along NWP.
AECO Storage	Model contains all the elements of the Basecase; however, AECO storage is added as a resource. The inventory is set at 300,000 dths, with daily withdrawal rights of 10,000 dths a day. This storage will be setup like the existing Jackson Prairie to be 100% full at the start of each heating season. The model is set up so that Canadian withdrawals can use incremental GTN capacity

TABLE 7-2
Sensititives Analyses

Scenario Name	Key Assumptions
High Growth	Strong Economic Growth result in High Load growth, Average Weather, Medium Gas Prices
Low Growth	Economic Conditions result in Low Load growth, Average Weather, Medium Gas Prices
Environmental Externalities Scenario 1	Medium Load Growth, Average Weather, Assumes Carbon Cost Adder Implemented in 2016 for CO2 emissions at $15/ton with adder increasing annually by 3% plus CPI (EE Case #2)
Environmental Externalities Scenario 2	Medium Load Growth, Average Weather, Assumes Carbon Cost Adder would be applied in 2016 for emissions at $20/ton with adder increasing annually by 3% plus CPI (EE Case #4)
Environmental Externalities Scenario 3	Medium Load Growth, Average Weather, Assumes Carbon Cost Adder would be applied in 2016 for emissions at $30/ton with adder increasing annually by 3% plus CPI (EE Case #6)

Key Inputs

Demand Forecast Items & Weather Assumptions

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. The company develops usage factors for each of the zones shown on Figure 7-A; this includes nine demand centers on NWP and one on GTN which is utilized to meet Cascade's Central Oregon load. In order to develop the temperature sensitive usage factors on a zone by zone basis, the company reviewed pipeline deliveries for the 2004 through 2009 period and developed monthly use per customer per degree day factors. The annual customer growth rates from the low, medium and high forecasts discussed in Section 3 were developed for each of the NWP zones and were applied to 2009 monthly core customer counts. Weather patterns for each of the zones were developed based on 5 distinct weather areas. The weather areas and their applicability to each of the zones are shown in Appendix B-1.

Prior to the 2007 IRP, the company had developed daily temperature patterns to estimate the impact of weather ranging from warmer than normal to design conditions, with the expected portfolio being one with average weather. The average weather pattern historically had been based on the 20 year average excluding the high/low annual degree day totals to develop an annual total for each area. These totals were then allocated to the daily readings based on the 90/91 winter pattern since that was the most recent year in the company's weather history with a peak day reading of 61 DDs. However, with the ability to run Monte-Carlo simulations, the company modified its approach and developed its "average" weather pattern based on the company's 60+ year weather history, and the expected degree days for each month. The average pattern for each area was approached on a month-by-month expected value and then the degree days were allocated within the month based on the past years' average daily distribution. Since a peak event can occur in an otherwise normal weather year, the average weather scenario includes one 3-day peak event, which includes a design day reading of 61 degree days system wide.

Demand Side Alternatives

For purposes of this IRP, the Company has utilized the annual achievable potential schedule shown on Table 6-6 in Section 6 as an input to the optimization model. Because the company models demand by individual zone, conservation has been treated as a "must-take" supply alternative available at the pipeline citygate level. This approach allows the conservation resource to displace supply and pipeline transportation resources that would otherwise be necessary to meet demand requirements. For purposes of modeling, 80% of the identified Oregon Conservation resources are assumed to occur on the GTN pipeline with the remaining 20% occurring on Northwest pipeline. Washington conservation was modeled as a must-take resource at the NWP citygate. Because the acquisition of DSM is dependent upon a number of small purchases, determining which pipeline zones will procure the most conservation at this point is still premature. In future planning cycles, the company will continue to review the results of the participation levels and determine if more detailed assumptions on conservation acquisition can be modeled. Under the basecase scenario the company has assumed that conservation resources could be purchased, on a levelized cost per therm basis of $6. The cost per therm figure of $6 is an estimate of the combined Total Resource Cost for all measures included in the program, including program delivery and administration costs.

Supply Side Resource Alternatives

For modeling purposes, supply side alternatives are grouped into one of three categories: gas supply, storage facilities, or pipeline transportation. As discussed in Section 5, some of the supply alternatives include one or more of these categories. For example, a gas supply resource may be delivered at Cascade's citygate, essentially reducing the requirement for firm pipeline capacity. A satellite LNG facility (whether trucked in or liquefied on site) located within Cascade's distribution system can reduce the need for pipeline capacity on a peak day as the supplies will be available to be directly flowed into Cascade's local system. The following table provides a high level summary of the resource alternatives considered over the planning horizon.

Table 7-3
Supply Side Alternatives Modeled

Resource	Scenario Considered
Conventional Gas Supply Contracts with annual, seasonal or winter only characteristics delivered to Northwest Pipeline & GTN Systems	All
Conventional Gas Supply Peaking Contracts Delivered to Northwest Pipeline & GTN Systems	All
Gas Supply Peaking Contract delivered to Cascade's citygates	All
LNG Import Supplies Delivered to Northwest Pipeline System	All
Satellite LNG Storage within Cascade's distribution sytem	All
Additional Pipeline Capacity secured through medium--long term capacity agreements	All

Natural Gas Price Forecast

Price volatility has become an on-going factor in the natural gas industry since 2005. Prices in the natural gas market continued to be volatile through 2008 (upwards to $13 per dth), but have since dropped considerably (currently around $4). As discussed in Section 5, natural gas prices will continue to be influenced by demand, oil price volatility, the global economy, electric generation, new extraction technologies, hurricanes and other weather activity. As a result, it is impossible to accurately estimate what future natural gas prices will be over the planning horizon. However, Cascade has considered price forecasts from several sources, such as Wood Mackenzie, Energy Information Administration, the Financial Forecast Center's forecast, as well as our observations of the market to develop our low, base and high price forecast. As mentioned earlier, details of the company's price forecast can be found in Appendix E.

The Company compared the Monte-Carlo price simulation results to the low, base and high forecasts and found that the 200 draws captured the same range of pricing outlined in the forecasts shown in the Appendix. Therefore, individual deterministic runs under the low and high price forecast were not run.

Integration Results and Key Findings

As described earlier in this section, Cascade performed several different scenarios and the results are summarized below. However, it should be noted that the results of these analyses should be considered broadly. Like all analyses, the results of the resource optimization models are dependent upon the input assumptions provided. Scenario and Monte-Carlo analysis help by providing information on the ranges of input assumptions. Whether Cascade eventually secures these particular resources, acquires ones of comparable size and characteristics, or decides on an alternative approach is subject to ongoing resource investigation and evaluation activities. Specific resources made available to the model at this time may or may not be physically available at the time they are needed or economically attractive in comparison to alternatives that may become available in the future. Therefore, prior to securing any of these resources, additional analyses of the specific resource must be completed.

The results of the various scenarios are fairly consistent and reveal the following general trends:

- The basecase results indicate energy efficiency programs with a levelized cost of 70 cents per therm or less are cost-effective over the planning horizon, with the price uncertainty analysis indicating that the levelized costs will likely range between 64 to 80 cents per therm. However, if a carbon cost adder was established during the planning horizon similar to those described in Section 6, the cost-effectiveness limits could increase between 8 to 16 cents depending upon the level of the carbon adder and the timing of its implementation. Cascade used the conservation curves based on a levelized cost of 70 cents per therm in developing its conservation deployment curves.

- Even with energy efficiency programs, Cascade will need to acquire additional capacity resources to meet anticipated peak day requirements, due to Cascade's continued growth in its residential and commercial customer base. Several of Cascade's existing transportation agreements will expire over the next several years. In most cases, Cascade has the unilateral right to extend or cancel the expiring contracts upon one year's notice. As a result, the company will have the opportunity to review alternatives to extend or replace those contracts.

- Since Williams announced that the Blue Bridge I-5 corridor project had been shelved, and with uncertainty surrounding the likelihood of Palomar being built, Ruby Pipeline emerged as a more feasible transportation resource to bring Rockies supplies to Central Oregon, via Malin and backhaul service on GTN. Ruby transport could take the form of a long-term transportation agreement and/or via a capacity release from a current Ruby shipper.

- Another alternative to acquiring Rockies supplies, without becoming a shipper on Ruby, would be to enter into supply arrangements with parties at Malin, or a possible exchange arrangement involving Stanfield.

- Satellite LNG/Peak shaving facilities located within Cascade's distribution system (for example Zones 10 and 11—the Wenatchee lateral) may also be an attractive alternative to incremental pipeline capacity in areas where physical limitations at the gate stations would result in even higher costs associated with a pipeline solution. There may be additional advantages to such a strategy to the extent a facility could be strategically located on a portion of the distribution system that will eliminate or reduce distribution system constraints.

- The initially proposed Pacific Northwest LNG import facilities would require incremental transportation via NWP or GTN. The Company has insufficient information available as to the likelihood and costs associated with acquiring additional transport capability to move supplies from the proposed Northwest facilities to Cascade's distribution system. More to the point, based on the shale boom, recent FERC filings and increasing demand in Asia, it looks like LNG will become an export from the Pacific Northwest as opposed to importing.

- We considered the impact of possible reductions in exports of gas supplies physically produced in British Columbia and Alberta, by limiting the amount of physical Canadian supplies that could be exported via existing infrastructure at Station 2, Sumas or AECO to 80%. Under this scenario, the model chose to increase the amount of imported Rockies gas via either Ruby/Malin transaction or Malin/Stanfield exchange. Given the proliferation of shale gas, we do not see access to Canadian gas being a problem—gas will be available—however, we will be competing with many parties and consequently, may experience potential volatility and price spikes.

- Although it has since declared bankruptcy, at the time of the initial development of this IRP a scenario was developed to move LNG from the proposed Bradwood Landing facility, connecting to Palomar Pipeline and ultimately delivered to Madras, OR where it would flow on incremental GTN capacity to serve Central OR. At this time, it is unlikely an import facility at Warrenton will be put into service.

- Although the facility filed in September 2011 to become an exporter, at the time that IRP scenarios were first set during the summer of 2011, the company evaluated transporting LNG from Jordon Cove via Pacific Connector Pipeline and then backhauling supplies on GTN to serve Central OR. Similar to the Bradwood Landing example discussed above, this scenario is complicated because it is unclear whether GTN will provide firm backhaul capability. It appears the infrastructure required to provide that firm backhaul service on GTN coupled with the transport from the facility makes this scenario appear to be undesirable, given other potential options.

- Incremental Jackson Prairie storage was also selected by the model. The company will continue to evaluate potential options to acquire more on system storage capabilities.

- 20 year portfolio costs on a Net Present Value (NPV) basis, are expected to range between $2,448,210,000 to $3,216,376,000 for the planning period, with an average cost per therm ranging between $.354 and $.447.

Table 7-4 on the following page summarizes the results from each of the modeling scenarios.

Table 7-4
SUMMARY OF PORTFOLIO ANALYSIS RESULTS

SENDOUT ™ RUN	Results
All Resources	The all resource run allows the company to determine the likely basecase although the company still runs sensitivities on the various pipeline projects. Currently Ruby accompanied with incremental GTN capacity seems to be selected. None of the initial LNG facilities were selected unless extremely discounted (e.g. reservation rates at less than $0.05) Satellite LNG facilities located within Cascade's distribution system may also be an attractive alternative to incremental pipeline capacity in areas where physical limitations at the gate stations would result in even higher costs associated with a pipeline solution. There may be additional advantages to such a strategy to the extent a facility could be strategically located on a portion of the distribution system that will eliminate or reduce distribution system constraints.
Limited Canadian Imports	• Not likely—will be exporter • Natural gas is expected to be abundant for the foreseeable future • The other storage options may provide some other sourcing possibilities.
Blue Bridge With GTN backhaul and Palomar	• Rate stacking • Basis parity would mean this provides transportation diversity as opposed to supply diversity • GTN backhaul offering • Potential bottleneck at Stanfield and/or Malin
No Rockies price advantage	In this run, the model chose to increase interest in acquiring Ruby. We continue to run numerous sensitivities with varying levels of restrictions in order to see the impact to the portfolio. See Table 7-5 for more Ruby scenarios.
Ruby Pipeline	• Rate stacking (GTN and Ruby); although discounts increased electability volumes • Basis parity would mean this provides transportation diversity as opposed to supply diversity • GTN backhaul offering
Pacific Connector	• Unknown if facility will ever get built • GTN backhaul offering • Rate stacking • Potential bottleneck at Stanfield and/or Malin
Palomar	• Unknown if infrastructure will ever get built • GTN backhaul offering • NWP additional facilities needed? • Potential bottleneck at Washougal, Stanfield and/or Malin
AECO Storage	• Competition with Alberta for re-fill volumes • Rate stacking

Modeling for Ruby Pipeline and Incremental GTN northbound firm service

Given the likelihood of at least the Ruby capacity becoming part of the portfolio sometime in 2012, we are providing some additional information in this IRP regarding these two potential alternative resources. Utilizing the SENDOUT™ resource optimization model, several scenarios were run to test the viability of acquiring Ruby capacity either based on their proposal, or through a third party. Incremental and corresponding GTN Malin north capacity was also modeled (a summary of the RMIX results is attached). Basin prices in the model over the 20 year planning horizon have Rockies trading at a slight discount to AECO, Malin and Sumas ($0.06 - $0.15).

Regardless of the scenarios modeled, SENDOUT™ consistently selected Ruby capacity in a range of 10,000 to approximately 19,000 dths/day. A recap of some of the scenarios run and the results follows:

Table 7-5
Summary of SENDOUT™ results for Ruby and Incremental GTN northbound firm service

SCENARIO	RESULTS	ADDITIONAL COMMENTS
RUBY DISCOUNTED PORPOSAL WITHOUT DISCOUNTED GTN BACKHAUL Ruby Xport: 25 years, Seasonal (Nov-Mar),$0.75 reservation, $0.01 commodity, 1.5% Fuel, no limit MDQ, allow resizing every year after Oct13: GTN backhaul at current recourse rate (approx $0.26)	SENDOUT™ selected 17.26 MDth/day Nov12-Oct13 and 17 MDth of GTN backhaul	This is the Ruby deal without taking into account discounted GTN backhaul, or comparisons to a shorter term Ruby capacity release.
RUBY PROPOSAL AT RECOURSE VS RUBY DISCOUNTED CAP REL Ruby Xport: 25 years, Seasonal (Nov-Mar),$0.95 reservation (recourse rate), $0.01 commodity, 1.5% Fuel, no limit on MDQ, allow resizing every year after Oct13 Vs Ruby Cap Release: 10 years, Annual release from 3rd party,$0.69(discounted) reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ	SENDOUT™ selected 10 MDth of 3rd party capacity release and 7.45MDth/d of the Ruby proposal and 17.19 MDth of GTN backhaul	Even at the recourse rate, SENDOUT™ selects a substantial portion of Ruby on a seasonal basis
Ruby Xport: 25 years, Seasonal (Nov-Mar),$0.75 reservation, $0.01 commodity, 1.5% Fuel, no limit on MDQ, allow resizing every year after Oct13 Vs: Ruby Cap Release: 10 years, Annual release from 3rd party,$0.75 reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ	SENDOUT™ selected 10 MDth of 3rd party capacity release and 7.26 MDth/d of the Ruby proposal and 17 MDth of GTN backhaul	

25 YR RUBY DISCOUNTED PROPOSAL VS 25 YR ANNUAL CAP REL VS 10 YR CAP REL Ruby Xport: 25 years, Seasonal (Nov-Mar),$0.75 reservation, $0.01 commodity, 1.5% Fuel, no limit on MDQ, allow resizing every year after Oct13 vs. Ruby Cap Release Annual: 25 years, Annual release from 3rd party,$0.75 reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ vs. Ruby Cap Release: 10 years, Annual release from 3rd party,$0.75 reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ	SENDOUT™ selected 10 MDth of 3rd party capacity release and 7.45MDth/d of the Ruby proposal and 17.19 MDth of GTN backhaul	
RUBY DISOUNTED PROPOSAL VS STEEP DISCOUNT RUBY CAP REL Ruby Xport: 25 years, Seasonal (Nov-Mar),$0.75 reservation, $0.01 commodity, 1.5% Fuel, no limit on MDQ, allow resizing every year after Oct13 Vs Ruby Cap Release: 10 years, Annual release from 3rd party,$0.57(40% discount of recourse rate of $0.95) reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ	SENDOUT™ selected 10 MDth of 3rd party capacity release and 7.26MDth/d of the Ruby proposal and 17 MDth of GTN backhaul	
RUBY DISCOUNTED PROPSAL WITH DISCOUNTED GTN VS STEEP DISCOUNT RUBY CAP RELEASE Ruby Xport: 25 years, Seasonal (Nov-Mar), $0.75 reservation, less $0.06 through March 2017 to represent the 80% discounted GTN northbound capacity that Ruby has offered to acquire and then re-release to Cascade for approximately 4 years. Per Ruby email 11/15/2011: ***If the delivery point is Stanfield, assume a ~ $0.20 rate (depends on points selected), with a 10,000 Dthd MDQ. Therefore $ 3,200,000 / $0.20 /10,000 = 1,600 days of FTSA. 1,600 / 365= 4.38 years of discounted GTN capacity***, model assumes GTN northbound returns to recourse levels after 2017, $0.01 commodity, 1.5% Fuel, MDQ limited to 10 MDTh/day vs. Ruby Cap Release: 10 years, Annual release from 3rd party,$0.57(40% discount of recourse rate of $0.95) reservation, $0.01 commodity, 1.5% Fuel, 10,000 dth MDQ	SENDOUT™ selected 8.84 MDth of 3rd party capacity release and 10MDth/d of the Ruby proposal and 18.56 MDth of GTN backhaul	This scenario mimics the current Ruby proposal against a steeply discounted yearly capacity release from a 3rd party.

Peak Day Planning Results

Figures 7-B-1 through 7-B-3 show the projected peak day requirements compared to the Company's existing capacity resources under the medium load growth forecast. This same comparison was completed for both the high and low load growth forecasts and results of the zone by zone analysis are included in Appendix F. Under all growth scenarios, the company will require incremental peak day delivery in order to meet Cascade's anticipated peak loads located on the Northwest Pipeline system. This shortfall results from the expiration of a leased storage agreement that ended in April 2007. As discussed in Section 5, the company has acquired incremental Jackson Prairie storage inventory and withdrawal capability through the participation in the JP expansion open season, which took place during early 2006. The Company has also entered into a companion transportation agreement with Northwest Pipeline for the transportation to deliver the stored supplies under this agreement to Cascade's service territory. In the interim, Cascade will meet its peak day requirements with citygate peaking resources, acquiring vintage transportation returned to the pipeline, and where operational feasible, re-aligning existing contract delivery rights form areas where we project excess capacity to areas where we forecast potential shortfalls.

Figure 7-B-1

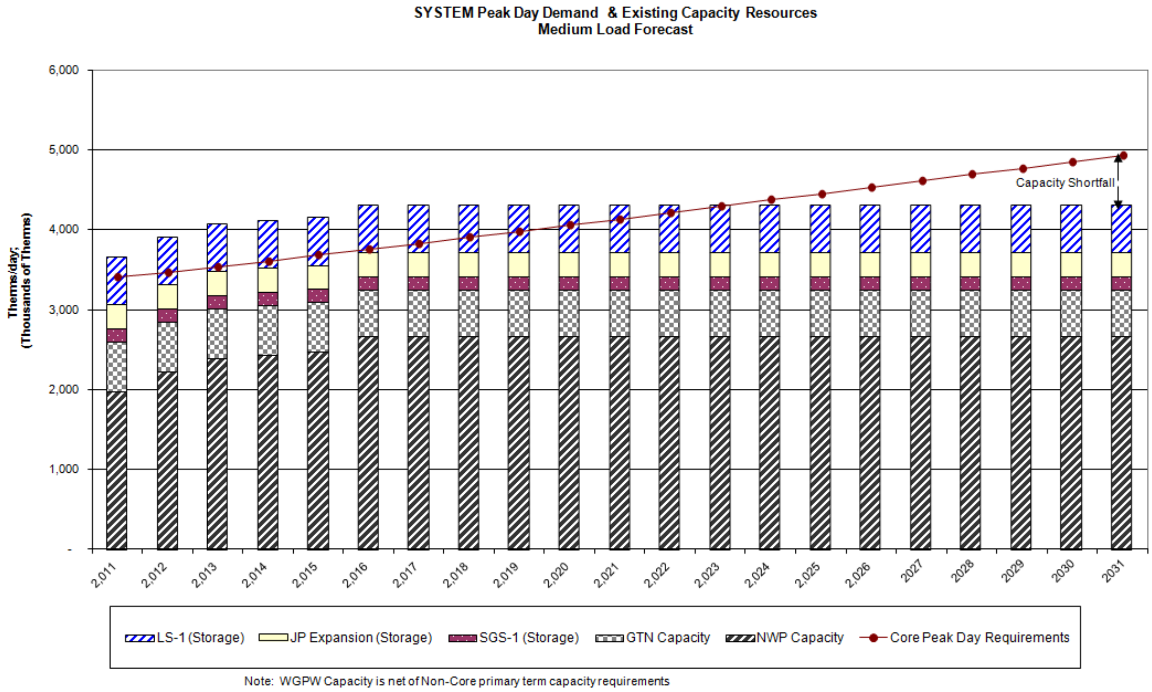


Figure 7-B-2

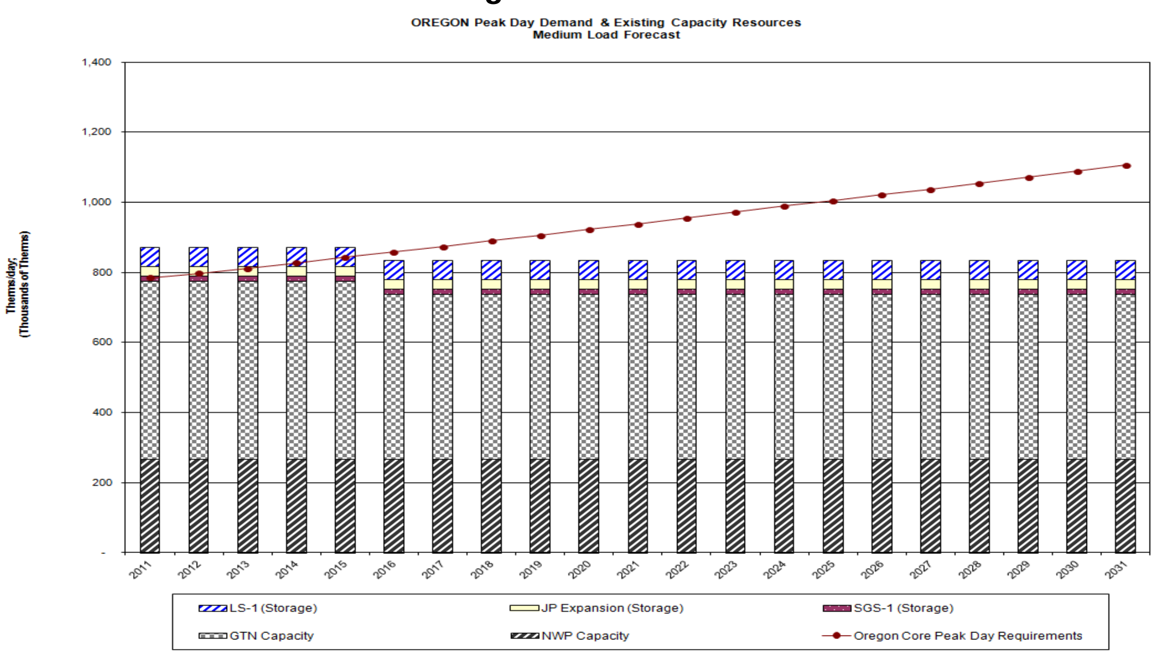
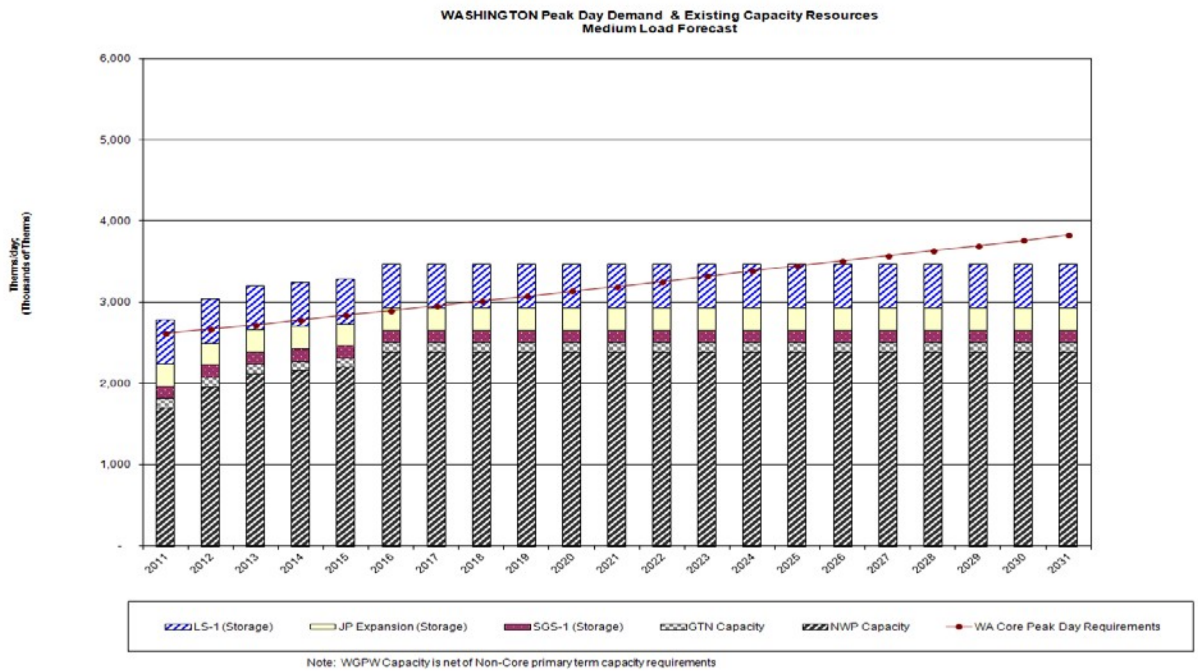


Figure 7-B-3



For modeling purposes, the company included several capacity alternatives to meet peak planning needs. Based on the analysis, peak day requirements will be met through a blend of resources. For purposes of the graphical depiction, the company has shown the incremental conservation resources as a capacity resource. As shown in Figures 7-C-1 through 7-C-3, incremental pipeline capacity on NWP, GTN, along with a combination of citygate peaking, Ruby and satellite LNG alternatives will be used to meet growing peak requirements.

FIGURE 7-C-1

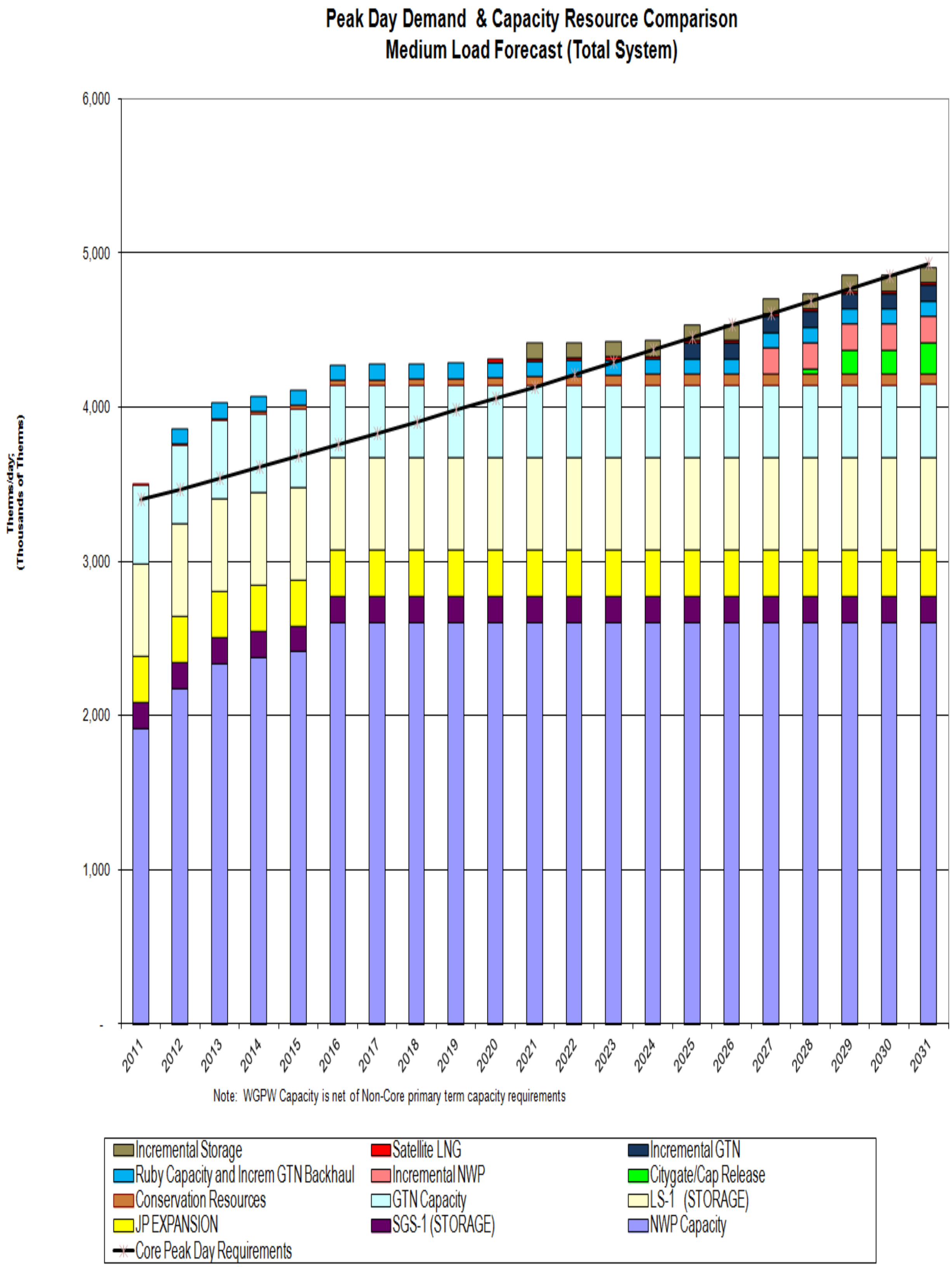

Peak Day Demand & Capacity Resource Comparison
Medium Load Forecast (Total System)
Therms/day (Thousands of Therms)
6,000
5,000
4,000
3,000
2,000
1,000
-
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Note: WGPW Capacity is net of Non-Core primary term capacity requirements
Incremental Storage
Satellite LNG
Incremental GTN
Ruby Capacity and Increm GTN Backhaul
Incremental NWP
Citygate/Cap Release
Conservation Resources
GTN Capacity
LS-1 (STORAGE)
JP EXPANSION
SGS-1 (STORAGE)
NWP Capacity
Core Peak Day Requirements

FIGURE 7-C-2

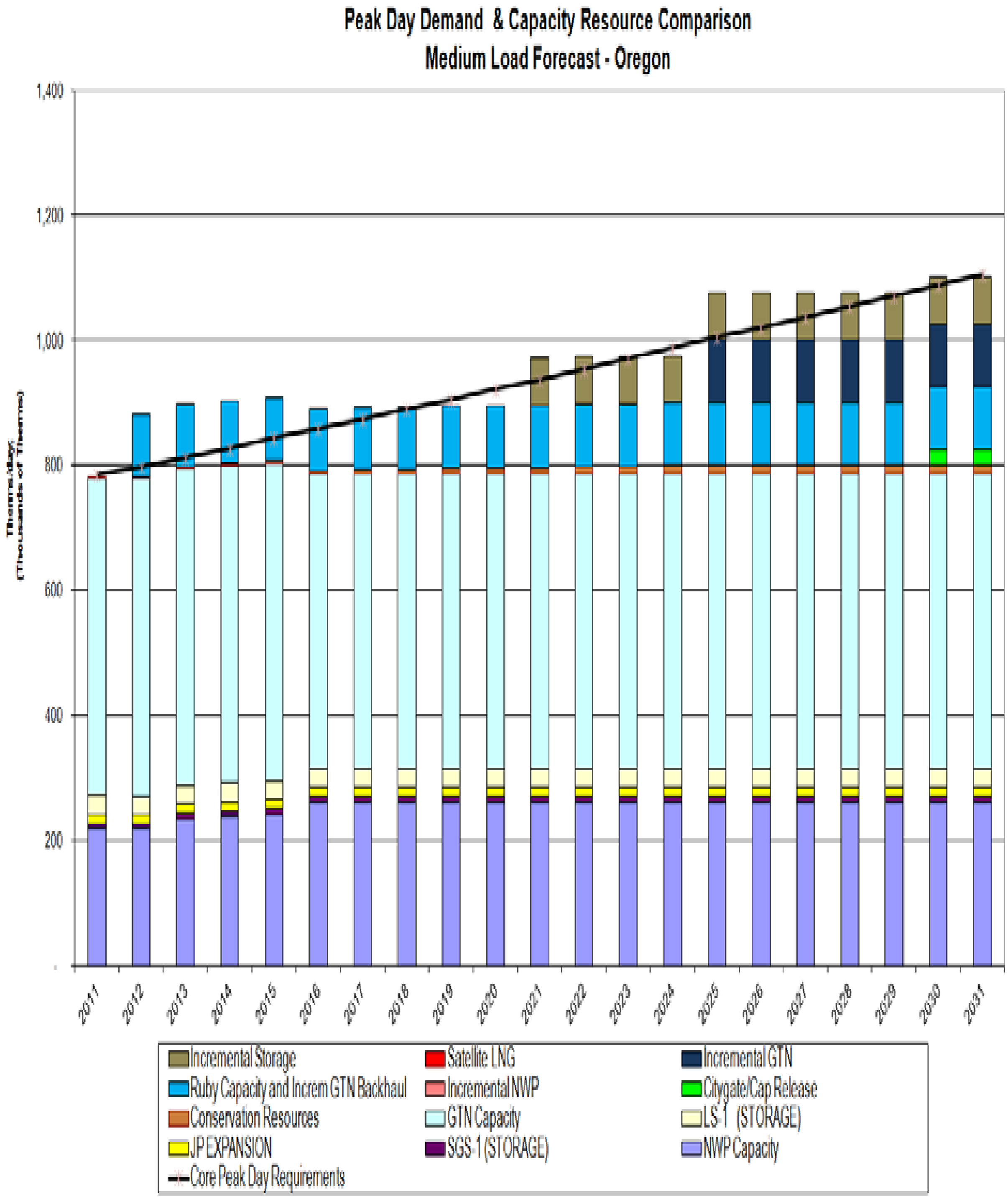
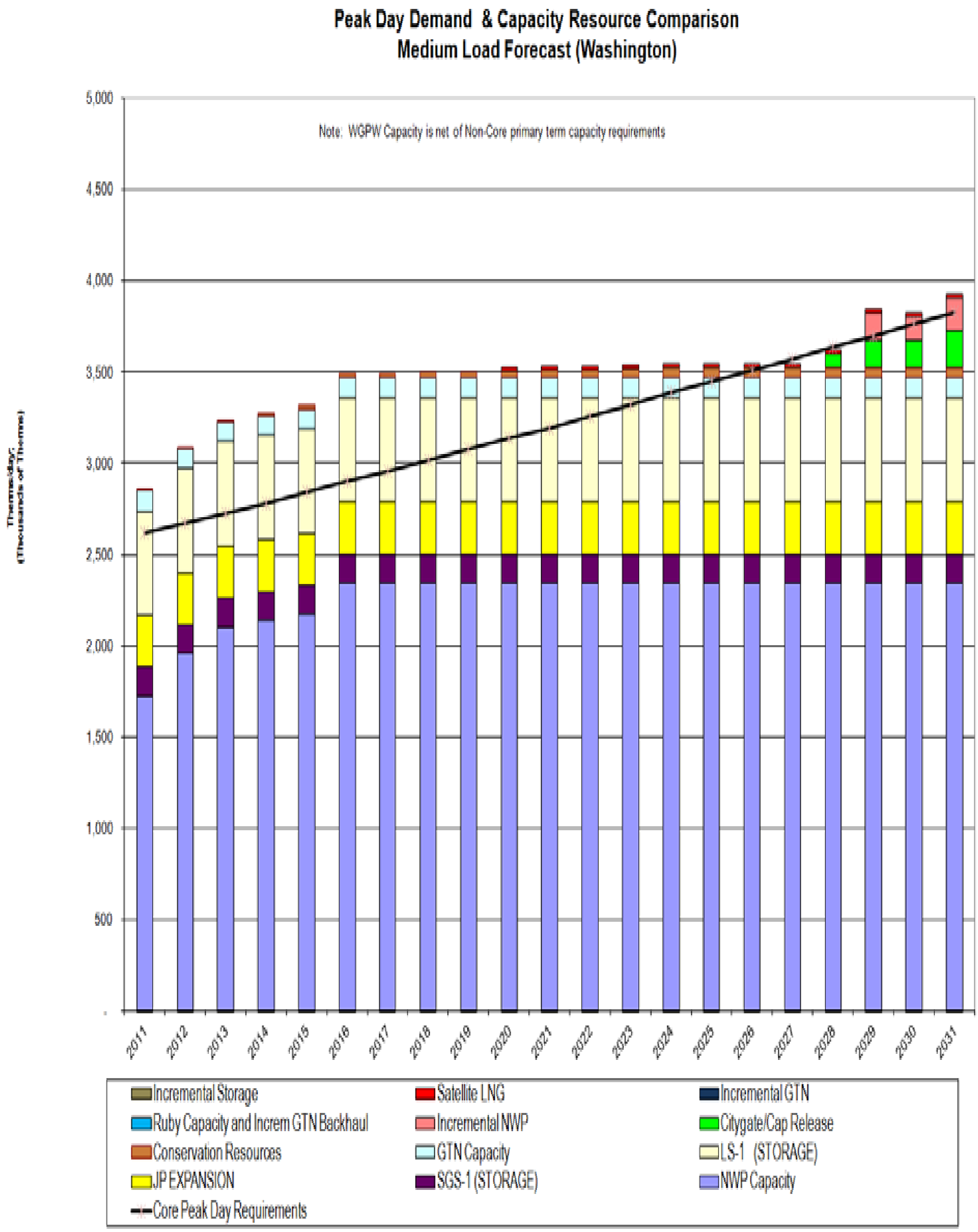

Peak Day Demand & Capacity Resource Comparison
Medium Load Forecast - Oregon
Therms/day
(Thousands of Therms)
1,400
1,200
1,000
800
600
400
200
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Incremental Storage
Satellite LNG
Incremental GTN
Ruby Capacity and Increm GTN Backhaul
Incremental NWP
Citygate/Cap Release
Conservation Resources
GTN Capacity
LS-1 (STORAGE)
JP EXPANSION
SGS-1 (STORAGE)
NWP Capacity
Core Peak Day Requirements

FIGURE 7-C-3


Peak Day Demand & Capacity Resource Comparison
Medium Load Forecast (Washington)
Note: WGPW Capacity is net of Non-Core primary term capacity requirements
Therms/day
(Thousands of Therms)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Incremental Storage
Satellite LNG
Incremental GTN
Ruby Capacity and Increm GTN Backhaul
Incremental NWP
Citygate/Cap Release
Conservation Resources
GTN Capacity
LS-1 (STORAGE)
JP EXPANSION
SGS-1 (STORAGE)
NWP Capacity
Core Peak Day Requirements

Annual Load Requirements and Weather Uncertainty

The annual load requirements will vary dramatically based on the weather assumptions. Through the use of SENDOUT™ Monte-Carlo functionality, the company has the ability to analyze the impacts of weather on its load forecast. Figure 7-D shows the overall expected range of the load forecasts, before considering load reductions that can be achieved through incremental conservation programs. The chart provides the upper parameter, which is based on the assumption that the high load growth forecast occurs, with the lower parameter occurring under the low load growth forecast. Capturing the uncertainty around the medium load growth forecast was accomplished through SENDOUT™'s 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. Figure 7-E provides a more in depth look at the medium scenario results. 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 results for the 20 year planning horizon.

Figure 7-D

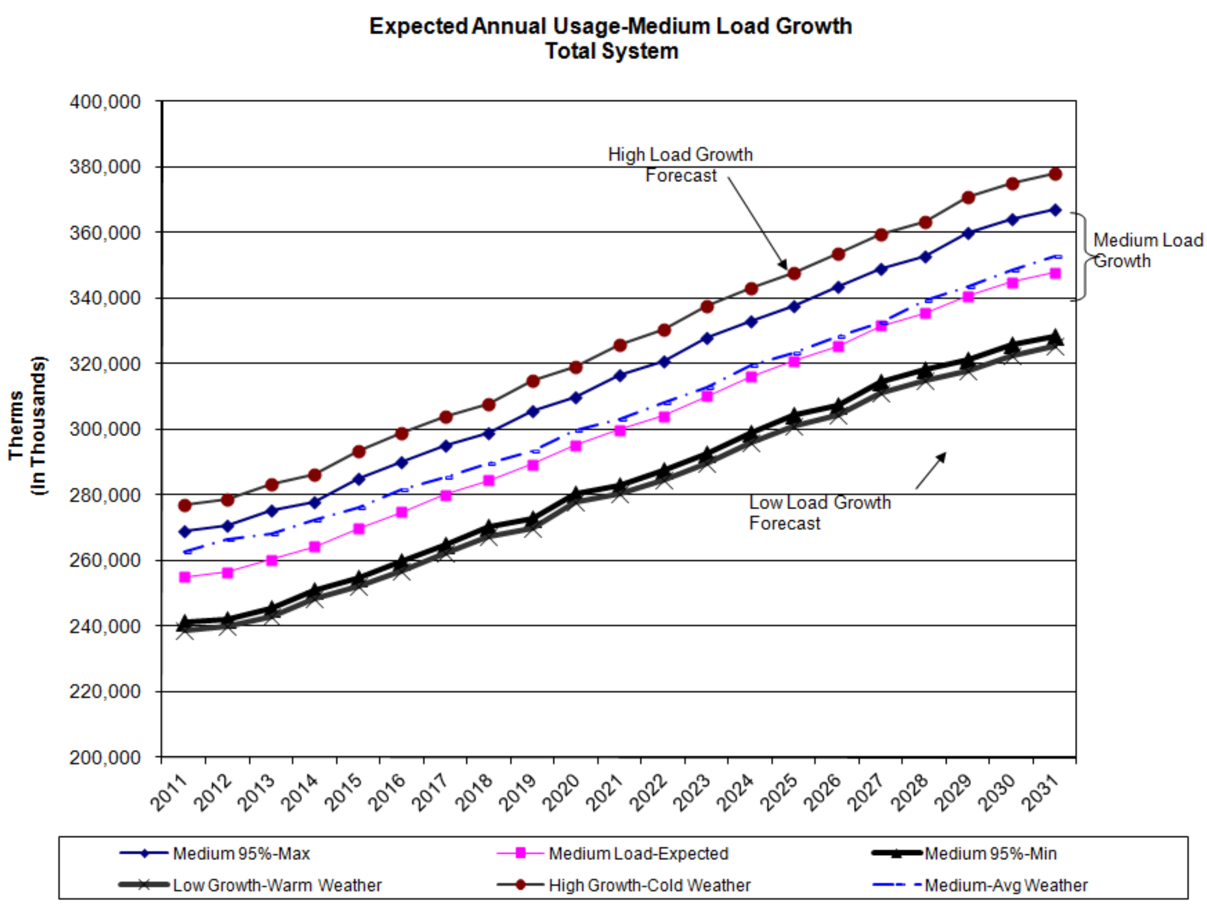
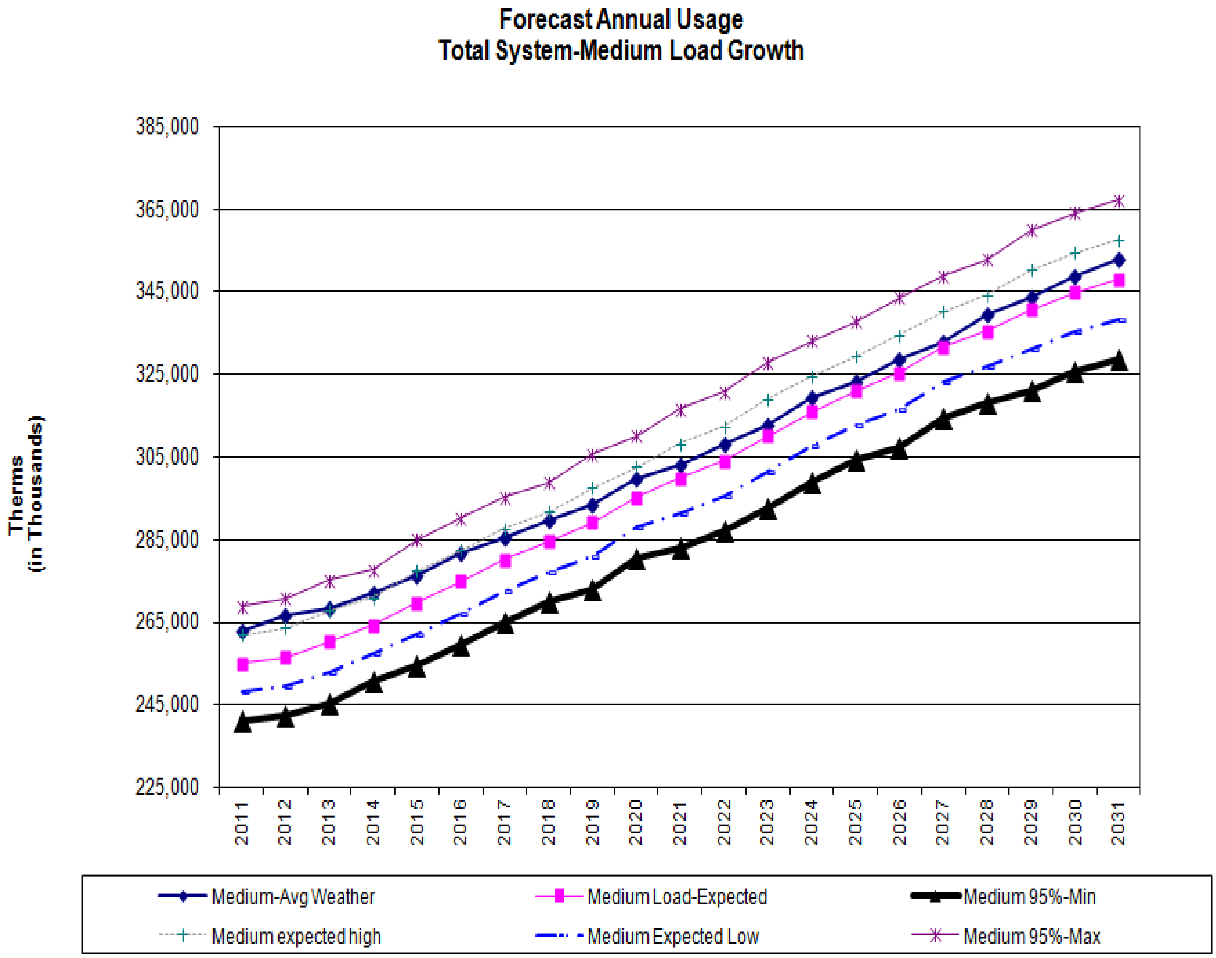


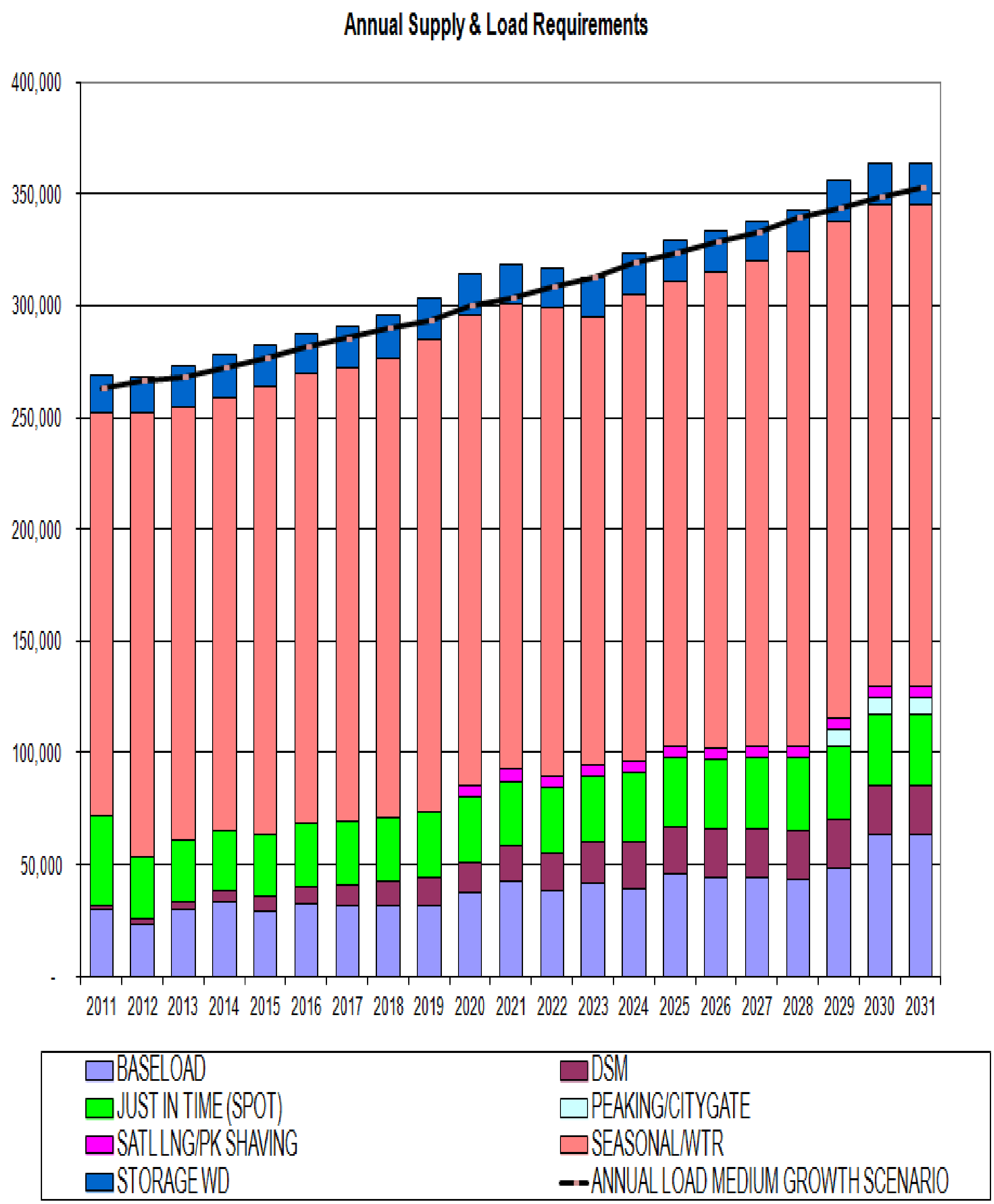
FIGURE 7-E



Additional tables and graphical analyses summarizing the weather and its impact on the annual load forecast are included in Appendix G-1.

To meet this demand, the company will need to acquire a blend of gas supply and conservation resources. For purposes of this plan, the company has estimated the level of conservation that is achievable over the course of the planning horizon which was discussed at length in Section 6. Figure 7-F shows how the company anticipates meeting the projected load over the planning horizon under the basecase scenario. Variations in the portfolio in order to meet actual load requirements during any year will occur primarily through the purchase of just-in-time, or spot gas purchases.

FIGURE 7-F


Annual Supply & Load Requirements
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
BASELOAD
DSM
JUST IN TIME (SPOT)
PEAKING/CITYGATE
SATL LNG/PK SHAVING
SEASONAL/WTR
STORAGE WD
ANNUAL LOAD MEDIUM GROWTH SCENARIO

<u>Impacts of Price Uncertainty and Overall System Costs</u>
The ability to accurately forecast long-term gas prices is influenced by two different types of uncertainty: uncertainty related to long-term changes in the industry and uncertainty related to short-term gas price variability. Contributing to long-term uncertainty are long term supply and demand issues, including growth in demand for electric generation, changes in LNG import infrastructure, possible pipelines to bring Alaskan and other frontier gas supplies to market. Short-term price variability also affects the long-term predictability of gas prices. Even if long-term supply and demand outcomes are exactly as projected, actual prices in future months will still reflect variability due to short-term market conditions. In order to estimate this uncertainty, the Company utilized SENDOUT's™ Monte-Carlo functionality, to analyze the impacts of price on the portfolio costs. Since natural gas is becoming more of a national market, the company believes that volatility in the NYMEX prices will have a far larger influence on the portfolio's price volatility compared to the volatility in the AECO, Sumas and Rocky Mountain basin differentials.

Figure 7-G shows the overall expected range of the NYMEX prices over the planning horizon. The absolute maximum and absolute minimum amounts depicts the minimum amount or maximum amount from the 200 draws for a particular year. The Absolute maximum/minimum does not represent any single draw result for the 20 year planning horizon.

FIGURE 7-G

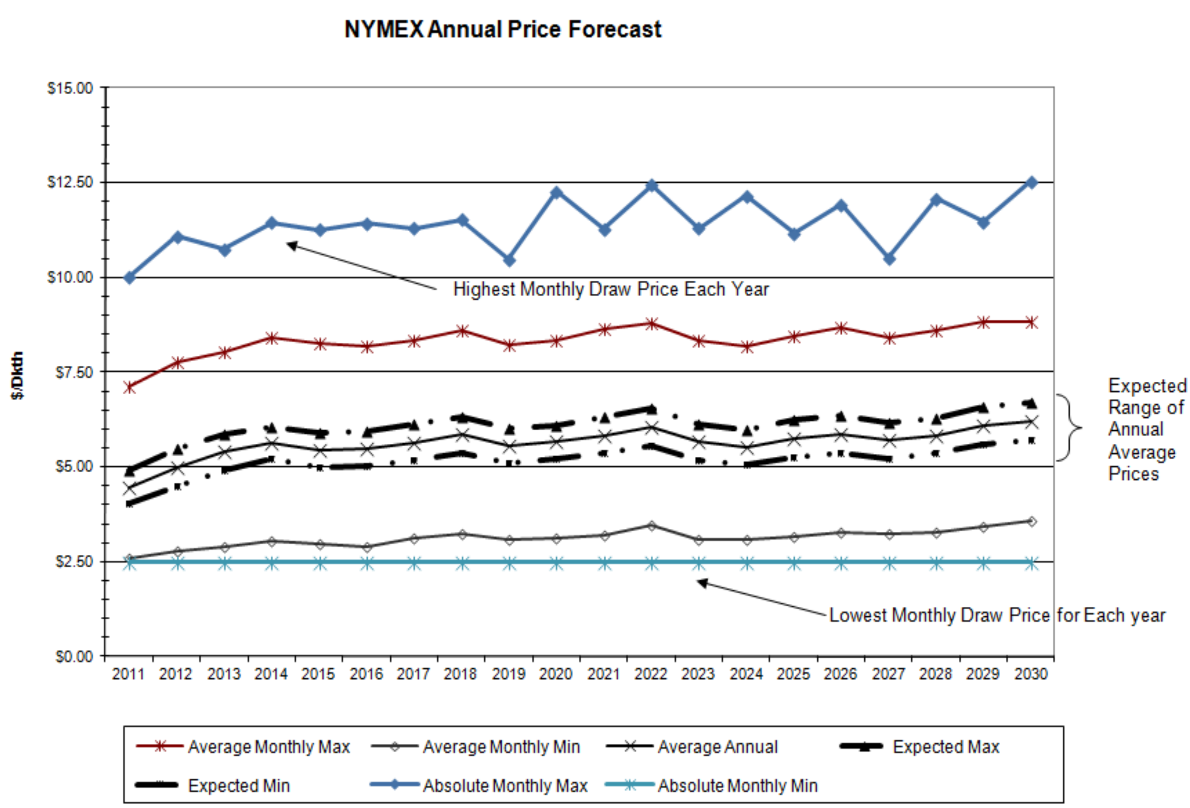


Figure 7-H compares the expected range of NYMEX prices from the Monte-Carlo analysis including the Environmental Externality costs that were discussed in Section 6. The highest anticipated NYMEX prices would result if the Scenario 3 Carbon Cost Adder was implemented in 2011. In that scenario, Carbon Cost Adder would increase the baseline forecasts by $1.85/dkth beginning in the first year, ramping up to $4.38/dkth over the 20 year planning horizon. The impact of the price volatility on the overall cost of the long- term portfolio is shown below in Figure 7-I. Further tables and graphical analyses summarizing the pricing simulations are included in Appendix G-2.

FIGURE 7-H
PRICE FORECAST-NYMEX
Average Annual Price

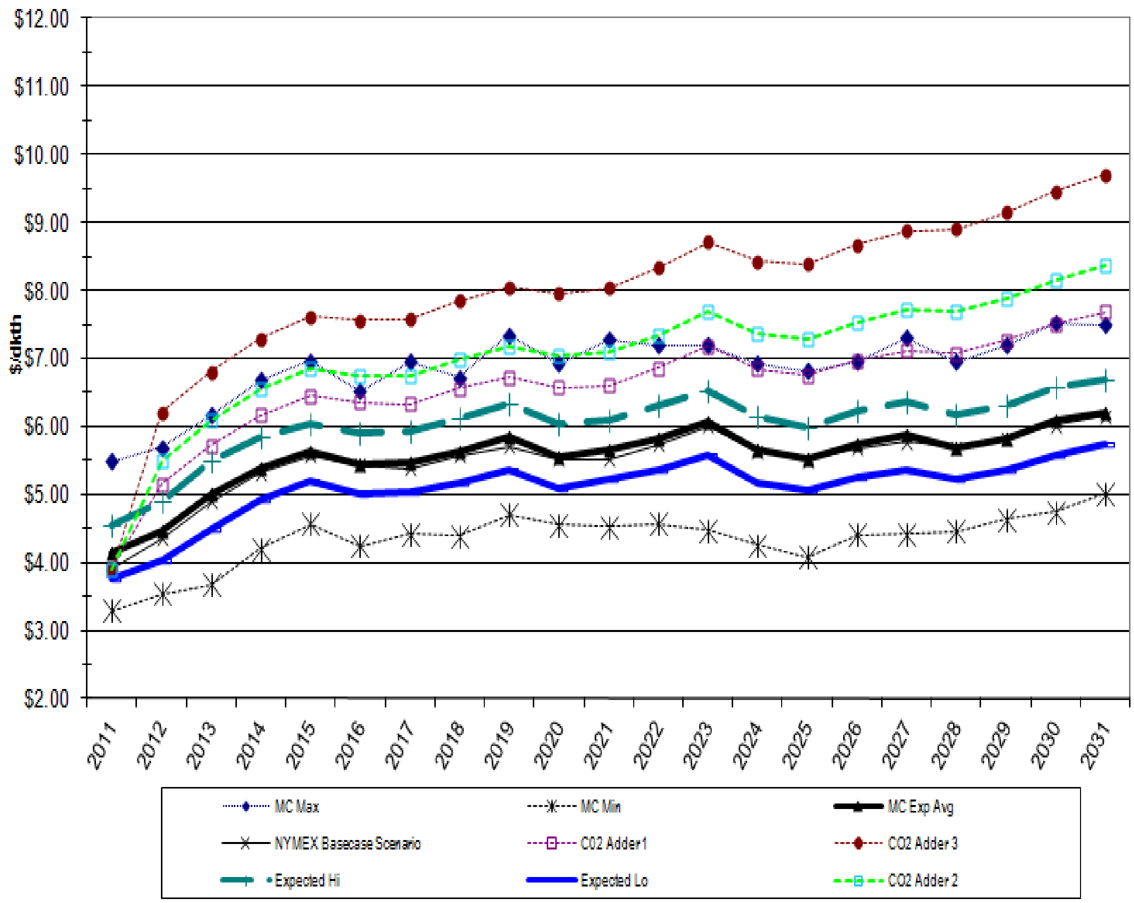


FIGURE 7-I
Annual Portfolio Cost

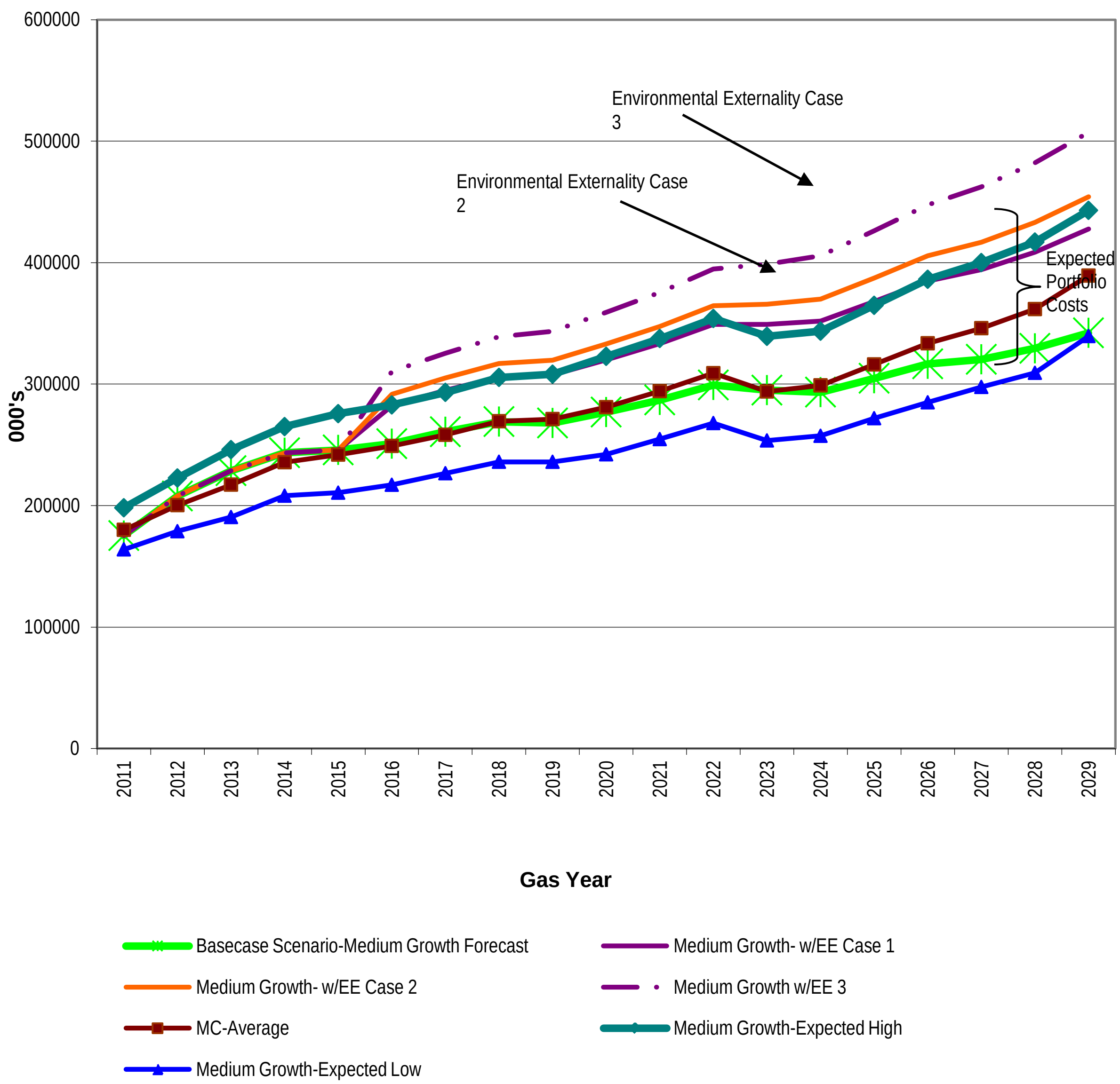


Table 7-5 summarizes the Net Present Value of the 20-year portfolio costs and average cost per therm for each of the scenarios and includes the anticipated range of costs from the Monte-Carlo modeling.

TABLE 7-5

	NPV 20 Yr Portfolio costs in $000s	Average Cost Per Therm
Scenario Results		
Basecase Scenario High Load Growth Low	$ 2,747,378	$ 0.388872
Load Growth	$ 3,267,486	$ 0.425008
Environmental Externalities Case 1	$ 2,657,113	$ 0.408042
Environmental Externalities Case 2	$ 3,149,964	$ 0.445903
Environmental Externalities Case 3	$ 3,272,814	$ 0.463253
	$ 3,518,517	$ 0.498047
Simulation Results		
Monte-Carlo Average	$ 2,816,873	$ 0.399799
Monte-Carlo Expected High	$ 3,216,376	$ 0.447916
Monte-Carlo Expected Low	$ 2,448,210	$ 0.354748

Based on the basecase results, Cascade has calculated its avoided costs. Cascade's avoided cost estimates represent the marginal cost of natural gas usage incremental to the forecasted demand. In other words, avoided cost is the unit cost to serve the next unit of demand during any given period of time. If demand-side management measures reduce customer demand, the Company is able to "avoid" certain commodity and transportation costs. This concept is important to assessing the proper value to demand-side management efforts. As discussed in Section 6, when calculating the avoided cost figures, the company includes an incremental cost advantage for conservation resources to recognize the non-quantifiable benefits associated with conservation such as price certainty and hedge value against future carbon costs.

Based on the annual costs from the Basecase scenario, the Company has estimated that the avoided costs are $11.02 for 30-year measures and the cost-effectiveness limit is 65 cents per therm. Under the Carbon Scenarios, the avoided costs for 30-year measures range between to $12.34 up to $13.56 or 73 to 80 cents per therm.

Additional information regarding the calculation of these avoided cost estimates is included in Appendix H.