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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of the Application of:	)	Docket No. CP22-2-000
	)	
Gas Transmission Northwest LLC	)	

ROGUE CLIMATE'S COMMENTS ON THE DRAFT EIS FOR THE GTN XPRESS PROJECT

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INTRODUCTION

The scope of FERC's procedural responsibilities under NEPA are directly related to FERC's broad grant of authority under the Natural Gas Act (NGA). FERC has the authority to regulate the transportation and sale of natural gas and to protect the public from the exploitative power of natural gas pipeline companies. The DEIS must, therefore, include the information and analysis necessary for FERC to exercise that authority through consideration and potential adoption of alternative means to accomplish the purpose of the project and measures to mitigate identified impacts. This means that means it must provide the information necessary to fully understand the need for the project. It does not. Instead, it avoids this discussion by misstating the need as the addition of Canadian gas molecules into the United States because shippers are willing to pay for them (as opposed to the shippers need to deliver energy services). And, it claims that NEPA does not require more because FERC has its own policy that it will apply later to determine if there is a need. FERC may later apply its policy of determining the need based solely on the existence of precedent agreements, but for NEPA purposes it must identify the bases for the decisions to purchase the gas which is the purported cause for the project.

This is necessary, particularly because the DEIS correctly discloses most of the GHG emissions and rightly monetizes them by calculating the social cost, SC-GHG, identifying, albeit not declaring, a significant environmental impact. Because of the impact, more information about the need must be analyzed to allow for the hard look discussion of alternative means and mitigation measures. Moreover, FERC's failure to declare the GHG emissions impacts "significant" is a failure to provide notice to the applicant and the public that alternative means and mitigation measures should be discussed and may be required. The NEPA requirement to characterize the emission impacts is different from FERC's later decision to approve or deny the project pursuant to its

Certificate Policy balancing. And, suffice it to say that the alternatives analysis and mitigation discussion in the DEIS is fatally flawed as a result of these structural problems. Rogue Climate provides what information it could find regarding the shippers' potential need and proposes alternative measures that should be considered to identify scope of the real need for energy services and ways to deliver them.

To cure these deficiencies, an amended DEIS must be issued to allow public access to and informed comment on the analysis.

Because FERC has authority to address the concentration of ownership of the pipelines and protect consumer interests - and the interests of landowners and communities as identified in FERC's Certificate Policy - against exploitation at the hands of private natural gas companies, the DEIS must consider all connected projects and the direct, indirect and commutative effects. Rogue Climate demonstrates here that there is currently a concentration of ownership and exploitation that must be addressed and can be addressed by first fully complying with the procedural requirements of NEPA.

Rogue Climate demonstrates that FERC (in furtherance with DOE) is the **legally relevant cause** of roughly more than $ **538 trillion** dollars in social costs of climate, environmental and social damage that consumers, communities, landowners, and the world will endure due to its approval in the last five years of 15 XPress projects related to TC Energy's pipelines. FERC's EIS in this case must discuss and characterize those connected actions and the commutative direct and indirect global warming impacts to determine whether adding $12 billion in damages for GTN's XPress project is significant. We wonder what mitigation might have been proposed by TC Energy in all of its XPress projects had FERC calculated and characterized the emissions impacts and deemed them significant.

II. THE DEIS DOES NOT SATISFY THE REQUIREMENTS OF NEPA.

NEPA is intended "to promote efforts which will prevent or **eliminate damage to the environment and biosphere** and **stimulate the health and welfare** of man..." and it established the Council on Environmental Quality (CEQ). 42 U.S.C. § 4321 (emphasis added). Agencies' application of NEPA must not be arbitrary and capricious, otherwise contrary to law or insufficiently supported by the record. Rogue Climate will argue throughout these proceedings (including in a soon-to-be-filled supplemental protest) that employing deliberate ignorance - the practice of refusing to consider or discuss logic or evidence disproving ideologically motivated positions ("nothing to see here approach") - is arbitrary and capricious decision-making.

A. FERC's Approval of this Project Will Be the Legally Relevant Cause of the Direct and Indirect Effects of the Release of an Additional 3.89 Million Metric Tons of GHGs, Resulting in over $ 12 Billion Dollars in Social Costs Related to Climate Change; Thus, the DEIS's Refusal to Analyze the Purpose and Need for the GTN Xpress Project Violates NEPA.

By saying that the DEIS need only briefly specify the purpose and need of the project and then attempting to do so by merely reciting that GTN's application says the project is necessary to serve a growing market demand, violates NEPA's requirements. The NEPA discussion of purpose and need must be robust and sufficient enough to inform the identification and analysis of alternatives, mitigation and the impacts of the proposed action itself.[1] The sufficiency of that effort is tied to the scope of FERC's authority.

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[1] "The statement shall briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action." 40 C.F.R. § 1502.13. CEQ regulations require that the agency discuss possible mitigation measures in defining the scope of the EIS, 40 CFR § 1508.25(b) (1987), and in discussing alternatives to the proposed action, § 1502.14(f), and consequences of that action, § 1502.16(h), and in explaining its ultimate decision, § 1505.2(c). And, "omission of a reasonably complete discussion of possible mitigation measures would undermine the "action-forcing" function of NEPA. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 351–52 (1989)

FERC's authority in this case is not merely a limited delegation from the Department of Energy. Here, FERC must "balance the public benefits against the adverse effects of the project . . . including adverse environmental effects" - requiring it to fully assess the "environmental effects of [projects] it approves," including the climate harms.[2] Having identified greenhouse gases as a primary contributing factor to global climate change and having the legal authority to deny the project based upon environmental effects, FERC is the legally relevant cause of the direct and indirect environmental effects of the project.[3]

Therefore, the only way to satisfy its NEPA requirements is to obtain complete and detailed information about where the 150 million cubic feet of gas is coming from, where it is going, what specific "growing market demand" is to be satisfied, where, when and why. All of this information is necessary to sufficiently inform the possible alternative actions and ways to mitigate impacts. The DEIS violates NEPA because the purpose and need is not analyzed. FERC has the power to request the information and to cause GTN to submit it.

Also insufficient is the DEIS's response to the EPA's request that the DEIS analyze and potentially determine if the "need" for the project - the growing market demand or otherwise - 1) could be met by deeming it what it is, a need for **energy services**, and considering whether the demand could be delivered with or without the project, 2) could be met by current production levels and capacity at a regional level, and 3) whether the need is a product of more wells or capacity being developed upstream. DEIS 1-4. The DEIS refuses the request stating that FERC does not have a "program" to direct the development of gas infrastructure and does not engage in regional planning

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[2] *Sierra Club v. FERC (Sabal Trail)*, 867 F.3d 1357, 1373 (internal quotation marks omitted). See also Certificate Policy at 27, *clarified* 18–19. (Adverse environmental effects subject to NGA § 7 are identified through FERC's compliance with NEPA).

[3] *Sierra Club v. FERC (Freeport)*, 827 F.3d 36, 47 (D.C. Cir. 2016).

"exercises." This is erroneous for several reasons.

First, the "exercise" EPA is requesting is nothing more than a request that FERC take the "hard look" NEPA requires at markets and supply and demand economics.[4] This would test the credibility of GTN's stated need or even the precedent agreements themselves and is not precluded by the Certificate Policy, at least, because it is separate from and necessary to the NEPA analysis.[5] Again, it would inform the identification of reasonable alternatives, potentials for mitigation and conditions of approval.

EPA's request, merely raises the possibility that there may be pressure or motive to enter into precedent agreements that are unrelated to the ultimate distribution of the gas to the public (as contemplated by the NGA), that there may be uncommitted capacity within the regional network, and that FERC should consider the purported "need" to be for **energy production** consumption (as opposed to a gas commodity (the gas molecules) in and of itself) which could be met in alternative ways (like efficiency and conservation). FERC has the authority and resources to make these analyses; there is clearly something to see here.

Set out below are just a few questions (and potential responses or other relevant questions) that may be posed and answered (if only to enable informed public comment):

What is the additional capacity TC Energy has added by its $1.2 billion dollar Canadian West

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[4] *See*, *Ctr. for Sustainable Economy v. Jewell*, 779 F.3d 588, 609 (D.C. Cir. 2015) (praising agency' "economic model" to assess substitution effects); *Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549 (8th Cir. 2003) ("the proposition that the demand for coal will be unaffected by an increase in availability and a decrease in price…is illogical at best"); and *Mid States*, 345 F.3d at 550 (noting the availability of "computer models that are widely used"to "forecast the effects of [a] project on the consumption" of energy sources).

[5] Statement of Policy, Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61227 (1999), clarified 90 FERC ¶ 61128 at 2 (2000), further clarified 92 FERC ¶ 61094 (2000) ("Certificate Policy").

Path Expansion and are the U.S. XPress projects - scaling up of gathering system compressor stations - in response to that the upstream expansion or additional well drilling? See Exhibit 1 (composite exhibit about TC Energy) informing potential answers.

What is TC Energy's current and future plans to export the additional West Path Expansion capacity through Kings Gate? (Is there a reasonable alternative for TC Energy to export this extra capacity to or through some other country, and through a different port of entry ?)

Have Cascade Natural Gas ("Cascade"), Intermountain Gas Company (Intermountain) or Tourmaline (affiliate of Canada's largest natural gas producer, focused on growth in exploration, development and production in the WCSB) (or its customers) (the "shippers") regularly released or traded their current firm capacity to the short-term or spot markets (the EBB market)? (Is trading on these markets more lucrative than providing service, given pressures to export Canadian gas through US and Mexican LNG terminals? What is the capacity for additional storage or making storage more efficient for uncommitted capacity on the GTN?)

Do the shippers intend to trade their additional precedent agreement capacity on the short or spot markets? (Should FERC impose a condition to prevent the release of this capacity to the short term or spot markets (albeit recognizing that there will be no GTN XPress tag on the molecules) or should it otherwise impose trading restrictions or incentives?)

What are the shippers' obligations (voluntary or regulatory) to reclaim capacity through efficiency or conservation, what are their forecasts for meeting those goals and have those forecasts been included in their determinations that there is "growing demand?" (Should FERC impose conditions that allow the extra capacity to be delivered only until those goals are met or required to be met?)

What is the likelihood or possibility that the gas will not be distributed to the public for energy production?

Which ratepayers may be burdened with the costs of the project and potentially burdened by stranded assets due to anticipated/foreseeable federal and state regulation reducing natural gas GHG emissions? (Should FERC impose conditions to ensure that only TC Energy bear the costs of that potential?)

This information is necessary for the NEPA analysis and should FERC persist in its opinion that such information and analysis is outside the scope of the NEPA process (and is only necessary for its Certificate Policy process), parties will be forced to seek this information though a discovery request and/or hearing request further complicating TC Energy/GTN's application review process.

Second, simply saying there is no "program" to direct the development of gas

infrastructure does not jettison FERC's NEPA responsibility. FERC has the authority to affect the development of gas infrastructure. It has authority to regulate (deny or require mitigation and conditions) the business of **transporting and selling** natural gas and FERC has regulated the selling of gas. There need not be a "new rule" enacted or plan adopted for FERC to assert its selling-of-gas oversight authority in the context of NEPA's requirements for a robust analysis of alternatives and mitigation opportunities. All that is needed and required is a preliminary robust discussion of what the need is. To recap, having the authority regulate the selling of gas, shapes the scope of FERC's NEPA analysis because FERC's exercise of its authority - all of its authority - will be the legally relevant cause of the environmental impacts.

Third, even if a program would help for some types of mitigation, FERC has a duty to engage in "informed decision making" regarding the greenhouse-gas emissions effects of this project, and provide the required opportunity for "informed public comment" simply because it can mitigate the impacts.[6] The DEIS does not do this.

B. The Alternatives Analysis in the DEIS is Fatally Flawed

1. It is Flawed Because it Defines the Purpose to Preclude Any Analysis of A No-Action or Alternative Energy Systems Alternatives

The DEIS defines the purpose of the project to be to increase gas capacity - the gas flowing - on the GTN system by about 150 million standard cubic feet per day and then declares that alternatives that do not do so cannot be considered. DEIS 3-1. FERC's position that the purpose of the project is to put extra gas molecules from Canada in the GTN pipeline, renders the alternatives analysis completely useless and presents absolutely no support for the primary justification for the Project. Alternatively, the DEIS fails to acknowledge that there are alternative

[6] *Sabal Pass,* 867 F.3d at 1374 (FERC "has legal authority to mitigate" downstream emissions).

ways to "increase capacity" without adding new gas molecules. Below Rogue Climate attempts to fill in some of the blanks to demonstrate what the DEIS's alternative analysis could look like after FERC corrects its erroneous focus on a new-molecules-from-Canada purpose.

2. It is Flawed Because It is Based on the Unsupported Premise that there is a Market Demand for the Project

The DEIS acknowledges, "the no-action alternative provides the benchmark for decisionmakers to compare the magnitude of environmental effects of the proposed activity and alternatives." Yet, it equates the no-action alternative with the Commission's determination of need for the project under its Certificate Policy and states that a review of the market and GTN's contracts would not inform its alternatives analysis. DEIS 3-1. It is saying the no-action alternative is outside the scope of the DEIS, because it is up to FERC to later determine if there is a market. This is incorrect. If the DEIS will not discuss what FERC says is the very purpose of the project - the market need - the alternatives analysis is made completely useless. FERC cannot ignore its duty to assess the market need until it is ready to take up the Certificate Policy criteria. It is fundamentally part of the NEPA process and drives the "action-forcing" function of NEPA.[7] Doing the opposite of what is acknowledged to be required is a classically arbitrary action.

Moreover, FERC cannot avoid its NEPA obligation by deferring its analysis to a process that does not meet the same standard.[8] While the Certificate Policy may allow FERC to rely on precedent agreements for its determination of purpose and need, NEPA requires FERC to take a hard look and fully analyze alternatives which it cannot do without a full understanding of the purported demand - where it is, what it is, etc. Said another way, a precedent agreement is an

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[7] *Methow Valley Citizens Council*, 490 U.S. at 352.

[8] *Friends of the Earth v. Haaland* __F Supp 3d __*9 (2022).

unsupported premise of the need for the project to fulfill FERC's NEPA alternative analysis requirements.

3. It Is Flawed Because it Fails to Consider Alternatives That Could Meet the Purported Market Demand by Other Means.

Even assuming there is a growth demand, to satisfy the NEPA requirements the DEIS must consider the following alternatives:

a. A no-action/systems alternative which assesses whether all or what part of the 79,000 Dth/d that Intermountain will take to provide energy services may be obtained or substituted through the following measures, individually or in combination:

i) Obtaining extra current or future available firm capacity on the Williams Northwest Pipeline (NWP). Intermountain takes gas at the Stanfield Oregon interconnect with access to both the NWP and GTN pipelines.[9] In fact, Intermountain's recent contracting efforts related to its firm transportation rights on the NWP, will result in it holding excess capacity until 2025, which it intends to release to buyers on a short term basis.[10]

ii) Retaining capacity or maximizing capacity through a more efficient use of the short-term and spot markets on either the GTN or Williams line. Intermountain's 2020

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[9] Exhibit 2 is Intermountain's Integrated Resource Plan which states:

> Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Energy via Nova, and Foothills pipelines) and two U.S. pipelines (Gas Transmission Northwest (GTN), and Williams Northwest Pipeline, (NWP)) as seen below in Figure 23.

Ex 2 at 57.

> Intermountain holds firm capacity on four different pipeline systems including NWP. NWP is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system (other than Nampa LNG) via citygate taps with NWP.

Ex 2 at 64.

[10] *Id.*

IRP boasts of its ability over the last 15 years to generate millions of dollars per year by releasing its firm transportation capacity rights on these markets.[11] Intermountain admits that it has obtained significant amounts of unutilized capacity mitigation on NWP and GTN via capacity releases and frequently uses segmentation releases and also participates in bundled service releases.[12] Intermountain attributes its ability to do this to FERC's "gas deregulation" beginning in 1985 in Order 436. Clearly FERC has the authority and the expertise to consider whether Intermountain's current capacity is sufficient or could be sufficient if it was not releasing its capacity for profit. Just in June of this year, Intermountain released 43,799 in the short-term market.[13]

iii) Increasing or more efficiently utilizing storage capacity.

Intermountain uses storage capacity at four facilities, two operated by NWP and include liquified gas storage. Intermountain states that it is poised to reduce its dependence on third-party supply because, with a reduction in LNG delivery risk, it may transport the LNG stored at its Nampa LNG facility around the state in a timely manner. The alternative analysis should consider how much of the purported new demand might be provided by use of Intermountain's current storage resources or additional storage resources and by its ability to satisfy industrial consumer demand through LNG delivery.

iv) Increasing available current and future capacity by reducing the load through efficiency and optimization measures by Intermountain (like LAUF) and its customers (Core Market Energy Efficiency). Intermountain has plans and programs to optimize its distribution system and promote the efficient use of the system. It reduces waste through its Lost and

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[11] *Id.*

[12] *Id.* at 68

[13] *Id.* at 160

Unaccounted For (LAUF) natural gas program. And, while Intermountain admits that it does not want its consumers to use less natural gas, its environmental policy adopted in 1991 and updated in 1998, caused it to develop a demand side management program designed to "displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcement on the Company's distribution system." Ex. 2 at 82. The program was projected to result in about 375,000 them savings in 2021. And, Intermountain's conservation assessment tool identifies the conservation potential for residential and commercial sectors over the 2020-2039 time period, showing a gas savings which appears to be 6 - 10 million therms in 2023 and 2024. *Id.*

The necessary NEPA alternatives analysis requires consideration of these alternative measures to determine whether all or a portion of the 79,000 Dth/d is needed. There are models and federal and state agencies that FERC may rely upon to do this analysis. And it must be done because FERC's approval will deny the application of state and local law and policy to do the analysis. Such preemption will violate federal constitutional limitations (further discussed below).

b. Similarly, a no-action/systems alternative which assesses whether all or what part of the 20,000 Dth/d that Cascade will take to provide energy services may be obtained or substituted through the following measures, individually or in combination:[14]

i) Obtaining extra current or future available released firm capacity on

[14] In its 2020 Integrated Resource Plan, Cascade states that it has acquired unsubscribed capacity on the GTN primarily to serve Central Oregon. Ex.3 at 66, 188. It also stated that, after acquiring that 10,000 Dth/d from GTN, and an additional 30,000 Dth/d in late 2019, it could not identify any shortfalls over the planning horizon:

> This is in large part a function of an additional 10,000 dth/day of GTN, 20,000 dth/day of NGTL, and 10,000 dth/day of Foothills capacity acquired in late 2019, which allows the Company to flow additional gas to central Oregon citygates that had forecasted shortfalls in previous IRPs.

Ex 3 at 190.

the NWP. Cascade also has access to gas from a variety of suppliers and transmission pipelines.[15] Cascade's IRP lists several pipeline capacity projects for which it may acquire additional capacity on the NWP line. In fact, Cascade states that a 10,000 Dth/d deficiency identified in its 2018 Supplemental IRP was addressed with a realignment proposal from NWP which Cascade accepted in June 2019. Ex 3 at 60. Yet, it apparently determined it needed an additional 10,000 Dth/d of "currently **unsubscribed capacity** on GTN" to serve Central Oregon. *Id.* at 66. This raises serious questions about reliance on Cascade's precedent agreement that must be investigated.

ii) Retaining capacity or maximizing capacity through a more efficient use of the short term and spot markets on any or either of the GTN or the NWP. Cascade's NWP realignment package provided opportunities to release capacity and segment capacity to meet its goals. The possibility of satisfying any or all of the purported additional 20,000 Dth/d demand by reducing its releases or acquiring short-term releases must be explored as an alternative.

iii) Increasing or more efficiently utilizing storage capacity. Cascade also has storage resources and acknowledges that storage is not just to manage peak demand but is an "important gas supply management tool." *Id.* at 57.

iv) Increasing available current and future capacity by reducing the load demand through efficiency, demand management, optimization measures, and adoption of/compliance with state and local GHG emission reduction targets, including the City of Bend's climate action plan. See Ex. 3. Cascade employs all such tools.

4. It is Flawed Because, as Discussed, the lack of Information about

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[15] Cascade purchases natural gas from a variety of suppliers and transports its gas on three gas pipeline companies, Northwest Pipeline LLC (NWP), Gas Transmission Northwest (GTN), and Enbridge (WCT) provides British Columbia gas directly into the Company's distribution system. Cascade also holds upstream transportation contracts on [T.C. Energy's] Foothills Pipeline (FHBC), NOVA Gas Transmission Ltd. (also known as NGTL). Ex. 3 at 26.

Which Customers or Class of Customers Will Ultimately Receive the 51,000 Dth/d Extra Gas That Tourmaline Will Take Makes it Impossible to Identify Any Alternatives, Consider All of the Impacts and to Provide for Informed Public Comment.

The task of identifying alternative measures/systems for the affiliate of Canada's largest producer of gas, Tourmaline Oil Co., is impossible to demonstrate because there in no evidence, in the record or otherwise, from which to determine where the gas is going (other than to Northern California), whether Tourmaline could obtain some or all of that capacity from "currently unsubscribed" firm capacity on the NWP, who will distribute it, how it will be consumed and whether, similar to the regulated utilities - Intermountain and Cascade Natural - Tourmaline or its distributors and customers have tools, plans and resources to avoid or reduce the gas acquisition. FERC has authority and has used it to require information about shippers' downstream end use of the gas. In fact, in the ANR XPress proceedings, TC Energy responded to such a request and disclosed that Tourmaline would use 140,000 Dth/d of the new capacity to deliver to Cheniere Energy, Inc. for exportation.[16] FERC needs to ask for the information.

Nevertheless, we do know that Tourmaline relies on other transportation services on interconnecting pipeline systems to get its gas to Northern California. It has entered into the precedent agreement "to participate in increasing market demand in Oregon and California." The additional capacity at issue "will also allow Tourmaline to provide gas supply which will assuage demand in **southern markets** when intermittent renewables, such as wind and solar, are not available."[17]

To comply with NEPA, FERC must seek the obscured information about Tourmaline's end

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[16] Document Accession #: 20210722-5127, p.3

[17] Document Accession #: 20211109-5135, p. 2-3

use. The DEIS must then provide an alternatives analysis regarding Tourmaline's 51,000 Dth/d. And, the DEIS must include an analysis of how California's GHG emission regulations, tools, and incentives would or could affect that forecasted need or the need over the term of the precedent agreement and how the additional downstream GHG emissions will impact California's GHG emission inventory and reduction goals/mandates.

C. The DEIS Greenhouse Gas Emissions and Climate-related Impact Acknowledgments Requires a Significance Determination and a Mitigation Analysis Which Are Nonexistent or Inadequate

The DEIS makes "significance" and mitigation determinations as to some environmental impacts - but refuses to do so regarding the GHG emissions. This is another classic example of arbitrary decision-making. Staff interprets the NEPA obligation to only require such analysis when it may point to a discreet, quantifiable, physical effects from the incremental GHG "contribution." DEIS 4-44. But this is not a correct application of the law. The law requires a significance decision and a mitigation discussion:

> As we have noted, greenhouse-gas emissions are an indirect effect of authorizing this project, which FERC could reasonably foresee, and which the agency has legal authority to mitigate. See 15 U.S.C. § 717f(e). The EIS accordingly needed to include a discussion of the "significance" of this indirect effect, see 40 C.F.R. § 1502.16(b), as well as "the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions," see *WildEarth Guardians*, 738 F.3d at 309 (quoting 40 C.F.R. § 1508.7).

Sabal Pass, 867 F.3d at 1374. See also 40 C.F.R. § 1502.16(a)(9)(the means to mitigate adverse environmental impacts must be included in the discussion).

Moreover, these requirements may not be avoided by kicking the can down the road, again. Both NEPA and the Certificate Policy itself require the significance determination be made in the DEIS process. Yet, the DEIS, erroneously claims that FERC is excused because the Commission will later determine, in rule making proceedings (that have been ongoing for five years, now) how it will determine how much incremental GHG emissions are significant - the "significance

determination." FERC does not interpret and enact NEPA, the CEQ does.

FERC's rule making (PL18-1-000) - the pending generic proceeding referenced in the DIES - may well set thresh-holds or limits or guidance for FERC to rely upon in denying an application under the Certificate Policy based upon the environmental impacts of the project identified through the NEPA process, but denial under the Certificate Policy is a separate, later decision. And because the Certificate Policy itself specifically states that the environmental impacts it may consider to deny the project will be identified through the NEPA process, the question begged, is what is the intent to completely avoid characterizing the impacts in the EIS? Commission staff may not kick it down the road for these two reasons, and doing so is another example of classic arbitrariness.

Finally, the NEPA "significance determination" has to be made in the DEIS precisely because it will provide notice to and allow the applicant, the Commission Staff and the public to know when, how and why to propose and analyze alternatives and mitigation.[18] As it stands now, TC Energy/GTN has no incentive propose reasonable alternatives or mitigation, hoping/knowing that FERC will continue it pattern and practice of ignoring the environmental and social impacts of shipping off additional methane gas molecules to be burned.

As for the merits, there is sufficient evidence to declare even this so-called incremental addition of GHG emissions a significant environmental impact.[19] The additional 3,890,000 tons of

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[18] FERC's 'wait and see' approach to mitigation will not suffice under NEPA because it precludes informed decision-making. *Great Basin Res. Watch v. Bureau of Land Mgmt.* , 844 F.3d 1095, 1107 (9th Cir. 2016).

[19] The GHG impacts should be enough to deny this project under the Certificate Policy because this project will produce over 3.2 million metric tons of CO2e per year in just operations and downstream emissions. The Interim Policy Statement, issued on February 18, 2022 and withdrawn soon thereafter, found that 100,000 mtpy Co2e emissions posed a significant environmental impact. The Commissioners, however, will have to determine if something more than 100,000 mtpy or even more than the 165,000 mtpy operational emissions of the East Lateral XPress project approved in March, is significant for denial. FERC may not wait to establish a metric or

GHGs costing over 12 billion dollars in social costs and damages to the environment, captive energy users, communities, and landowners is "significant" so alternative means to meet the unanalyzed need must be proposed and considered.[20]

The Social Cost-GHG (SC-GHG) analysis is the best available science and methodology to incorporate the value to society of net changes in direct and indirect GHG emissions resulting from a proposed action. The EPA has been urging the Commission to use this tool for years. And the Court has clarified that FERC is required to do so pursuant to 40 C.F.R. § 1502.21(c).[21] That the tool is still being refined through peer review regarding the discount rate and that it does not identify what level of the monetized cost is significant does not diminish the acceptability of the tool.[22]

So, because we know that this 75 million dollar project will cause more than $12 billion in environmental and societal damages, it would be arbitrary not to declare that it presents a significant environmental impact and the DEIS is fatally flawed because it does not say so.

Finally, whether the DEIS decides to call it significant or not, the necessary calculation of the emissions and their effects is presented and so the DEIS must include a discussion of possible mitigation measures:

> ... [O]mission of a reasonably complete discussion of possible mitigation measures would undermine the 'action-forcing' function of NEPA. Without such a discussion, neither the

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policy in rule making, however.

[20] This GHG Mtpy calculation includes the upstream emissions calculated by Peter Erickson and submitted by Columbia Riverkeeper. The social cost calculation does not include the costs associated with the upstream emissions (.65 million tons) so the social costs could well be over 13 billion.

[21] Pursuant to 40 C.F.R. § 1502.21(c)(4), FERC is required it to use the social cost of carbon protocol or some other generally accepted methodology to assess of the impact of the projects' greenhouse gas emissions. *Vecinos para el Bienestar de la Comunidad Costera v. FERC*, 6 F.4th 1321, 1329 (D.C. Cir. 2022)

[22] *Id.*

> agency nor other interested groups and individuals can properly evaluate the severity.
>
> ***
>
> .... CEQ regulations require that the agency discuss possible mitigation measures in defining the scope of the EIS, 40 CFR § 1508.25(b) (1987), in discussing alternatives to the proposed action, § 1502.14(f), and consequences of that action, § 1502.16(h), and in explaining its ultimate decision, § 1505.2(c).

Methow Valley 490 U.S. at 352. Among others, those mitigation measures could include those potential alternative measures discussed above: minimizing leakage and mandating energy efficiency, attaching conditions that limit the quantity of gas transported through a pipeline or the time period, etc. Just as energy efficiency can offer an alternative choice to reduce the number of additional gas molecules needed to be burned, it can produce a result that is less severe in impact than burning new gas molecules. The DEIS must evaluate mitigation measures to address the significant GHG emission impacts.

D. The DEIS Is Fatally Flawed Because It Fails to Consider All Connected, Direct, Indirect and Cumulative Effects.

One of the purposes of the NGA is to address the concentration of ownership of the pipelines and protect consumer interests - and the interests of landowners and communities as identified in FERC's Certificate Policy - against exploitation at the hands of private natural gas companies. This broad authority informs the scope of FERC's NEPA duties to consider connected, cumulative, and similar actions, as well as direct, indirect, and cumulative impacts. 40 C.F.R § 1508.25(a), (c); 40 C.F.R. § 1508.8; and see also, *Sierra Club v. FERC*, 38 F.4th 220, 233–34 (D.C. Cir. 2022). FERC has failed to consider the upstream GHG emissions impacts (and include them in the SC-GHG analysis) of this project, and it has failed to consider all of the emissions and social costs of the connected XPress projects that directly, indirectly and commutatively contribute to climate change. These are fatal flaws.

The GTN XPress Project is one part of several projects contributing to massive infrastructure expansion for gas. In the past five years, FERC has approved the following 15 XPress projects, of which TC Energy owns (or has an interest in) all but one of the pipelines:

1. TCE's North Baja, 179 FERC ¶ 61,039 (April 21, 2022) - 495,000 Dth/d - ($ 14 .1 billion total SC-GHG).

2. TCE's ANR Alberta, 179 FERC ¶ 61,040 (April 21, 2022) - 165,000 Dth/d (Operations 121,252 mtpy, downstream (15,000) domestic - 289,682 totaling 410,934 mtpy; exported downstream, upstream emissions and SC-GHG currently unstated/unfound).

3. TCE's C.Gulf T. East Lateral, 178 FERC ¶ 61,198 (March 25, 2022) - 183,000 Dth/d
($5 billion in SC-GHG (excluding currently unstated upstream emissions)).

4. TCE's IGTS Iroquois, 178 FERC ¶ 61,200 (March 25, 2022) - 125,000 Dth/d (Intervenor Estimated over 140 million (operation) SC-GH; Otherwise emissions and SC-GHG currently unstated/unfound)

5. TCE's C. Gas T. Bukeye, 170 FERC ¶ 61,045 (January 23, 2020) - 275,000 Dth/d (downstream, upstream emissions and SC-GHG currently unstated/unfound)

6. TCE's ANR Grand Chenier, 171 FERC ¶ 61,233 (June 18, 2020) - 400,000 Dth/d (Operations 242,137; downstream exported emissions, upstream emissions and SC-GHG currently unstated/unfound)

7. TCE's PNGTS Westbrook, 171 FERC ¶ 61,234 (June 18, 2020) - 123,973 Dth/d (Operations 234,560 mtpy, downstream +800,00 (only includes one domestic shipper); other downstream, the upstream and the SC-GHG currently unstated/unfound)

8. TCE's C. Gulf T. Louisiana, 172 FERC ¶ 61,260 (September 17, 2020) - 493,000 Dth/d
(Operations 972,400 mtpy; downstream, upstream and SC-GHG currently unstated/unfound)

9. TCE's PNGTS Portland, 166 FERC ¶ 61,134 (February 21, 2019) - 137,387 Dth/d (2.66 million mtpy downstream emissions; operations, upstream and SC-GHG currently unstated/unfound.)

10/11. TCE's C. Gas T. Leach, 158 FERC ¶ 61,046 (January 19, 2017) - 1,530,000 Dth/d
And
TCE's C. Gulf T. Rayne, 158 FERC ¶ 61,046 (January 19, 2017) - 621,000 Dth/d

(Combined new capacity (molecules) 1,301,000 Dth/d resulting in 806,000 mtpy operation emissions, 25,177,342 mtpy downstream emissions and 1.2 million mtpy upstream emissions, SC-GHG currently unstated/unfound)

12/13. TCE's C. Gas T. Mountaineer, 161 FERC ¶ 61,314 (December 29,2017) - 860,000
And
TCE's C. Gulf T. Gulf, 161 FERC ¶ 61,314 (December 29, 2017) - 860,000
(Total capacity of 2,700,000 Dth/d resulting in 52.3 million mtpy in downstream emissions; operational, upstream and SC-GHG currently unstated/unfound)

14. TCE's CGT WB XPress, 161 FERC ¶ 61,200 (November 17, 2017) approving 1.3 million Dth/d.
(No discussion of quantified emissions or social costs in decision)

15. Tuscarora, 175 FERC ¶ 61,147 (May 20, 2021) approving 15,000 Dth/d (operations 7,553 mtpy; downstream 289,700 mtpy; upstream and SC-GHG currently unstated).

The DIES must identify the total emissions - upstream, operations, downstream domestic and foreign and calculate the SC-GHG of them to determine whether adding another $ 12 billion in social costs is significant and ultimately warranted. As a rough calculation, the extra 6 million Dth/d FERC has authorized (or partially authorized (facilitated) with the US Department of Energy) in just five years (while FERC has been studying its Certificate Policy) has locked in and will cost more than $ 538 trillion in social and environmental damages/costs. Calculating these things is the purpose of NEPA.[23] The DEIS fails to comply.

FERC must update the GHG analysis to identify these connected actions and discuss the commutative impact of adding a 12 billion-dollar burden.

E. The DEIS Insufficiently Addresses Environmental Justice and related Environmental Impacts

1. Outreach Failure

[23] NEPA was enacted in the 1970s about 40 years after the NGA so it will do no good to say-it-ain't-so or that there is nothing to see here because FERC prefers to be in a 1930s time-capsule.

The DEIS notes that CEQ's policies recommend that through the NEPA process,

> Federal agencies provide opportunities for effective community participation in the NEPA process, including identifying potential effects and mitigation measures in consultation with affected communities and improving the accessibility of public meetings, crucial documents, and notices.

DEIS at 4-20(Citing to 1997 CEQ Guidance at 4). It also notes a similar recommendation in Section 8 of Executive Order 13985 to: "consult with members of communities that have been historically underrepresented in the Federal Government and underserved by, or subject to discrimination in, federal policies and programs." The DEIS does not mention FERC's Equity Action Plan which tasks the Office of Public Participation (OPP) with interacting with the public and soliciting participation at FERC. The DEIS rightly acknowledges, however, that this outreach has not occurred. Notices have been sent and the OPP is standing-by, ready to assist but no one, not even GTN appears to have attempted to contact affected communities. If there had been earlier information provided that FERC would not do it or require it to be done, Rogue Climate may have been able to submit a report on such outreach in response to the DEIS.

But, Rogue Climate learned that OPP has not and is not yet capable of conducting such outreach. Rogue Climate has spent resources to date to do so but has not had sufficient time to make the contact, assimilate the response or organize the community participation. Rogue Climate has asked for an extension of the DEIS comment deadline to continue its efforts and make the information available to the parties and public in the NEPA process. This deficiency requires FERC to engage in the outreach or an extension of the comment deadline for others to do it.

2. Failure to Determine and Consider Air Pollution Emissions Down the Line

The DEIS incorrectly limits the scope of its review to the three compressor stations that will be enhanced. There are four compressor stations down the line from the Kent station in Oregon: Madras #11, Bend #12, Chemult #13 and Bonanza #14. See Ex. 4. The DIES does not but should

discuss whether the expansion will create additional direct blow-down emissions at those compressor stations because of the extra pressure on the line (increasing the size of the releases) or simply because the expansion causes additional stress which will require additional maintenance. It should also discuss whether there are environmental justice communities, particularly those with a high than normal prevalence of asthma, near those stations - within a 2 mile radius - and analyze the impacts to those communities.

Two of those stations are subject to haze control measures to reduce Nox emissions. Ex. 4. The DEIS should investigate the air quality issues and confirm that the expansion will not produce additional Nox and other health effecting emissions or quantify what will produced and determine if they are significant or otherwise may impact to any degree environmental justice communities within five miles of the stations.

3. Noise/Wildlife Impacts Analysis is Insufficient

The DEIS fails to consider noise impacts to the winter range of elk and mule deer in which the Kent station is located. See GTN Application p. 3-7, 3-8. The DEIS must determine whether the Kent facility expansion may increase impulse sound that would effect quite areas which include wildlife breeding areas. See OAR 340-035-0015.

F. The DEIS Fails to Adequately Address Inconsistencies with State Plans and Law, Implicating Tenth Amendment Preemption Issues

NEPA directs federal agencies to cooperate with state governments, too. And it requires a discussion of inconsistencies of a proposed federal action with state plans. 40 C.F.R. § 1506.2 (c),(d) The DEIS fails to meet these requirements.

Washington, Oregon and California have legal requirement related to reducing GHG emissions and the targets are set out in the DEIS. And, Rogue Climate has been an active participant in organizing support for and shaping legislation and rules policies in Oregon that require

or incentives the reduction of GHG emissions from the consumption of natural gas. Moreover, all of the states have or are engaged in major policy making regarding the future of gas distribution and decarbonizing energy services provided by natural gas utilities. See for example, WUTC docket U-210553, OPUC docket UM 2187, and CPUC docket 20-01-007.

FERC's approval of this project will, for all practical purposes, re-write the current goals and policies and plans in Oregon, Washington and California because GTN's application is directly inconsistent with their intent to reduce GHG emissions. Thus, FERC's decision will impinge upon the states' legitimate rights to protect public health and safety and welfare in violation of the Tenth Amendment of the United States Constitution. Rogue Climate will further develop this argument in its supplemental protest (including its standing to demand the right of Oregon to be a laboratory of policy in this gravest of public welfare issues facing us and next generations) but these conflicts must be discussed and potentially resolved according to NEPA policy:

> Where an inconsistency exists, the statement should describe the extent to which the agency would reconcile its proposed action with the plan or law. While the statement should discuss any inconsistencies, NEPA does not require reconciliation.

Id.

Before issuing the FEIS, FERC should convene and host an opportunity for state cooperation and should, thereby being informed of the inconsistent state policies, set them out in an Amended DEIS and describe its efforts to reconcile them.

CONCLUSION

Despite the deficiencies, Rogue Climate joins the EPA's acknowledgment of FERC's progress in this case in providing the critical GHG analysis - including the downstream emissions information and the social cost of carbon analysis. Such information was not available to inform public comment in most of the prior XPress cases. This information should be enough to make an

informed decision and to allow for informed comments to deny GTN project. However, FERC must move the ball further forward.

Now is the time for FERC to cease its pattern and practice of shirking its NEPA responsibilities, declaring that the characterization of GHG environmental impacts is only required by its application of its Certificate Policy later when the Commission speaks. The NEPA process is separate and merely informs the later decision and requires the GHG analysis. Now is the time for FERC to cease its pattern and practice of shirking its NEPA duties, declaring it cannot act/does not know what to do about GHG impacts because it has not completed its rule making proceeding to amend its Certificate Policy. The NEPA rules have been written. Now is the time for FERC to use its authority to determine that 3,890,000 additional tons of GHGs costing over 12 billion dollars in damages to the environment, captive energy users, communities, landowners is "significant" so that alternative means to meet the unanalyzed need may be proposed and considered. And, ultimately this case presents the legal and factual basis to deny one of TC Energy's XPress projects in order to stop its exploitation.

Respectfully submitted, August 22, 2022,

/s/ Tonia Moro
Tonia Moro
Attorney for Rogue Climate

Composite Exhibit 2

Intermountain Natural Gas

Intermountain Natural Gas 2019 Integrated Resources Plan

Image of Intermountain Natural Gas System

Image of Snip from EBB

Intermountain Gas Company

Integrated Resource Plan

2019 – 2023

October 2019

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Overview

Executive Summary

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and electric power peaking plants, all rely on natural gas to provide an economic, efficient, environmentally friendly, comfortable form of heating energy. Intermountain Gas Company (Intermountain, IGC, or Company) endorses and encourages the wise and efficient use of energy in general and, in particular, natural gas for high efficient uses in Idaho and Intermountain's service area.

Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of this planning process. The demand forecasting and resource decision making process is ongoing. This Integrated Resource Plan (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 impacting areas covered by this plan. Rather, this document is meant to describe the currently anticipated conditions over the five-year planning horizon, the anticipated resource selections and the process for making resource decisions. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

About the Company

Intermountain Gas, a subsidiary of MDU Resources Group, Inc., is a natural gas local distribution company that was founded in 1950. The Company served its first customer in 1956. Intermountain is the sole distributor of natural gas in southern Idaho. Its service area extends across the entire breadth of southern Idaho, an area of 50,000 square miles, with a population of roughly 1,344,000. At the end of 2018, Intermountain served 364,512 customers in 75 communities through a system of over 12,800 miles of transmission, distribution and service lines. In 2018, over 720 million therms were delivered to customers and over 300 miles of transmission, distribution and service lines were added to accommodate new customer additions and maintain service for Intermountain’s growing customer base.

Customer Base

The economy of Intermountain’s service area is based primarily on agriculture and related industries. Major crops are potatoes, milk and sugar beets. Major agricultural-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and service to two major markets: the residential/commercial market and the large volume market. The Company’s residential and commercial customers use natural gas primarily for space and water heating. Intermountain’s

large volume customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications. Large volume demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. During 2018, 50% of the throughput on Intermountain's system was attributable to large volume sales and transportation.

The IRP Process

Intermountain's Integrated Resource Plan is assembled by a talented cross-functional team from various departments within the Company. This five-year forecast is continually updated within the Company and filed with the Commission every two years. It helps to ensure that Intermountain will be able to continue to provide safe and reliable service while minimizing energy costs. The IRP considers all available resources to meet the needs of Intermountain's customers on a consistent and comparable basis. A high-level overview of the process is described below. Each step in the process will be outlined in greater detail in later sections of this document.

Demand

As a starting point, Intermountain develops base case, high growth, and low growth scenarios to project the customer demand on its system.

For the core market, the first step involves forecasting customer growth for both residential and commercial customers. Next, Intermountain develops design weather. Then the Company determines the core market usage per customer using historical usage, weather and geographic data. The usage per customer number is then applied to the customer forecast under design weather conditions to determine the core market demand.

To forecast both therm usage and contract demand for large volume customers, the Company analyzes historical usage, economic trends, and direct input from large volume customers. This approach is appropriate given the small population size of these customer classes. Because large volume customers typically use natural gas for industrial processes, weather data is not generally considered.

Both core market and large volume demand forecasts are developed by areas of interest (AOI) and then aggregated to provide a Total Company perspective. Analyzing demand by AOI allows the Company to consider factors specifically related to a geographic area when considering potential capacity enhancements.

Supply & Delivery Resources

After determining customer demand for the five-year period, the Company identifies and reviews currently available supply and capacity resources. Additionally, the Company includes in its resource portfolio analysis various non-traditional resources as well as potential savings resulting from its energy efficiency program.

Optimization

The final step in the development of the IRP is the optimization modeling process which matches demand against supply and deliverability resources by AOI and for the entire Company to identify any potential deficits. Potential capacity enhancements are then analyzed to identify the most cost effective and operationally practical option to address potential deficits. The Planning Results Section shows how all deficits will be met over the planning horizon of the study.

Intermountain Gas Resource Advisory Committee

To enhance the Integrated Resource Plan development, the Company established the Intermountain Gas Resource Advisory Committee (IGRAC). The intent of the committee is to provide a forum through which public participation can occur as the IRP is developed.

Advisory committee members were solicited from across Intermountain's service territory as representatives of the communities served by Intermountain. Exhibit 1, Section A, is a sample of the initial invitation to join the committee. Committee members have varied backgrounds in regulation, economic development, and business. A full listing of IGRAC members is included in Exhibit 1, Section A.

Intermountain held meetings across its service territory to ensure travel would not impact the ability of committee members and the public to participate. Three meetings were held during the IRP process at the following locations: Boise, Twin Falls, and Idaho Falls. Included in Exhibit 1, Section B and C are sample invitations, sign in sheets and agendas from the meetings, along with copies of the presentations.

After each meeting, for members who were unable to attend, an email containing the materials covered was sent out. The Company provided a comment period after each meeting to ensure feedback was timely and could be incorporated into the IRP. Intermountain also established an email account where feedback and information requests could be managed.

Summary

Through the process explained above, Intermountain analyzed residential, commercial and large volume demand growth and its consequent impact on Intermountain's distribution system using design weather conditions under various scenarios. Forecast demand under each of the customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of potential delivery deficits, both from a total Company perspective as well as an AOI perspective. The resources needed to meet these projected deficits were analyzed within a framework of traditional, non-traditional and energy efficiency options to determine the most cost effective and operationally practical means available to manage the deficits. In utilizing these options, Intermountain's core market and firm transportation customers can continue to rely on uninterrupted firm service both now and in the future.

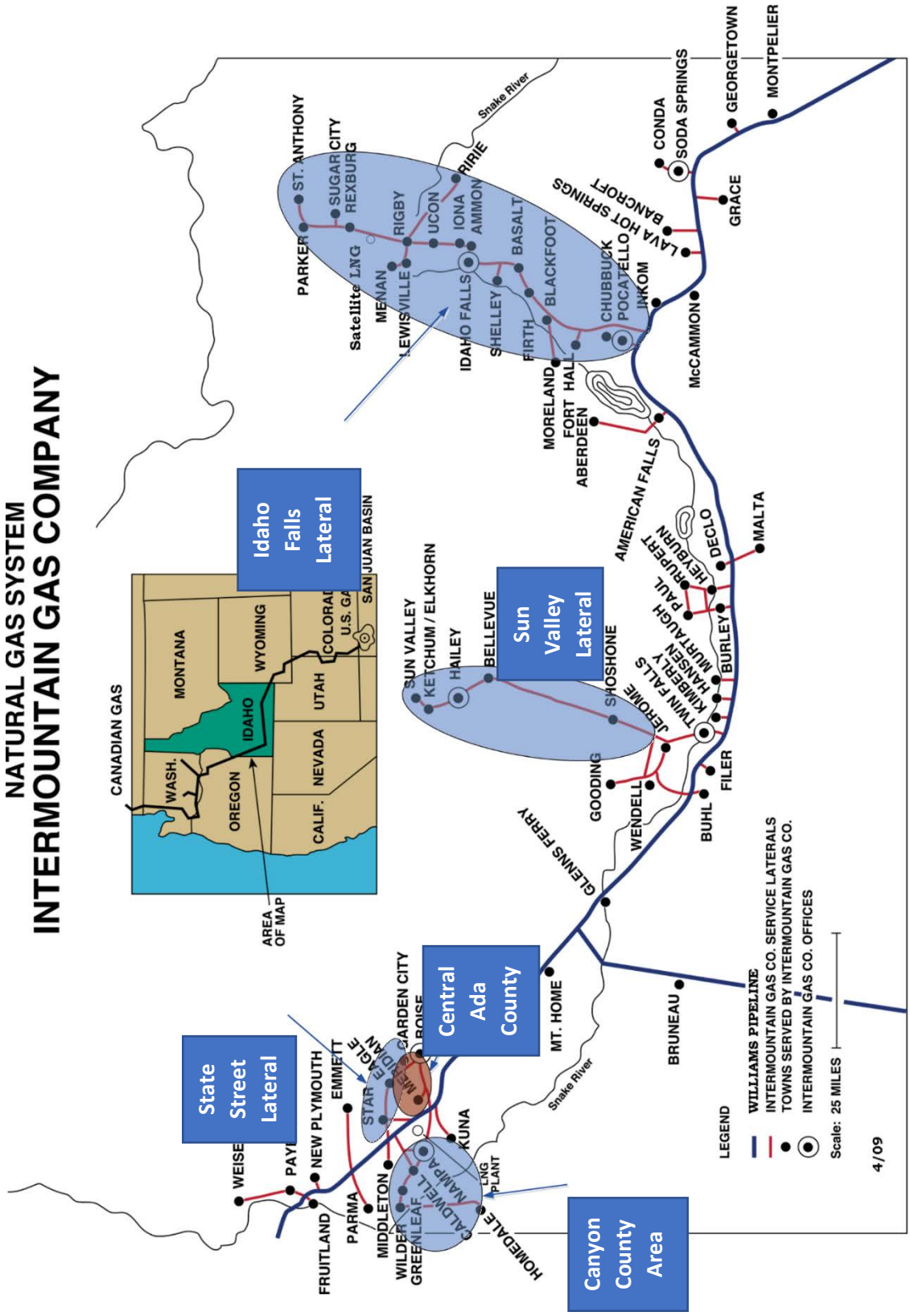


Figure 1: Intermountain Gas System Map

About the Natural Gas Industry

Natural Gas and the National Energy Picture

The blue flame. Curling up next to a natural gas fireplace, starting the morning with a hot shower, coming home to a warm house. The blue flame of natural gas represents warmth and comfort, and provides warmth and comfort in the cleanest, safest, most affordable way possible.

Natural gas is the cleanest fossil fuel. Natural gas burns efficiently, producing primarily heat and water vapor. The Northwest Gas Association has reported that natural gas produces about 45% less carbon dioxide than burning coal, 30% less than oil and 15% less than wood. In addition, according to the American Gas Association, households with natural gas versus all electric appliances produce 41% less greenhouse gas emissions.

Natural gas is the safest form of energy. According to the Department of Transportation, pipelines are the safest form of energy transportation.

Natural gas is affordable. Over the last decade, the price of natural gas fell by about 37% (adjusted for inflation). According to the Northwest Gas Association, households that use natural gas for heating, cooking and clothes drying spend an average of $874 less per year than homes using electricity for those same applications. The American Gas Association has reported that for residential customers, the cost of natural gas has been lower than the cost of propane, fuel oil, or electricity since 2010, and is forecasted to stay low through 2040.

Consumers benefit from the use of natural gas in two ways: directly and indirectly. Using natural gas to warm your home, heat your water, cook your meal, dry your clothes or fuel your fireplace, is the direct use of natural gas. The Northwest Gas Association has reported that the direct use of natural gas is about 92% efficient.

According to the American Gas Association, in the United States natural gas currently meets more than 25% of the nation's energy needs, providing energy to more than 75 million residential, commercial and industrial customers. The residential market is comprised of approximately 69 million homes and represents 18% of total U.S. natural gas consumption. Approximately 5.5 million commercial customers make up 13% of total U.S. natural gas consumption. Roughly 185,400 industrial and manufacturing sector customers use natural gas in their processes, consuming 32% of the U.S. annual total.

Consumers also benefit from the use of natural gas in a much less obvious way through the indirect use of natural gas. The most common application of indirect use is using natural gas for electric generation. According to the Northwest Gas Association, as much as 35% of the natural gas end use market is for electric generation. The indirect us of natural gas is less efficient than direct use as it provides only 32% of the energy as heat by the time it reaches a customer's home or business. However, the U.S. Energy Information Administration (EIA) has reported that natural gas used for electric generation has allowed U.S. power plants to achieve a 27-year low in

emissions. In fact, according to the Northwest Gas Association, natural gas emits up to 56% fewer greenhouse gasses than coal for the same amount of electricity.

Natural gas is now even more plentiful in North America, with an estimated 100 years supply at current consumption levels. Even with this plentiful supply, and lower, more stable prices, it remains vital that all natural gas customers use the energy as wisely and as efficiently as possible.

The Direct Use of Natural Gas

The direct use of natural gas refers to employing natural gas at the end-use point for space heating, water heating, and other applications, as opposed to using natural gas to generate electricity to be transmitted to the end-use point and then employed for space or water heating. As discussed earlier, the direct use of natural gas achieves 92% energy efficiency and makes economic sense in today's energy era.

As electric generating capacity becomes more constrained in the Pacific Northwest, additional peak generating capacity will primarily be natural gas fired. Direct use will mitigate the need for future generating capacity. If more homes and business use natural gas for heating and commercial applications, then the need for additional generating resources will be reduced. At times of excess capacity, water storage normally used for generating power, can be released for additional irrigating, aquifer recharging, fish migration, and navigation uses.

From a resource and environmental perspective, the direct use of natural gas makes the most sense. More energy is delivered using the same amount of natural gas, resulting in lower cost and lower CO_2 emissions. This direct, and therefore, more efficient natural gas usage will serve to keep natural gas prices, as well as electricity prices, lower in the future.

Intermountain plays a critical role in providing energy throughout southern Idaho. The Company has approximately 330,000 residential customers which use roughly 165.6 million therms a year for space heating. If this demand had to be served by electricity, it would mean that Intermountain's residential customers would require approximately 3,787,069 megawatt hours a year to replace the natural gas currently used to heat their homes.

According to its 2018 Annual Report, Idaho Power's total annual residential megawatt hour sales for 2018 were 5,135,000. If the aforementioned 330,000 residential customers used electric space heat instead of natural gas, Idaho Power's total residential sendout would rise to 8,922,069 mWh, a 73.8% increase, requiring considerable additional generation and transmission facilities.

In peak terms, if these 330,000 customers had electric furnaces with 25kw capacity, and just 1/3 of them were operating simultaneously during a cold-weather winter peak, there would be an additional winter peak load of 2,750 megawatts. According to Idaho Power's Annual Report, it recently experienced a January 2017 winter peak load of 2,527 megawatts. Without the direct use of natural gas to heat these 330,000 homes, Idaho Power's winter peak load could reach 5,277 megawatts, a 109% increase! This additional 2,750-megawatt peak load would be the

equivalent of approximately nine 300-megawatt natural gas-fired electric generating facilities, like Langley Gulch, all running at full capacity. A substantial increase in transmission facilities would also be required to handle this peak load, since it would be well above the Idaho Power record Summer peak from July 2017 of 3,422 megawatts.

Ultimately, promoting and using natural gas for direct use in heating applications is the best use of the resource, and mitigates the need for costly generation and infrastructure expansion across the U.S. electric grid.

Demand

Demand Forecast Overview

The first step in resource planning is forecasting future load requirements. Three essential components of the load forecast include projecting the number of customers requiring service, forecasting the weather sensitive customers' response to temperatures and estimating the weather those customers may experience. To complete the demand forecast, contracted maximum deliveries to industrial customers are also included.

Intermountain's long range demand forecast incorporates various factors including divergent customer forecasts, statistically based gas usage per customer calculations, varied weather profiles and banded natural gas price projections; all of which are discussed later in this document. Using various combinations of these factors results in six separate and diverse demand forecast scenarios for the weather sensitive core market customers.

Combining those projections with the large volume market forecast provides Intermountain with six total company demand scenarios that envelop a wide range of potential outcomes. These forecasts not only project monthly and annual loads but also predict daily usage including peak demand events. The inclusion of all this detail allows Intermountain to evaluate the adequacy of its supply arrangements and delivery under a wide range of demand scenarios.

Intermountain's resource planning looks at distinct segments (i.e. AOIs) within its current distribution system. After analyzing resource requirements at the segment level, the data is aggregated to provide a Total Company perspective. The AOIs for planning purposes are as follows:

- The Canyon County Area (CCA), which serves core market customers in Canyon County.
- The Sun Valley Lateral (SVL), which serves core market customers in Blaine and Lincoln counties.
- The Idaho Falls Lateral (IFL), which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties.
- The Central Ada County (CAC), which serves core market customers in the area of Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west.
- The State Street Lateral (SSL), which serves core market customers in the area of Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21.
- The All Other segment, which serves core market customers in Ada County not included in the State Street Lateral and Central Ada Area, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties.

Residential & Commercial Customer Growth Forecast

This section of Intermountain's IRP describes and summarizes the residential and commercial customer growth forecast for the years 2019 through 2023. This forecast provides the anticipated magnitude and direction of Intermountain's residential and commercial customer growth by the identified Areas of Interest for Intermountain's current service territory. Customer growth is the primary driving factor in IGC's five-year demand forecast contained within this IRP.

IGC's customer growth forecast includes three key components:

1. Residential new construction customers,
2. Residential customers who convert to natural gas from an alternative fuel, and
3. Commercial customers

To calculate the number of customers added each year, the annual change in households for each county in the Company's service territory is determined using the Idaho Economics Summer 2018 Economic Forecast for the State of Idaho by John S. Church ('18 Forecast), dated October 2018 (see Exhibit 2, Section A). Using the assumption that a new household means a new dwelling is needed, the annual change in households by county is multiplied by Intermountain's market penetration rate in that region to determine the additional residential new construction customers. Next, that number is multiplied by the IGC conversion rate, which is the anticipated percentage of conversion customers relative to new construction customers in those locales. This results in the number of expected residential conversion customers, which when added to the residential new construction numbers, equals the total expected additional residential customers by county.

To accurately estimate growth for the State Street AOI, which contains a small portion of Canyon County and a large portion of Ada County, an additional estimate is utilized. The Community Planning Association of Southwest Idaho (COMPASS) conducts annual forecasts based on defined 'Traffic Analysis Zones' (TAZ) within Ada County. According to COMPASS, the TAZ that coincides with the State Street AOI boundary is expected to grow 3.14% per year over the next 5 years. This annual growth rate is applied to the current customer count within that boundary to derive the estimated growth of the State Street AOI over the same time period.

The Central Ada AOI sits entirely in Ada County. Using the same methodology as described above, the Central Ada AOI growth was calculated to be 2.9% per year.

The residential new construction numbers by county are multiplied by the IGC commercial rate, which is the anticipated percentage of commercial customers relative to residential new construction customers in those locales, to arrive at the number of expected additional commercial customers.

With the continued resurgence in the housing market, Intermountain growth projections are up considerably, when compared to the 2017 IRP. The '18 Forecast household numbers are

employed to determine the relative overall number of customer additions, as well as the distribution of those customer additions across the Company's service territory.

The following graph depicts the relationship, or shape, of customer additions by AOI:

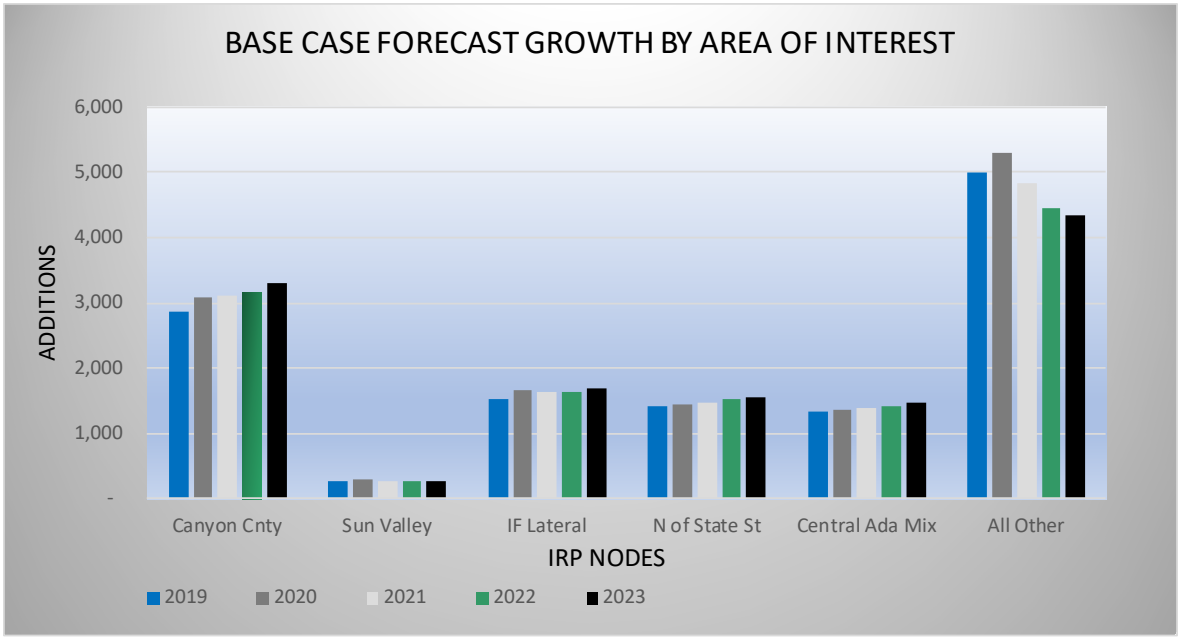


Figure 2: Base Case Forecast Growth by Area of Interest

The '18 Forecast contains three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model and has developed three five-year core market customer growth forecasts. The following graph shows the annual additional customers forecast for each of the three economic scenarios.

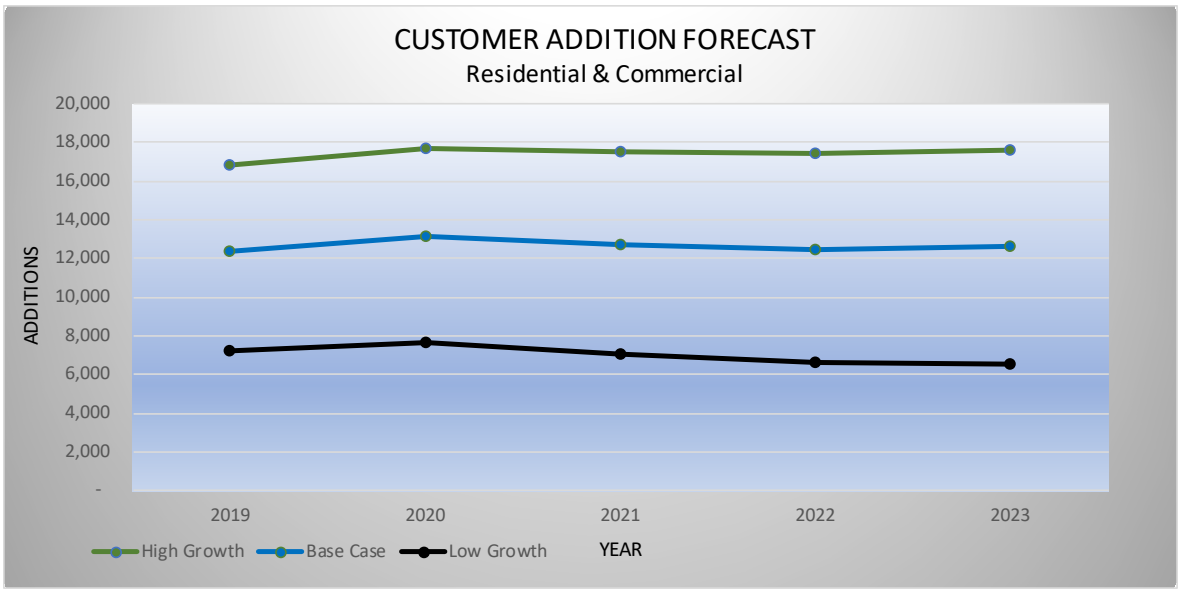


Figure 3: Customer Addition Forecast – Residential & Commercial

The following graph shows the difference in base case annual additional customers between the 2017 and 2019 IRP forecast years common to both studies:

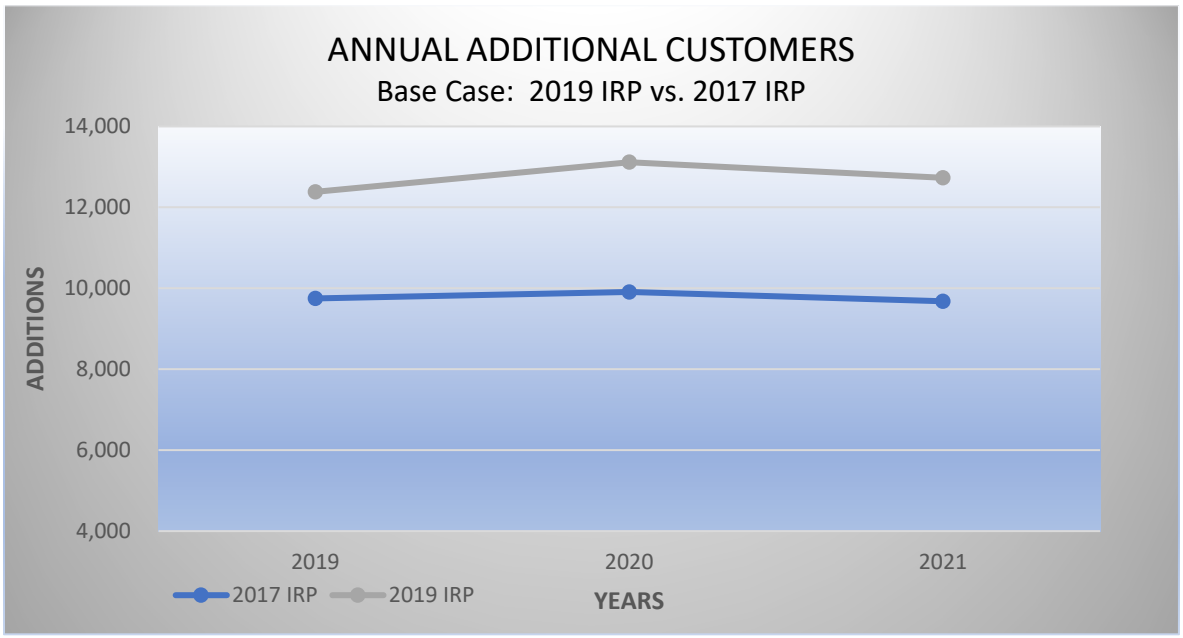


Figure 4: Annual Additional Customers – Base Case: 2019 IRP vs. 2017 IRP

As indicated, the economic recovery and its resulting positive impact on housing and business growth has resulted in a much increased IGC customer growth forecast in the years common to the 2017 and 2019 IRP's.

The following tables show the results from the five-year customer growth model for each scenario for the annual additional or incremental customers and total customers at each year-end.

Table 1: Forecast New Customers

Forecast New Customers					
	2019	2020	2021	2022	2023
LOW GROWTH	7,197	7,655	7,072	6,605	6,528
BASE CASE	12,384	13,115	12,733	12,490	12,642
HIGH GROWTH	16,792	17,722	17,492	17,412	17,610

Table 2: Forecast Total Customers

Forecast Total Customers					
	2019	2020	2021	2022	2023
LOW GROWTH	371,582	379,237	386,309	392,914	399,442
BASE CASE	376,769	389,883	402,616	415,106	427,748
HIGH GROWTH	381,177	398,899	416,391	433,803	451,412

The following sections explore, more fully, the different components of the customer forecast, including the '18 Forecast, market penetration and conversion rates, and commercial customer growth.

Household Projections

The '18 Forecast provides county by county projections of output, employment and wage data for 21 industry categories for the state of Idaho, as well as population and household forecasts. This simultaneous equation model uses personal income and employment by industry as the main economic drivers of the forecast. The model also utilizes forecasts of national inputs and demand for those sectors of the Idaho economy having a national or international exposure. Industries that do not have as large of a national profile and are thus serving local communities and demand are considered secondary industries. Local economic factors, rather than the national economy determine demand for these products.

The '18 Forecast uses two methods for population projections: (1) a cohort-component population model in which annual births and deaths are forecast, the net of which is either added to or subtracted from the population; and (2) an econometric model which forecasts population as a function of economic activity. The two forecasts are then compared and reconciled for each quarter of the forecast. Migration into or out of the state is derived as a result of this reconciliation.

As previously mentioned, the '18 Forecast provides three scenarios: (1) base case, (2) high growth, and (3) low growth. The base case scenario assumes a normal amount of economic fluctuation, a normal business cycle. This becomes the standard against which changes in customer growth, as affected by the low and high growth scenarios can be measured.

The Base Case Economic Growth Scenario

In the base case scenario of the Summer 2018 Idaho Economic Forecast it is projected that Idaho will continue to be an attractive environment for population and household growth. In the decade of the 1990s Idaho's population increased at an annual average rate of 2.5 % per year. The 2008 national recession brought about a significant decline in Idaho's nonagricultural employment over the 2000 to 2010 period and a slowing of the rate of population growth in the state—slowing to an annual average rate of 1.9 % per year over the decade. Nevertheless, that rate of population growth was higher than Idaho's annual average rate of natural population growth (births minus deaths) of nearly 1.0 % per year indicating that Idaho continued to attract an in-migration of population even during that period of tough economic times.

Recent statistics indicate that Idaho's economy and population growth have again regained momentum. In 2016, Idaho was ranked as the third fastest growing state in the nation with an annual increase of 1.83%. In 2017, Idaho's population growth accelerated to an annual gain of 2.2% and was ranked as the fastest growing state in the nation (an absolute gain of nearly 37,000 persons). The population growth has not been equally distributed across the state. Since the 2010 US Census through mid-year 2017, it is estimated that Idaho's population has increased by nearly 149,400. Nearly 62.5% of those population gains were posted in the Treasure Valley with Ada and Canyon counties accounting for 93,200 of the state's population growth. The counties along the Idaho Falls Lateral in eastern Idaho have posted a population gain of nearly 17,800 since the 2010 Census; 11.9% of the overall population growth in the state. The Magic Valley counties posted a gain of 10,300 in population since the last census, and accounted for 6.9% of the state's overall population growth.

It is projected that during the 25-year period 2015 to 2040 that Idaho's population will increase by 906,700 reaching a total population of 2,559,500 by the year 2040—an annual average pace of 1.8% per year. The number of households in the state is expected to increase at a slightly faster pace of 2.1% per year over the 2015 to 2040 period adding nearly 423,400 additional households statewide. Ada and Canyon counties are projected to capture the majority of the state's future population and household growth over the 2015 to 2040 period—with a gain of 568,000 persons and 248,200 households. Ada county is projected to see an absolute population increase of 319,000 (150,400 households) over the 2015 to 2040 period.

Canyon county will take up second place statewide with a projected absolute population gain of 249,700 (a 97,900 increase in the number of households). In eastern Idaho, the Bonneville, Madison, Bannock, and Jefferson counties are expected to see increases in population of 54,800; 34,500; 26,300; and 17,900, respectively, over the 2015 to 2040 forecast period. A total growth

in population and households of 140,400 persons and 61,600 households in the eight counties along the Idaho Falls Lateral is forecasted over the 25-year period.

In the base case scenario of the '18 Forecast, it is assumed that the state of Idaho will continue to be an attractive environment for the in-migration of new business. In spite of the employment losses that the state experienced in the 2008 economic downturn, Idaho's industries have regained economic traction and have continued their expansion within the state. Another dynamic that has been examined by the Federal Reserve Bank of San Francisco is an exodus of population and some businesses from the state of California. While California's population numbers continue to increase, the annual average rate of population growth in California is less than the state's natural rate of population growth (births minus deaths). This fact indicates that California is experiencing an annual net out-migration between 0.2% and 0.3% of its population. Given California's current population of greater than 39,000,000, an annual out-migration of 0.2% to 0.3% translates to 80,000 to 120,000 persons relocating each year. Driver's license surrender statistics from the Idaho Department of Transportation indicate that Idaho is capturing a significant portion of relocating Californians. For many of the businesses relocating from California, a primary reason behind their exodus is the relatively high cost of doing business and the burden of business regulation in California. This forecast views this circumstance as an ongoing phenomenon that is not likely to abate in the near-term and will be a significant factor contributing to economic and population growth in the western states in proximity to California.

Total non-agricultural employment in Idaho is projected to increase by 336,200 (an annual average increase of 1.7% per year) over the 2015 to 2040 period. Again, Ada and Canyon counties are projected to capture the majority of those non-agricultural employment gains with a projected increase of 199,400 non-agricultural jobs, an annual average increase of 2.2% per year. During those 25 years, Ada and Canyon counties are projected to account for 59.2% of the total non-agricultural employment gains statewide.

The counties along the Idaho Falls Lateral (Bannock, Bingham, Bonneville, Butte, Fremont, Jefferson, Madison, and Power) are projected to see an absolute increase in non-agricultural employment of nearly 58,000, an annual average rate of 1.15% per year. In south central Idaho, (Blaine, Camas, Cassia, Gooding, Jerome, Lincoln, Minidoka, and Twin Falls counties) total non-agricultural employment is projected to increase by nearly 27,800 jobs, an annual average pace of 1.1% per year, over the forecast period.

Similar to the economic outlook in the 2017 IRP, Idaho's manufacturing sector will not be the driver of economic growth in the state. Over the 10-year period 2000 to 2010 manufacturing employment in the state decreased by 17,200 jobs. In the five years since 2010 Idaho regained nearly 8,500 of those lost manufacturing jobs.

In the longer term, manufacturing employment in the state is projected to only increase by a modest 5,600 jobs over the 2015 to 2040 period—an annual average gain of 0.8% per year. In Ada and Canyon counties manufacturing employment is projected to increase by nearly 4,800 over the forecast period.

During the historical period, 1990 to 2010, food processing employment in Ada and Canyon counties had been increasing—largely on the strength of job gains in the dairy products manufacturing sector. In the current forecast period, it is expected that the dairy products manufacturing firms will continue to post job gains. At the same time, it is projected that the vegetable processing firms in Ada and Canyon counties will continue to experience further job losses over the forecast period. The total effect of these trends in the food processing industry is that the Company does not project the food processing sector to be a significant contributor to any gains in manufacturing employment in Ada and Canyon counties. However, in south central Idaho, the food processing sector is projected to be the driving factor behind forecasted manufacturing employment gains of nearly 1,100 jobs in the Twin Falls area over the forecast period.

Employment in Idaho's lumber and wood products manufacturing sector slipped in the last recession. Future job gains in the lumber and wood products manufacturing sector is projected to be minimal over the forecast period. Statewide employment in stone, clay, and glass products and fabricated metal products manufacturing is expected to increase in proportion to population and household growth in the state. Idaho's electronics and machinery manufacturing sectors are not expected to regain the jobs lost during the last recession. No new machinery or electronics manufacturing facilities are anticipated to be located in Idaho during the forecast period.

Statewide employment in the transportation, trade, and utilities industries is projected to increase by nearly 28,700 jobs over the forecast period—an annual average increase of 1.0% per year. In general, employment in the transportation, trade, and utilities industries is projected to increase at a pace that is half of the rate of population and household growth statewide. In Ada and Canyon counties, employment in the transportation, trade, and utilities industries is projected to increase by 22,400 over the forecast period—representing 78% of the projected statewide employment gains in the sector. Counties along the Idaho Falls Lateral are projected to see transportation, trade, and utilities jobs increase by 4,300 over the 25-year period—representing 15% of the sector's projected job gains statewide.

Over the forecast period, employment in Idaho's service industries are projected to be the area of the greatest future employment growth in the state. Professional and business services employment statewide is projected to increase by 73,400 over the forecast period—an annual average increase of 2.6% per year. Employment in education and health services is projected to add 75,000 jobs statewide during the forecast period while the leisure and hospitality services sector is projected to add nearly 31,700 jobs. Ada and Canyon County employment in the professional and business services sector is projected to increase by 45,600, representing 62.1% of the projected gains statewide. Similarly, projected employment gains in Ada and Canyon counties in the educational and health services sector, and the leisure and hospitality services sector are projected to add nearly 46,000 jobs (61.3% of the total statewide gain), and 21,800 jobs (68.8% of the projected total statewide gain), respectively, over the forecast period.

Even with the tight fiscal conditions that came with the 2008 national recession, employment in Idaho's government sector increased by nearly 9,800 during the 2000 to 2010 period. Between 2010 and 2015, government employment in the state slowed adding only about 2,000 jobs in the five-year period. However, it is projected that government employment in Idaho will regain some momentum and increase by nearly 18,200 over the 2020 to 2030 period. In the long term, the forecast projects that government employment statewide will increase by 50,800 over the forecast period—an annual average increase of 1.3% per year. Generally, the bulk of the increase on government employment will be in the state and local government area and largely associated with the need for additional local government employees to provide basic services to a forecasted ever-growing population in the state. It is projected that government employment gains of 26,900 over the forecast period in Ada and Canyon counties will represent nearly 53.0% of the projected government job gains statewide.

The High and Low Economic Growth Scenarios

The high growth and low growth scenarios of the '18 Forecast present alternative views of the economic future of Idaho and its 44 counties. The high growth scenario of the '18 Forecast presents a vision of a more rapidly growing economy in Idaho. For example, the high growth scenario produces a projected statewide population of 2,060,323 in the year 2023 versus a base case scenario Idaho population forecast of 1,928,784 in the same year. The high growth scenario average annual compound rate of population growth from 2010 to 2040 is 2.0% per year.

Alternatively, the low growth Scenario of the '18 Forecast presents a slower economic outlook for the Idaho economy. In the low growth scenario, Idaho's 2023 population is projected to reach the much lower level of 1,736,355, exhibiting an annual average compound growth rate of 1.2% per year from 2010 to 2040.

An examination of the possible economic and demographic events that could produce the economic and population growth projected in the high and low growth scenarios are outlined below:

The High Growth Economic Scenario

By the year 2040 the high growth scenario forecasts that population and households in Idaho is projected to be nearly 11.1% higher than the forecasted amounts in the base case scenario. This represents a projected population in the high growth scenario that is nearly 283,900 higher in the state by the year 2040 with an additional 114,100 households over the base case scenario. The projected gap between the high growth and base case scenarios widens in the years 2020-2030 as the Idaho economy regains some of the economic momentum that it established in the years 1990 through 2005. In the high growth forecast it is expected that stronger employment gains statewide will be a magnet for a stronger rate of population in-migration to the state.

In the high growth scenario of the '18 Forecast, Idaho is projected to be a modestly more attractive environment for manufacturing firms. Therefore, in spite of the employment losses that the state experienced in the 2008 recession, Idaho's manufacturing industries are projected to gain employment at a faster rate in the 2015 to 2025 period. In 2025, Idaho's manufacturing

employment is expected to reach 72,200—2,800 jobs higher than the amount projected in the base case forecast. Over the longer term, manufacturing employment in the high growth forecast is projected to exceed the base case scenario by 4.1%, or 2,700 jobs, in the year 2040.

In the high growth forecast, it is assumed the food processing industry does not shed as many jobs at vegetable processing facilities across the state, and Idaho will continue to attract new food processing companies to the state. There are no expectations for the location of a new electronics manufacturing plant in the state as was the case in the high growth forecasts of prior IRPs. It is expected that employment in lumber and wood products manufacturing will continue to remain weak and not be a significant factor for future employment growth. However, the state may pick up some additional manufacturing jobs in machinery and equipment and fabricated metals manufacturing in the high growth scenario. Nevertheless, the prospects for additional employment in these manufacturing sectors will only offset natural productivity gains, and subsequent job attrition in the manufacturing sector. Transportation equipment manufacturing in the state is not expected to benefit from the stronger economic growth forecasted in the high growth scenario.

The Low Growth Economic Scenario

By the year 2040, the low growth forecast of population and households in Idaho is 12.5% lower than the forecasted amounts in the base case scenario. This represents a projected difference of nearly 318,700 fewer people in the state by the year 2040 and nearly 138,800 fewer households. In the low growth scenario, overall employment gains are projected to slow statewide, causing Idaho to be less attractive to a job-seeking population which would otherwise migrate to Idaho.

Idaho's manufacturing employment in the low growth scenario is not forecasted to significantly recover from the 2008 national recession.

In the low growth scenario, the state's loss of jobs in the food processing industry accelerates and nearly 1,500 additional jobs are lost over the forecast period. The potato processing plants in southern Idaho would experience the bulk of these job losses. The low growth scenario assumes that the JR Simplot plant in Caldwell will shed over 1,000 jobs by the year 2020. Furthermore, the sugar processing plants in southern Idaho are projected to feel increased pressure from competition and will find it necessary to close one of the sugar processing plants in either Nampa, Paul, or Twin Falls. The dairy industry and its associated food processing plants are projected to reach a point where no further capacity can be added due to increased population and environmental pressures.

Employment losses in Idaho's lumber and wood products manufacturing industry are projected to accelerate in the low growth scenario. In this scenario, the brunt of these additional losses will be felt in those portions of the wood products industry that are increasingly vulnerable to low-cost foreign produced products (i.e. the woodgrain molding plants in Fruitland and Nampa).

Idaho's electronics and machinery manufacturing industries are expected to experience further job losses in the low growth forecast. Additionally, employment in stone, clay, and glass products and fabricated metal products manufacturing are both projected to be at lower levels of total employment than in the base case scenario.

In general, in the low growth scenario, manufacturing industry employment in the year 2040 is projected to be nearly 6,400 jobs (9.4%) lower than in the base case scenario.

Transportation, trade, and utilities employment in the low growth scenario is projected to have nearly 3,200 fewer jobs (2.0% lower) by the year 2040 than in the base case scenario. Lower overall economic growth projected in the low growth scenario produces lower levels of demand for transportation services and fewer buying opportunities of additional retail stores. Additionally, the low growth scenario projects that there will be closures or downsizing of some of the state's food processing facilities, which all require significant amounts of truck transportation.

The low growth forecast of statewide employment in the finance, insurance, and real estate sector is about 5,700 (14.0%) lower than in the base case scenario by the year 2040. Again, the difference is largely due to the lower levels of population and household growth projected in the low growth scenario.

The outlook for service industry employment in the low growth scenario assumes that employment growth in the service sector will slow, proportionate to the projected slower growth in population and households statewide. Further, Idaho is projected to be less attractive to those service industry firms from outside of Idaho that may have considered relocating all or a portion of their activities to Idaho. Furthermore, the low growth scenario forecasts that Idaho's competitive position for attracting new business will be degraded and that the nearby states of Utah, Oregon, and Nevada will capture a larger proportion of firms making relocation and expansion decisions.

Future government employment in the low growth scenario is projected to be 8.6% (14,800 jobs) lower than the base case scenario by the year 2040. As previously mentioned for other industries, the reason for projected lower levels of government employment in the low growth scenario are the slower rates of population and household growth in the low growth forecast. The low growth scenario projects that the number of assigned military personnel at Mountain Home Airforce Base will remain at levels that are similar to those at the present time.

Forecast Households

As previously stated, the basis for the customer growth forecast relies on the annual variance, or change, in households from year to year, within the counties in which IGC operates. The forecast number of total households; low growth, base case and high growth scenarios, is shown in Table 3.

Table 3: Forecast Total Households – IGC Service Area

Forecast Total Households IGC Service Area					
	2019	**2020**	**2021**	**2022**	**2023**
LOW GROWTH	469,505	477,147	484,232	490,876	497,464
BASE CASE	500,551	513,550	526,193	538,618	551,216
HIGH GROWTH	520,267	537,748	555,041	572,276	589,740

The variance between the common years in the 2017 and 2019 IRPs for forecast total households is depicted in the graph below.

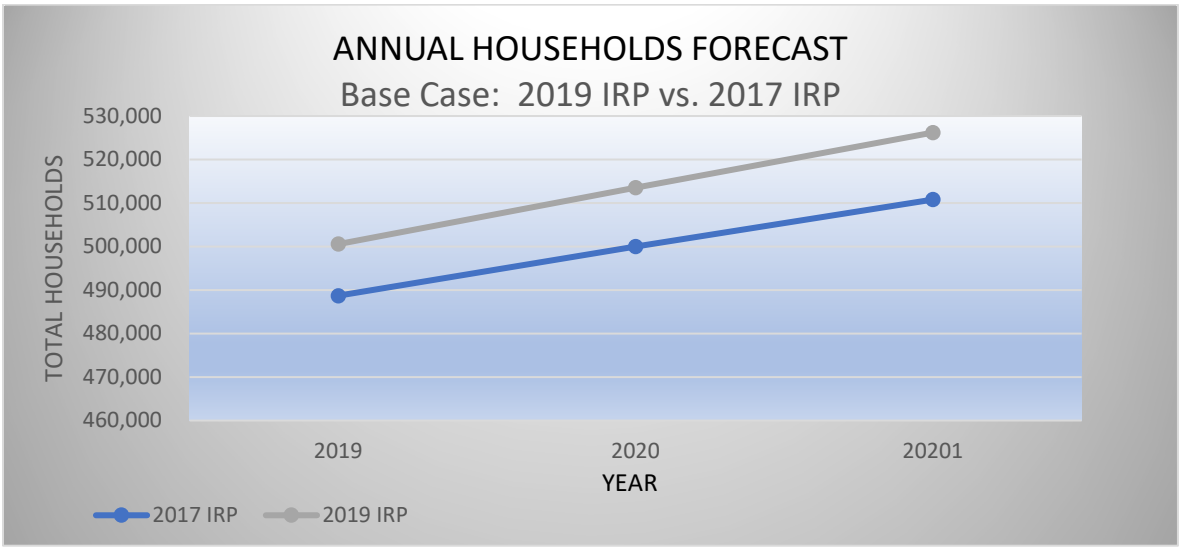


Figure 5: Annual Households Forecast – Base Case: 2019 IRP vs. 2017 IRP

The graph below provides a visual depiction of the variance in household growth for high growth, base case and low growth scenarios for the 23 counties which Intermountain Gas Company serves.

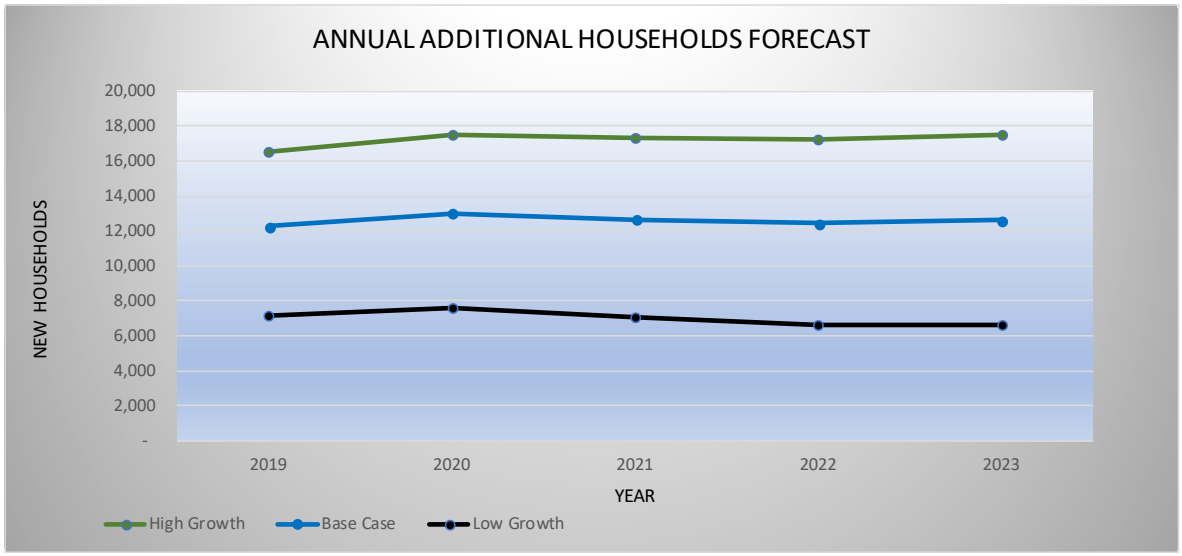


Figure 6: Annual Additional Households Forecast

A comparison of the base case household growth, between the common years in the 2017 and 2019 IRPs, is depicted below.

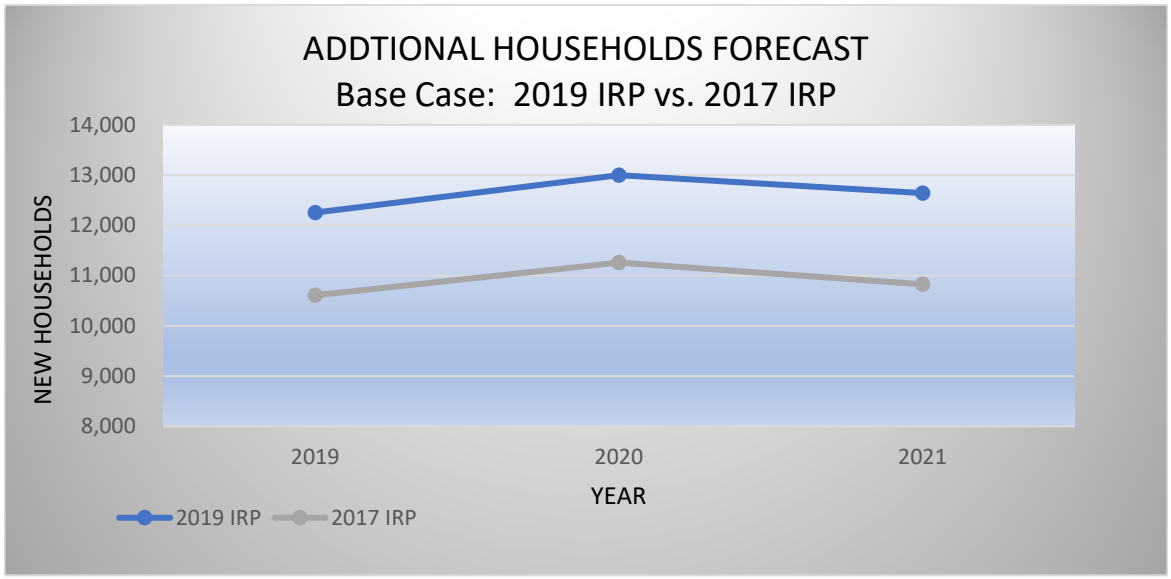


Figure 7: Additional Households Forecast – Base Case: 2019 IRP vs. 2017 IRP

Market Share Rates

IGC utilizes market penetration rates that vary across its service territory. These regional penetration rates are applied to the counties within the Company's service territory within three specific regions: East, Central, and West. These penetration rates are the ratio of IGC's additional residential new construction customers to the total building permits in those regions. The penetration rate is then applied to the forecasted additional households to derive the estimated residential new construction customers by region.

IGC develops market penetration rates by way of the county construction reports which IGC Energy Services personnel use in prospecting for new construction customers. To derive the market penetration rate, the residential new construction customers in the specific areas covered by these reports are divided by the total dwelling permits listed in these reports. In addition, the tracking process includes whether the new home is within reach of existing mainline; i.e., the home can be readily served within IGC's main and service policy without financial contribution by the customer for the extension of service. The areas covered are the jurisdictions/counties within each operation district within the Company's service area which publish monthly building permits. More generally described/identified as: Nampa, Boise, Twin Falls, Pocatello, and Idaho Falls. This data is collected and tracked monthly, by jurisdiction. The cumulative annual penetration rate, by district, is then applied to the household growth forecast per district, to derive the forecast for new construction growth.

The penetration rates used, based on the methodology described above, are depicted in the chart below. Variations in penetration rates across the Company's service area is a function of the variation in population density across the 23 counties which IGC serves in relation to the service area within those counties.

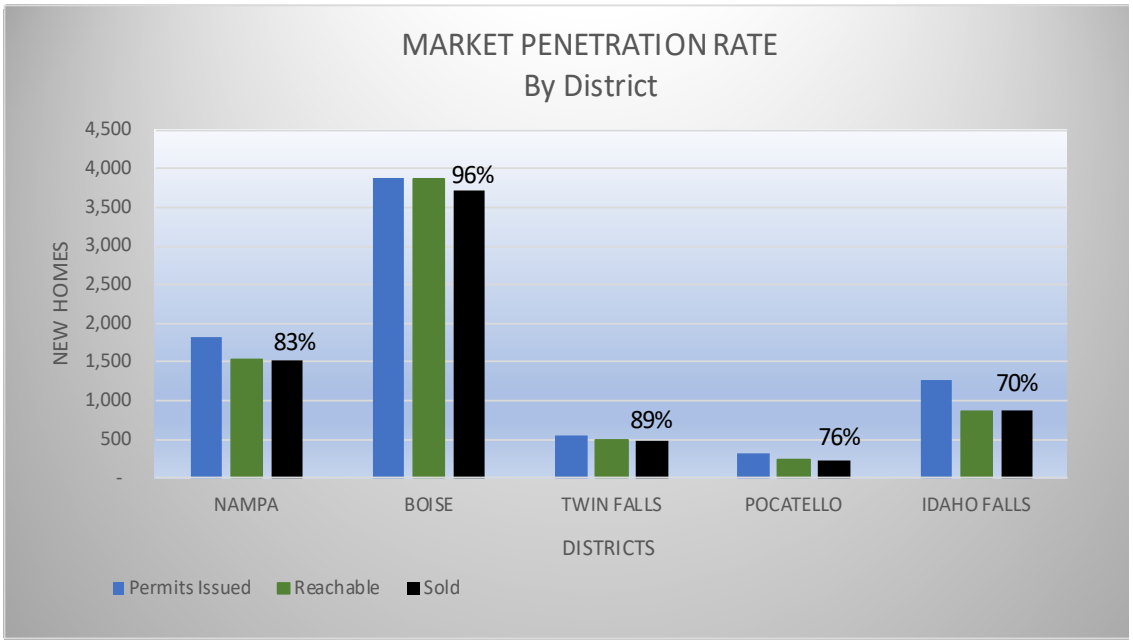


Figure 8: Market Penetration Rate – By District

The following graph illustrates the relationship between the three economic scenarios for the annual residential new construction growth forecast for 2019 – 2023:

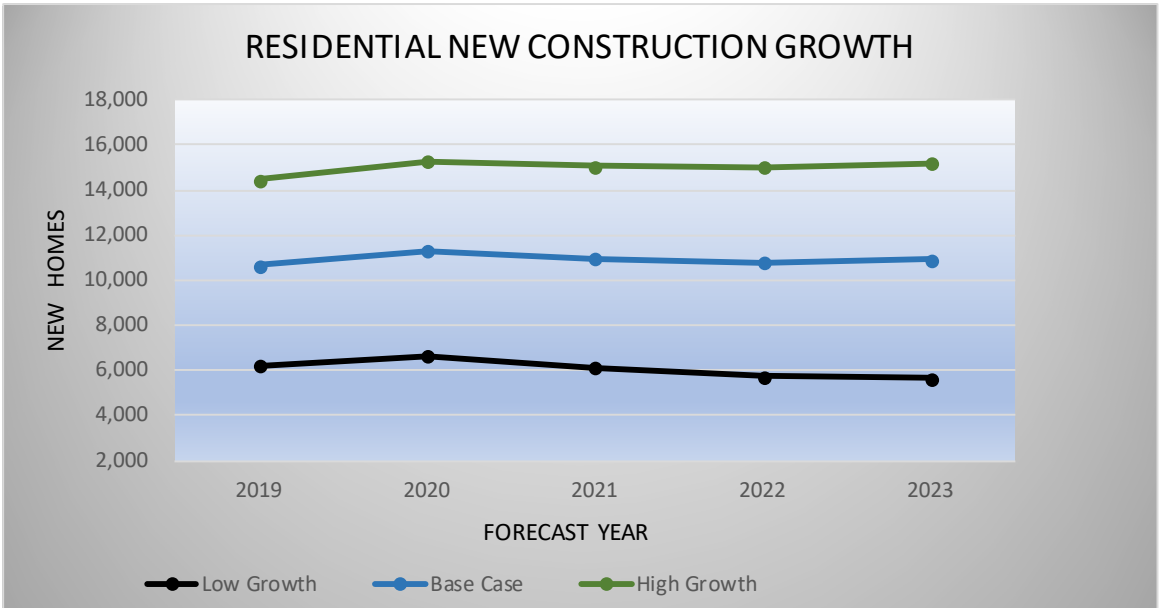


Figure 9: Residential New Construction Growth

The following graph shows the difference in base case residential new construction customer growth between the 2017 and 2019 IRP forecast years common to both studies:

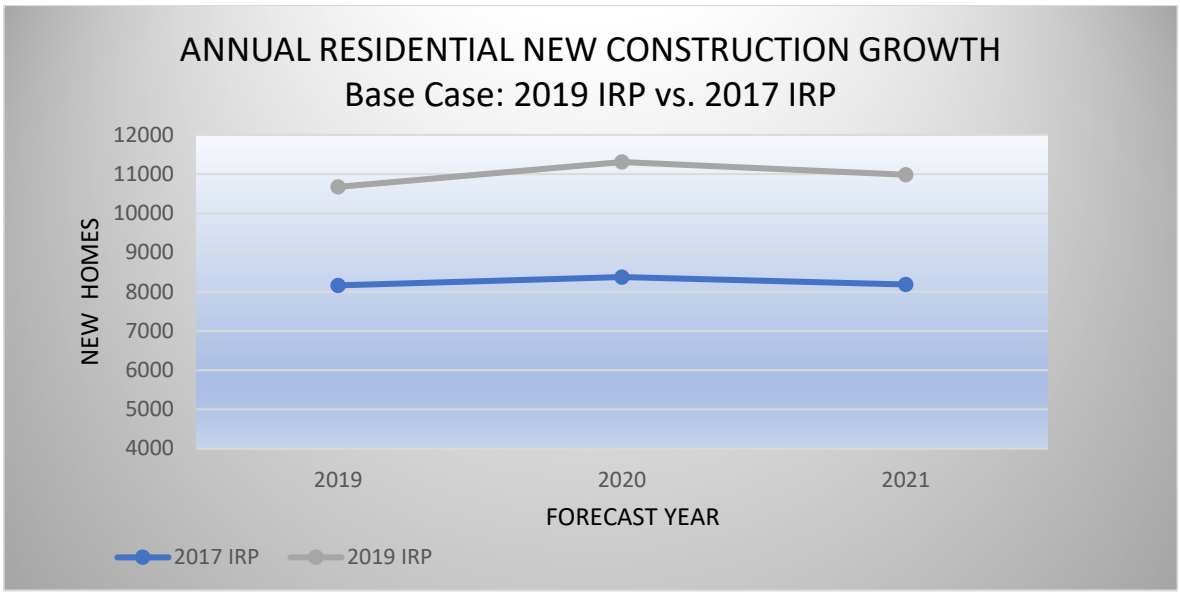


Figure 10: Annual Residential New Construction Growth – Base Case: 2019 IRP vs. 2017 IRP

Conversion Rates

The conversion market represents another source of customer growth for the Company. IGC acquires these customers when homeowners replace an electric, oil, coal, wood, or other alternate fuel source furnace/water heater with a natural gas unit. IGC forecasts these customer additions by applying regional conversion rates based on historical data and future expectations. The following table shows, by region, the assumed conversion rates used in the IRP. These rates represent the percentage of new customer additions which will be conversions. The calculated conversion forecast is then added to the new construction forecast to derive the total residential growth forecast.

The table below illustrates the conversion rates used in the 2019 and 2017 IRPs.

Table 4: Regional Conversion Rate

Regional Conversion Rate		
	2019	**2017**
EASTERN REGION	7%	9%
CENTRAL DIVISION	20%	21%
WESTERN REGION	19%	23%

The following graph illustrates the relationship between the three economic scenarios for the annual residential conversion growth forecast for 2019 – 2023:

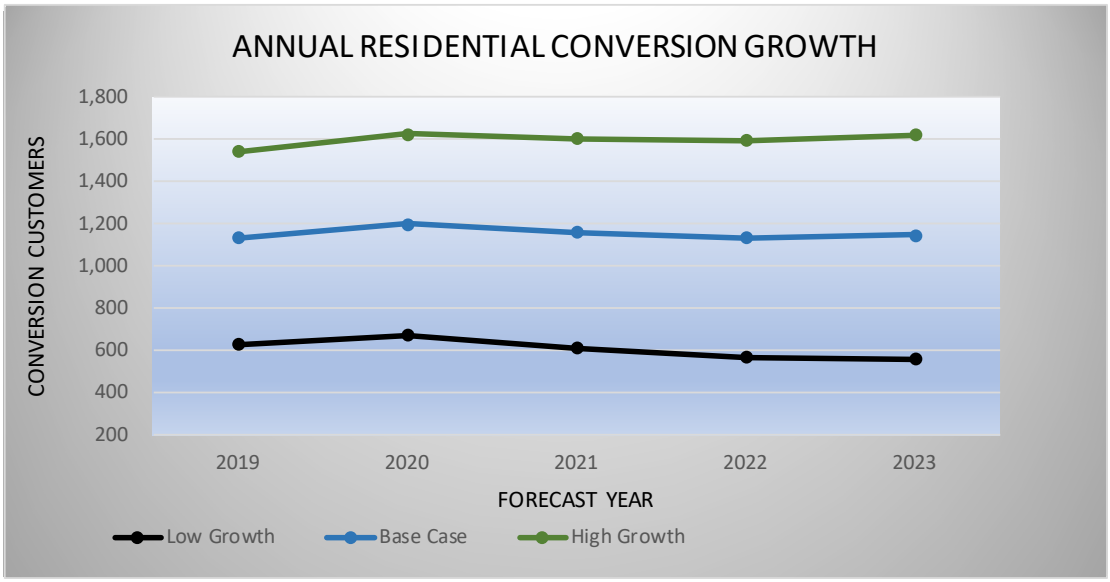


Figure 11: Annual Residential Conversion Growth

The following graph shows the difference in the base case forecast of residential conversion customer growth between the 2017 and 2019 IRP forecast years common to both studies:

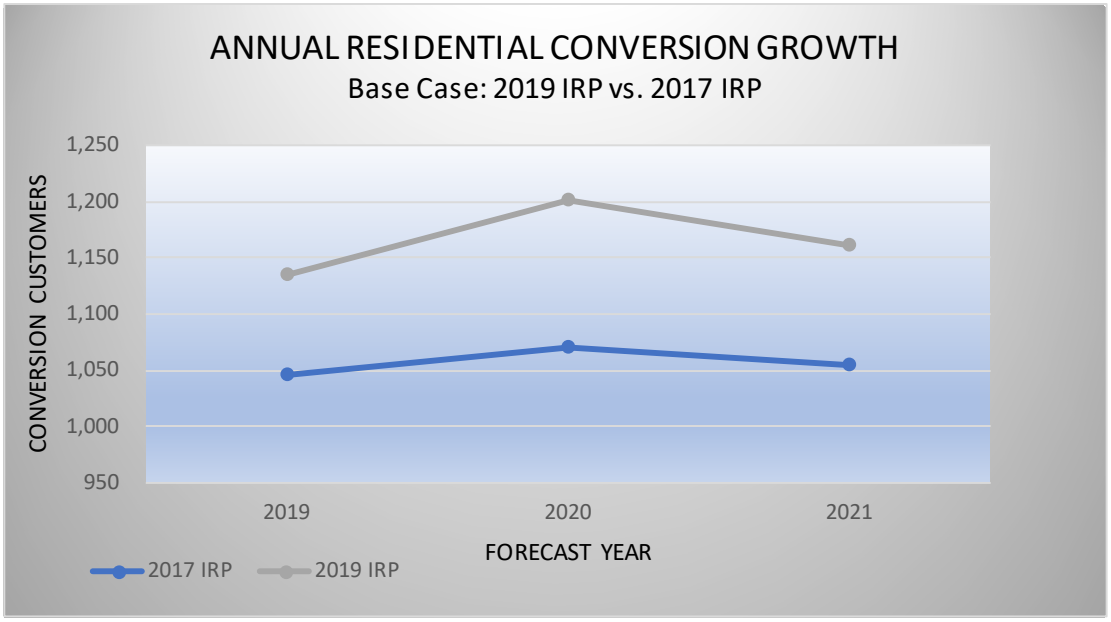


Figure 12: Annual Residential Conversion Growth – Base Case: 2019 IRP vs. 2017 IRP

Commercial Customer Forecast

Commercial customer growth is forecast as a certain proportion of new construction customer additions based on the idea that new households require additional new businesses to serve them. Based on the most recent three-year sales data, the ratio of commercial customer growth to residential growth for the west, central, and east regions was 4.80%, 8.12%, and 5.83%, respectively. Therefore, regional ratios of 5% for the west, and 8% for central, and 6% for the east are used in the base case, high growth, and low growth scenarios. The table below illustrates the variation in this variable from the previous IRP.

Table 5: Commercial Rate Factor

Commerical Rate Factor		
	2019	**2017**
EASTERN REGION	5.83%	11.21%
CENTRAL DIVISION	8.12%	10.36%
WESTERN REGION	4.80%	5.06%

The following graph shows the forecast annual additional commercial customers for the low growth, base case and high growth scenarios from the '18 Forecast.

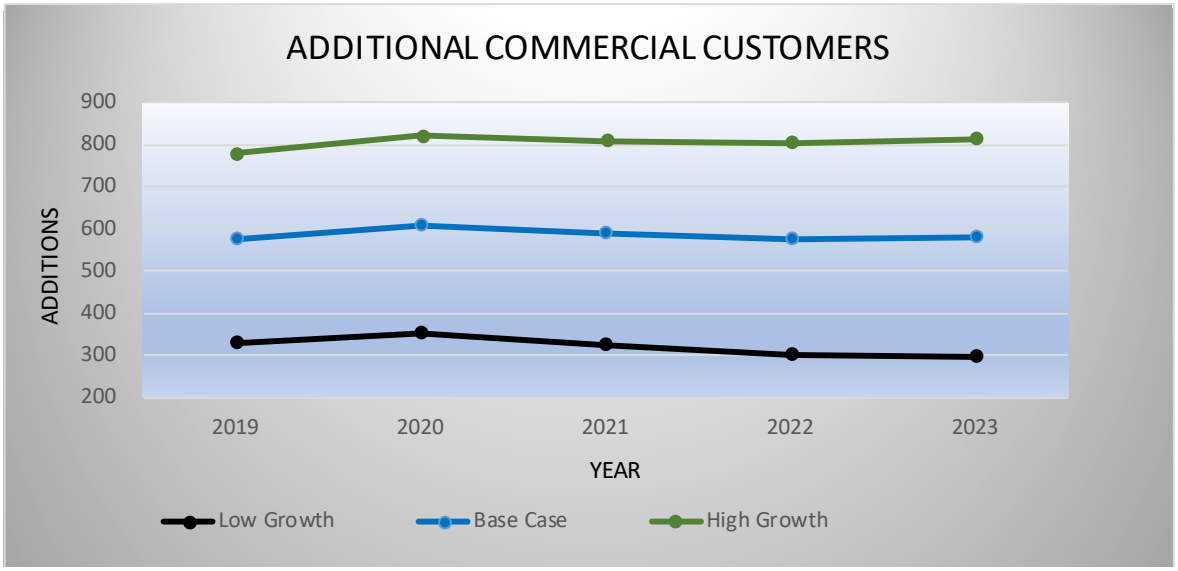


Figure 13: Additional Commercial Customers

The following graph shows the difference in base case commercial customer growth between the 2017 and 2019 IRP forecast years common to both studies:

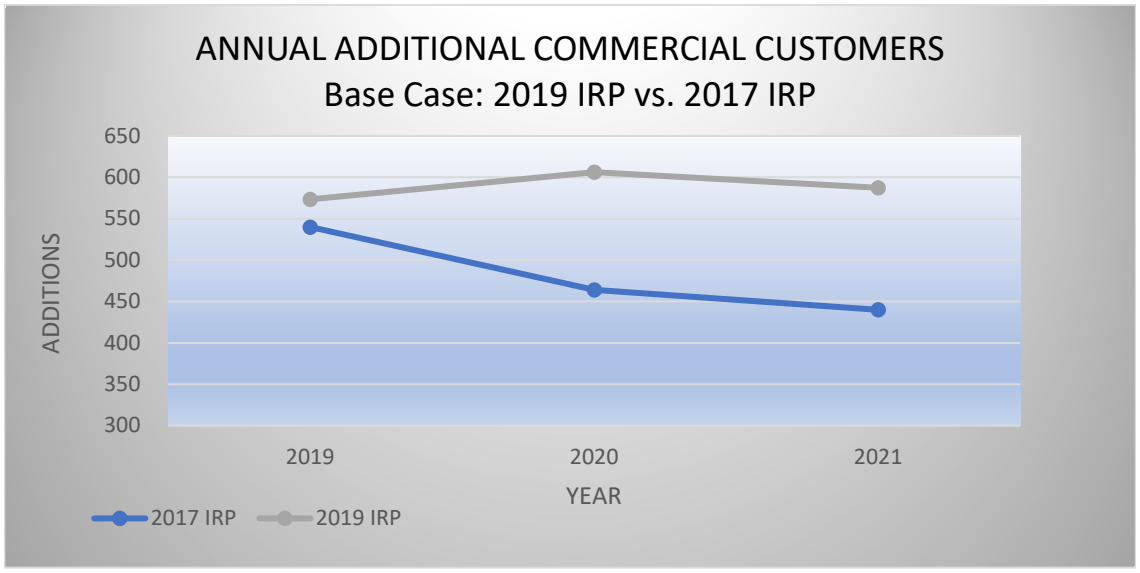


Figure 14: Annual Additional Commercial Customers – Base Case: 2019 IRP vs. 2017 IRP

Heating Degree Days & Design Weather

Intermountain's demand forecast captures the influence weather has on system loads by using Heating Degree Days (HDDs) as an input. HDDs are a measure of the coldness of the weather based on the extent to which the daily mean temperature falls below a reference temperature base. HDD values are inversely related to temperature which means that as temperatures decline, HDDs increase. The standard HDD base, and the one Intermountain utilizes in its IRP, is 65°F (also called HDD65). As an example, if one assumes a day where the mean outdoor temperature is 30°F, the resulting HDD65 would be 35 (i.e. 65°F base minus the 30°F mean temperature = 35 Heating Degree Days). Two distinct groups of heating degree days are used in the development of the IRP: Normal Degree Days and Design Degree Days.

Since Intermountain's service territory is composed of a diverse geographic area with differing weather patterns and elevations, Intermountain uses weather data from seven NOAA weather stations located throughout the communities it serves. This weather data is weighted by the customers in each of the geographic weather districts to arrive at weighted weather for the entire company. Several AOIs are also addressed specifically by this IRP. Those segments are assigned unique degree days as discussed in further detail below.

Normal Degree Days

A Normal Degree Day is calculated based on historical data, and represents the weather that could reasonably be expected to occur on a given day. The Normal Degree Day that Intermountain utilizes in the IRP is computed based on weather data for the 30 years ended December 2018. The HDD65 for January 1st for each year of the 30-year period is averaged to come up with the average HDD65 for the thirty year period for January 1st. This method is used for each day of the year to arrive at a year's worth of Normal Degree Days.

Design Degree Days

Design Degree Days are an estimation of the coldest temperatures that can be expected to occur for a given day. Design Degree Days are useful in estimating the highest level of customer demand that may occur, particularly during extreme cold or "peak" weather events. For IRP load forecasting purposes, Intermountain makes use of design weather assumptions.

Intermountain's design year is based on the premise that the coldest weather experienced for any month, season or year could occur again. The basis of a design year was determined by evaluating the weather extremes over the period of record from NOAA. That review revealed Intermountain's coldest 12 consecutive months to be the 1984/1985 heating season (October 1984 through September 1985). That year, with certain modifications discussed below, represents the base year for design weather. These degree days reflect a set of temperature extremes that have actually occurred in Intermountain's service area. These extreme

temperatures would result in a maximum customer usage response due to the high correlation between weather and customer usage.

Peak Heating Degree Day Calculation

Intermountain also engaged the services of Dr. Russell Qualls, Idaho State Climatologist, to perform a review of the methodology used to calculate design weather, and to provide suggestions to enhance the design weather planning. One crucial area that Dr. Qualls was able to assist Intermountain in was developing a method to calculate a peak day, as well as in designing the days surrounding the peak day.

To develop the peak heating degree day, or coldest day of the design year, Dr. Qualls fitted probability distributions to as much of the entire period of record from seven weather station locations (Caldwell, Boise, Hailey, Twin Falls, Pocatello, Idaho Falls and Rexburg) as was deemed reliable. From these distributions he calculated monthly and annual minimum daily average temperatures for each weather location, corresponding to different values of exceedance probability. Two probability distributions were fitted, a Normal Distribution, and a Pearson Type III (P3) distribution. Dr. Qualls suggested it is more appropriate for Intermountain to use the P3 distribution as it is more conservative from a risk reduction standpoint.

According to Dr. Qualls, "selecting design temperatures from the values generated by these probability distributions is preferable over using the coldest observed daily average temperature, because exceedance probabilities corresponding to values obtained from the probability distributions are known. This enables IGC to choose a design temperature, from among a range of values, which corresponds to an exceedance probability that IGC considers appropriate for the intended use".

Intermountain used Dr. Qualls' exceedance probability data to review the data associated with both the 50 and 100 year probability events. After careful consideration of the data, Intermountain determined that the company-wide 50 year probability event, which was a 79 degree day, would be appropriate to use for our design weather model. For modeling purposes, this 79 degree day was assumed to occur on January 15th.

Base Year Design Weather

To create a design weather year from the base year, a few adjustments were made to the base design year. First, since the coldest month of the last 30 years was December 1985, the weather profile for December 1985 replaced the January 1985 data in the base design year. For planning purposes, the aforementioned peak day event was placed on January 15th.

To model the days surrounding the peak event, Dr. Qualls suggested calculating a five-day moving average of the temperatures for the past 30-year period to select the five coldest consecutive days from the period. December 1990 contained this cold data. The coldest day of the peak

month (December 1985) was replaced with the 79 degree day peak day. Then, the day prior and three days following the peak day, were replaced with the four cold days surrounding the December 1990 peak day.

While taking a closer look at the heating degree days used for the LDCs, the Company noticed that the design weather HDDs in some months were lower than the normal weather HDDs. This occurred generally in the non-winter months, April through July. However, the Total Company and Idaho Falls Lateral design HDDs had this same occurrence in November, although the differences were minimal (1 to 3%). This occurred because, while the 1985 heating year was the coldest on record and therefore used as the base year for the design weather, the shoulder months were, in some cases, warmer than normal. Manipulating the shoulder and summer month design weather to make it colder would add degree days to the already coldest year on record, creating an unnecessary layer of added degree days. Intermountain decided not to adjust the summer and shoulder months of the design year.

After design modifications were completed, the total design HDD curve assumed a bell-shaped curve with a peak at mid-January (see Figure 15). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.

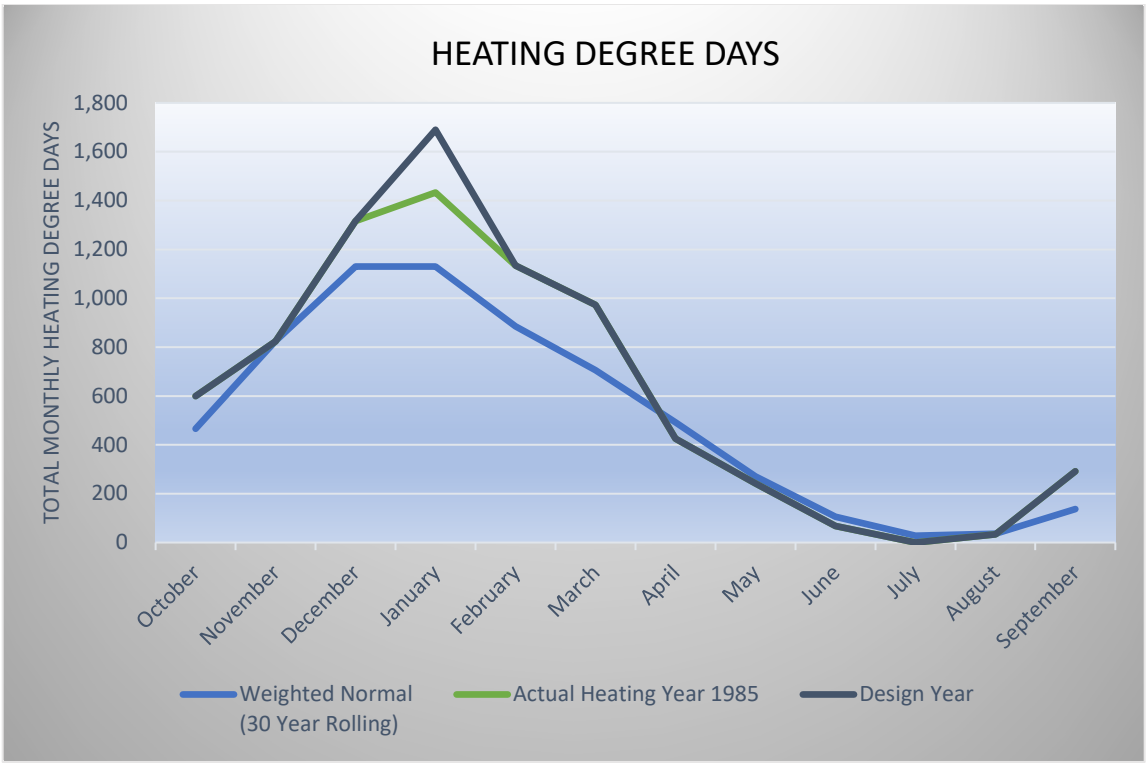


Figure 15: Heating Degree Days Graph

The resulting Normal, Base Year, and Design Year degree days by month are outlined in Table 6 displayed below:

Table 6: Heating Degree Days by Month

Monthly Heating Degree Days			
	Weighted Normal (30 Year Rolling)	Actual Heating Year 1985	Design Year
October	466	599	599
November	825	823	823
December	1,130	1,316	1,316
January	1,130	1,433	1,690
February	885	1,134	1,134
March	706	973	973
April	492	425	425
May	271	242	242
June	105	68	68
July	28	0	0
August	36	34	34
September	137	292	292
Total	6,211	7,339	7,596

Area Specific Degree Days

As noted earlier in this IRP, Intermountain has identified certain AOIs. These are areas Intermountain carefully manages to ensure adequate delivery capabilities either due to a unique geographic location, customer growth, or both.

The temperatures in these areas can be quite different from each other and from the Total Company. For example, the temperatures experienced in Idaho Falls or Sun Valley can be significantly different from those experienced in Boise or Pocatello. Intermountain continues to work on improving its capability to uniquely forecast loads for these distinct areas. A key driver to these area specific load forecasts is area specific heating degree days.

Intermountain has developed Normal and Design Degree Days for each of the areas of interest. The methods employed to calculate the Normal and Design Degree Days for each AOI mirrors the methods used to calculate Total Company Normal and Design Degree Days.

Usage Per Customer

The IRP planning process utilizes customer usage as an essential calculation to translate current and future customer counts into estimated demands on the distribution system and total demand for gas supply and interstate transportation planning. The calculated usage per customer is dependent upon weather and geographic location.

Methodology

Intermountain Gas utilizes a Customer Management Module (CMM) software product, provided by DNV GL as part of their Synergi Gas product line, to analyze natural gas usage data and to predict usage patterns on the individual customer level. DNV GL operates in over 100 countries and specializes in the maritime, oil, gas and energy industries. Its array of pipeline software has been a powerful engineering tool within the United States for decades, used by natural gas companies such as Avista, Pacific Gas and Electric, Dominion, Northwest Natural and Williams. The CMM product branch is used in correlation with Synergi Gas, a hydraulic modeling software program discussed in the Distribution System Modeling Section beginning on page 86 of this IRP.

The first step in operating the CMM is extensive data gathering from the Company's Customer Information System (CIS). The CIS houses historical monthly meter read data for each of Intermountain's customers, along with daily historical weather and the physical location of each customer. The weather data is associated with each customer based on location, and then related to each customer's monthly meter read according to the date range of usage.

After the correct weather information has been correlated to each meter read, a base load and weather dependent load are calculated for each customer through regression analysis over the historical usage period. DNV GL states that it uses a "standard least-squares-fit on ordered pairs of usage and degree day" regression. The result is a customer specific base load that is weather independent, and a heat load that is multiplied by a weather variable, to create a custom regression equation for each customer.

Should insufficient data exist to adequately predict a customer's usage factors, then CMM will perform factor substitution. Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute load factor data for a customer which lacks sufficient information for independent analysis.

The first step prior to analyzing data through the CMM was to determine the appropriate time period to include in the study. A study by the American Gas Association found that average natural gas usage per customer is on the decline. The average U.S. home using natural gas uses 40% less today than it did four decades ago. Following the national efficiency trend, Intermountain has also noticed a decline in usage per customer in its service territory. Some possible reasons for the decline in usage per customer include the Idaho Residential Energy Code which is a code adopted in Idaho, and many other areas, beginning in 1991. This building standard was designed to improve the energy efficiency of new homes and commercial buildings. Around the same time, efficiency standards for furnaces and water heaters improved.

Additionally, programmable thermostats are now routinely installed in new construction, and many are installed in older homes as a way to reduce energy expense.

All of these conservation influences began impacting usage per customer in the 1990's. Because approximately 69% of Intermountain's customers are new since 1990, the efficiency factors and building codes have had a tremendous influence on our customer base. Additionally, rising energy prices in the early 2000's provided customers an economic incentive to improve the energy efficiency of their homes. Finally, as the Company's new Energy Efficiency Program continues to grow, there will be greater downward pressure on Intermountain's actual usage per customer. All of these are contributing factors to the structural changes shown in the data.

With all the structural shifts in historical data, and the significantly increased quantity of data utilized for regression, Intermountain has selected a four-year time series ending in May of 2018 to develop the usage per customer equations within this IRP. The selected time series is aligned with the recommended time study from DNV GL and contains homogenous data from a single CIS system.

Usage per Customer by Geographic Area

The Company recognizes that there could be significant differences in the way its customers use natural gas throughout its geographically and economically diverse service territory. Being sensitive to areas that may require capital improvements to keep pace with demand growth, Intermountain separated customers into distinct AOIs, and then determined specific usages per customer for each. The AOIs that Intermountain studied for possible usage per customer refinements included: Canyon County, Central Ada County, State Street Lateral, Sun Valley Lateral, and Idaho Falls Lateral.

In order to refine usage per customer to an AOI, customer addresses were used to create groups by town, and towns were combined with their related AOI. Central Ada and State Street AOI's share towns in their respective territories, so a combined geographic area was created to calculate their shared usage per customer. Towns on the Sun Valley Lateral were combined to calculate a single usage per customer, but for flow analysis purposes it was found that more granular customer breakdowns are required, and the usage per customer was represented separately for each town due to the range of usages and geographic sensitivity along the lateral. The same Sun Valley Lateral methodology was applied to the Idaho Falls Lateral.

Conclusion

The process described above is an effective methodology for calculating usage per customer. As discussed elsewhere in this IRP, the Company is in the process of implementing a fixed-network metering system. As the fixed-network system becomes fully deployed, the Company will be able to utilize the gathered data to further refine its usage per customer calculation.

As discussed in the Load Demand Curves Section of this IRP, the usage per customer data produced from the process described above is a critical component in the development of the

Company's load demand curves. The usage per customer data is applied to the customer forecast and design weather to create daily core market load projections for the IRP period.

Large Volume Customer Forecast

Introduction

The Large Volume (LV) customer group is comprised of approximately 125 of the largest customers on Intermountain's system from both an annual therm use and a peak day basis. Only customers that use at least 200,000 therms per year are eligible for Intermountain's LV tariffs. The LV tariffs provide two firm delivery services: a bundled sales tariff (LV-1) and a distribution system only transport tariff (T-4). The Company also offers an interruptible distribution system only transportation tariff (T-3).

The LV customers are made up of a mix of industrial and commercial loads and, on average, they account for over 50% of Intermountain's annual throughput and 24% of the projected 2020 design base case peak day. Nearly 98% of 2020 LV throughput reflects distribution system only transportation tariffs where customer-owned natural gas supplies are delivered to Intermountain's various citygate stations for ultimate redelivery via the company's distribution system to the customers' facilities.

Because the LV customers' volumes account for such a large portion of Intermountain's overall throughput, the method of forecasting these customers' overall usage is an important part of the IRP. These customers' growth and usage patterns differ significantly from the residential and commercial customer groups in two ways: first, the LV customers' gas usage pattern as a whole is not as weather sensitive as the core market customers which means that forecasting LV volumes using standard regression techniques based on projected weather does not provide statistically significant results. Secondly, the total LV customer count is so few that it falls below the number required to provide an adequate sample size.

Therefore, Intermountain has developed and utilizes an alternate, and very accurate method of forecasting based on historical usage, economic trends and direct input from LV customers. The graph on the next page compares the total Large Volume sales forecast from the 2017 IRP against actual therm sales for the years 2017 – 2019.

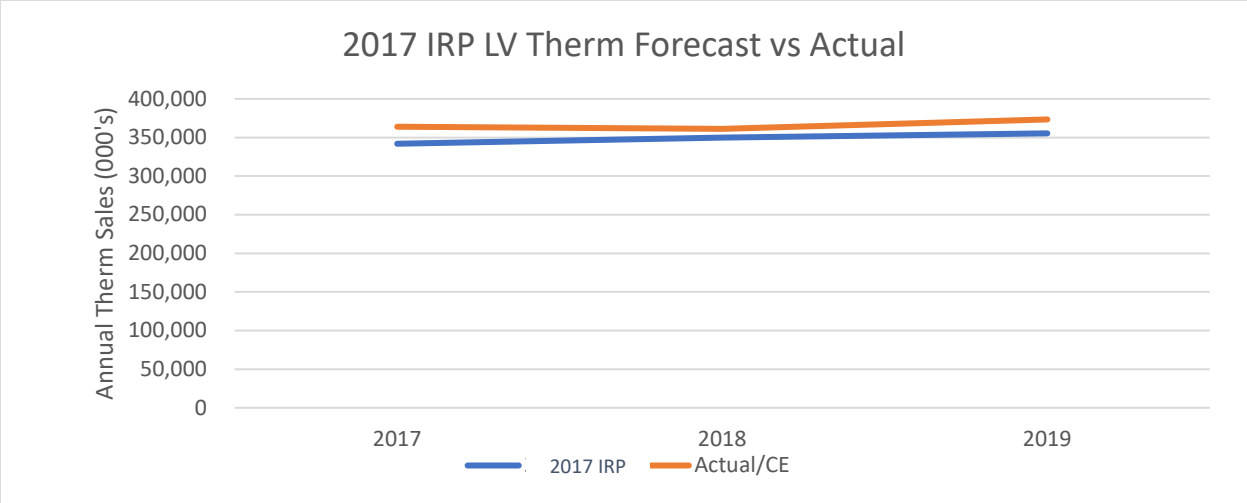


Figure 16: 2017 IRP Large Volume Therm Forecast vs Actual

Method of Forecasting

Intermountain maintains a historical therm usage database containing about 30 years of monthly therm usage data. The LV forecasting methodology begins by assessing each LV customer's monthly usage for the most recent three years. Then a representative 12-month period is selected as the base year. Typically, more weight is applied to the most recent 12-month period available unless known material variations would suggest a different base year.

An important source of forecasting information comes from the customers themselves. Prior to each IRP cycle, Intermountain sends out a survey to each customer requesting information relating to changes in usage patterns. Such a survey was sent out in July 2018. The survey form included a cover letter explaining the need for and the use of the requested information with the assurance that all responses would remain confidential (see Figure 17). The surveys provided each customer's historical peak day and monthly usage for the two years ending June 2018 (see Figure 18).

The historical information was provided to help the LV customer's management, engineers, and/or operations personnel identify how much and when recent natural gas usage patterns were likely to change going forward. Specifically, the survey requested projections of changes in natural gas consumption related to plant expansion, equipment modification or replacement and anticipated changes in product demand and production cycles through 2023.

Additionally, each customer was provided an opportunity to give recommendations for additional service options or other feedback. Nearly 40% of customers returned completed surveys and analysis of the returned surveys was completed by early September 2018. Where customers predicted material changes in future therm usage, the Company adjusted the annual 2019-23 base year data.

Forecast Scenarios

For the IRP, Intermountain prepared three separate LV monthly gas consumption forecasts (base case, high growth and low growth). The base case forecast started with the adjusted base year data as described above. That data was then combined with assumptions based on the most-expected economic trend to develop the five-year base case forecast. Other available data, including inquiries from the economic forecast provided by John Church (see Exhibit 2, Section A), other economic development organizations and alternate economic forecasts/assumptions were utilized to develop the high growth and low growth scenarios. For ease of analysis, the 125 existing and up to 14 projected new LV customers (per the high growth scenario) were combined into six homogeneous market segments:

2019 Existing LV Customers by Market Segment:

1) 17 potato processors
2) 38 other food processors including sugar, milk, beef, and seed companies
3) 3 chemical and fertilizer companies
4) 25 light manufacturing companies including electronics, paper, and asphalt companies
5) 34 schools, hospitals and other weather sensitive customers
6) 8 “other” companies including transportation-related businesses

Contract Demand

Every LV customer is required to sign a contract to receive service under any of the LV tariffs. An important element of the firm LV-1 sales and T-4 transportation contracts is the contract, or maximum daily firm quantity (MDFQ) which reflects the agreed upon maximum amount of daily gas and/or capacity the Company must be prepared to provide that firm LV customer on any given day including the projected system peak day that would occur during design weather.

T-3 customer contracts include a maximum daily quantity (MDQ) which represents the maximum amount of gas the Company’s service line and meter can flow. Because T-3 service is interruptible, Intermountain makes no assurances as to the amount of distribution capacity that will be available on any given day. For peak event modeling purposes, the IRP assumes T-3 customers are reduced to emergency plant-heat only. The IRP will use the term contract demand (CD) when referencing both MDFQ and MDQ. For this IRP, Intermountain utilized LV customer CD’s as they existed at June 1, 2018 for the beginning point of the base case.

While many LV customers predict that their annual usage requirements will likely grow through 2023, their peak day requirements are not projected to grow by a similar rate of increase. This is for two reasons: first, the increased annual usage is the result of adding additional daily shifts or adding production in weeks or months not previously utilized at 100% load factor (i.e. seasonal increases), and second, LV customers often take time to “grow” past an existing CD. Therefore, a certain pattern of therm usage will not necessarily equate with a commensurate level of growth in CD.

Load Profile vs MDFQ

Even though a monthly therm usage projection (i.e. load profile) is available for each customer, the IRP optimization model does not use the load profile for modeling purposes. The model instead uses the LV CD's because, as explained above, the LV customer group is not significantly weather sensitive so attempting to estimate daily usage using degree days, as is done for the core market, does not provide acceptable results. And without weather as the driver, it is difficult to estimate daily usage patterns. For these reasons it makes sense to use the customer CD as the daily requirement, as it reflects the known peak day obligation for every individual and each AOI. Most importantly, since Intermountain does not provide gas supply or interstate pipeline capacity for any of the transportation customers, the model does not need to project gas supply requirements for these customers but only the maximum amount of distribution capacity they will need on any given day.

Once the CD's are final, they are loaded directly into the optimization model by AOI and period. The optimization model also assumes that transport customers deliver an amount of zero cost gas supply equal to their aggregated CD for each transport rate class by AOI and period. That assumption allows the model to recognize that gas supply and/or interstate capacity requirements for the transport customers need to be delivered each day, but because it is not provided by Intermountain, there is no need to attempt to calculate an unknown cost that is meaningless to Intermountain.

System Reliability

It is important to note that before adding new firm load, engineering tests the system via its modeling system to determine whether or not the company could serve that load under design weather peak day loads before proceeding. That analysis is always completed prior to executing any firm contract for any new customer or an existing customer's expansion. Since the company knows the various parts of the system that may be at or nearing capacity constraints, those AOI's are given particular attention under load growth scenarios. This procedure assures current firm customers that new customers are not negatively affecting peak day deliverability.

General Assumptions

All current customers were assumed to remain on their current tariff and all forecast scenarios used the 2019 operating budget as a starting point. The IRP also calculated LV therm usage and MDFQ by AOI so that each geographic area of concern can be accurately modeled.

Base Case Scenario Summary

For the base case scenario, Intermountain assumed that the supply of natural gas remains plentiful and the price of natural gas stays competitive with other energy sources. The base case was compiled using historical usage and surveys with adjustments made to reflect known or probable changes of existing customers. The projected annual usage in the base case scenario increased by 6.6 million therms (0.5%) over the five-year period as seen in the table on the next page. The rate of projected annualized growth has slowed significantly from the last IRP largely

due to slowing or negative growth in the potato processors and other food processors market segments.

Table 7: Large Volume Base Case Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	112,620	108,620	108,770	108,870	-0.6%
Other Food, Dairy and Ag (B.)	155,304	156,860	157,541	159,922	159,988	0.7%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	29,805	0.1%
Manufacturing (D.)	22,463	23,174	23,812	24,490	24,928	2.6%
Institutional (E.)	24,789	25,327	25,471	25,615	25,820	1.0%
Other (F.)	18,173	18,381	18,881	19,081	19,261	1.5%
Total Base Case	362,046	366,167	364,130	367,683	368,672	0.5%

A. The potato processors group is forecast to be relatively flat over the five-year period. Demand for potato products remains flat but supplies remain plentiful. Some market participants claim that some former potato acreage is being replaced with hops. No new plants are assumed in the forecast and most of the plants in this group are looking for ways to lower the overall cost of production, conserve resources and maximize efficiencies leading to a slight decline in projected usage. The decrease in usage is due to the projected closure of one facility in 2021.

B. The other food processing group is projected to see slight growth over the five-year period. While the huge increase in the sugar and other food processing segment over the past decade is projected to flatten, Intermountain still forecasts growth for dairy producers. The base case assumes one new dairy customer.

C. The three plants in the chemicals/fertilizers group will continue at current levels with nearly no projected growth in the forecast. The base case assumes no new customers.

D. The manufacturing group is expected to see strong growth. The growth is largely due to increases in electronics manufacturing companies and the addition of two new companies.

E. The institutional group is projected to grow at 1.0% a year, due mainly to new hospitals that have recently been built or will be built in the coming years.

F. The usage in the other group is projected to see some reasonably strong growth largely due to growth in customers using natural gas as a transportation fuel.

High Growth Scenario Summary

The high growth scenario figures incorporate usage data from the base case with adjustments for additional growth that are assumed to occur if the economy continues to expand at its recent pace. The LV volume in the high growth scenario is approximately 7% above the 2023 base case. The 32 million therm increase over the 2019 estimate of 362 million therms (2.1%) results from growth in every market segment. The following table summarizes the changes over this period:

Table 8: Large Volume High Growth Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	114,420	114,920	116,070	116,170	1.0%
Other Food, Dairy and Ag (B.)	155,304	166,695	169,696	171,147	171,363	2.5%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	32,305	2.2%
Manufacturing (D.)	22,463	23,174	23,812	24,490	24,928	2.6%
Institutional (E.)	24,789	28,080	28,403	28,397	28,872	3.9%
Other (F.)	18,173	19,032	19,565	19,774	19,967	2.4%
Total High Growth	362,046	381,206	386,201	389,683	393,605	2.1%

A. Potato production is up from the 2017 IRP projections, and the future shows steady growth for the potato industry. This scenario shows steady growth largely due to significant expansions at three existing facilities. Strong potato production assumes increasing demand, good quality and yield and higher prices. Very competitive natural gas prices keep these plants on gas rather than oil or alternative fuels. However, no new customers are assumed.

B. The other food processors are projected to show strong growth across the reporting periods. The assumptions include strong growth in the sugar industry, and strong growth and several plant expansions in the dairy industry. The meat and ag/feed industries remain relatively flat. Overall this segment assumes four new customers.

C. The chemical/fertilizer group is projected to increase due to the assumption of one new plant by 2023. The three existing plants show little growth over the IRP.

D. The manufacturing group is projected to have a strong increase over the period due to increases in high-tech manufacturing, plus the addition of one new plant.

E. The institutional group, which is made up of schools, hospital and tourism-based facilities is also projected to experience strong growth. This assumption is driven by the expectation of continuing cooler than normal weather, which affects this weather-sensitive group, and the addition of two new customers.

F. The other group is projected to grow slightly, with some increased usage at a greenhouse, and the addition of a new user. Usage will be relatively flat across the reporting period in the high growth scenario.

Low Growth Scenario Summary

The projected usage for the low growth scenario is based upon the assumption that the agricultural economy will be flat-to-declining with very little growth in sales and production. It is also assumed that natural gas prices will be relatively flat and see significant competition from renewables and other energy sources. With those assumptions, a downturn is projected beginning in 2020 that continues through 2023. The low growth scenario projections start 2% below 2019 with overall usage decreasing a projected 1.5% by 2023.

Table 9: Large Volume Low Growth Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	109,720	107,670	107,070	106,170	-1.3%
Other Food, Dairy and Ag (B.)	155,304	150,695	140,695	140,695	140,695	-2.4%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	29,805	0.1%
Manufacturing (D.)	22,463	23,094	22,694	22,494	22,494	0.0%
Institutional (E.)	24,789	23,019	22,949	22,944	22,939	-1.9%
Other (F.)	18,173	18,079	18,444	18,444	18,444	0.4%
Total Low Growth	362,046	354,412	342,257	341,452	340,547	-1.5%

A. The price of natural gas was assumed to be less competitive against the delivered price of alternative sources and global potato consumption is assumed to soften significantly. This segment, as a whole, generally looks at any way possible to conserve energy and make its plants more efficient. This scenario assumes the loss of one existing plant, softening at several other plants and no new customers.

B. The other food processing group is expected to soften significantly with large decreases in sugar processing, flat usage among the dairy customers and no new customers.

C. The projection for the chemical/fertilizer group remains flat with no new customers.

D. The manufacturing group is also projected to remain flat with some growth in high-tech companies that is offset by the loss of several of the smaller customers. Additionally, the low growth scenario assumes the loss of a few state or federal highway projects which leads to a contraction in usage among asphalt customers. However, this segment is still projected to add two smaller customers by 2023.

E. The projection of a decline for the institutional group is attributed to forecasted warmer than normal weather affecting universities, schools, and hospitals, as well as little growth in the tourism industry and the addition of only one small customer.

F. The other group's usage of natural gas is projected to remain mostly flat as the forecast assumes no growth in the transportation related customers as well as the loss of one smaller customer. Most of the loss is offset by the addition of a new customer in 2020.

LARGE VOLUME CUSTOMER SURVEY – COVER LETTER

July 16, 2018

Dear Intermountain Gas Customer

Intermountain Gas values you as a customer and we are committed to meeting your expectations of receiving reliable energy services to your facility. We continue to see strong and steady growth in natural gas usage from all sectors of our business. That growth coupled with the potential for extremely frigid winter weather underscores the importance of our long-term planning efforts.
The Idaho Public Utilities Commission (IPUC) requires Intermountain to file a bi-annual, long-term Integrated Resource Plan (IRP) that gives both the Commission and our customers a close-up view of our planning efforts. The IRP provides an opportunity for you to participate in the process and to assess our forecast including its inputs, underlying methodologies and conclusions. The IRP we file with the IPUC documents the entire process and it provides assurance to our customers that we utilize detailed, transparent and industry accepted practices as we plan to meet your energy needs in a prudent manner.

We are now beginning to prepare the data inputs for the 2019–2023 IRP. Our demand or usage forecast is the basis for the entire IRP and therefore it is critical that it be as accurate as possible. To this end, I am writing to request your assistance by providing projections of your facility's natural gas requirements for the next several years.

I have enclosed a survey form that requests information relative to projected changes in your facility's annual and peak day natural gas requirements and alternate fuel plans. To provide context, I have included actual annual and peak day therm use (where available) for the two most recent 12-month periods ending June 2018 and June 2017. I recognize the time required to complete this survey but including your projections in our IRP will improve its accuracy and I assure you that we do use the data you provide.

Please return your completed survey, including any comments or questions you may have, by August 17, 2018. To show my appreciation for your participating in our IRP forecast, if you return the completely filled-out survey by the August 17th deadline, I will enter your name in a raffle for one of three gifts: an Intermountain Gas branded Polo shirt, a box of Titleist PRO V1 golf balls or an Intermountain Gas branded baseball-type hat. Note only one entry per company will be entered into the raffle.

As always, any information you provide will be strictly confidential, will not be shared with any other entity and will be aggregated with data from other similar situated customers in any public filing. Should you have any questions or if I can be of assistance to you, please call me at my office (208-377-6118), my cell phone (208-850-2139) or you can always email me at dave.swenson@intgas.com.

I thank you in advance for your willingness to help.

David Swenson
Manager, Industrial Services
Intermountain Gas Company

Enclosures

Figure 17: Large Volume Customer Survey Cover Letter Sample

Intermountain Gas Company – 2019-2024 Large Volume Customer Survey

Company Name: [redacted]
Account # [redacted]
Street Address: [redacted]
City/State/Zip: [redacted]

Rate Class: [redacted]
Contract Expiration Date: [redacted]
Contract Demand (or MDFQ): [redacted]

HISTORICAL INFORMATION

	Annual Therms	Winter Peak Day	Date of Peak Day
12 Months Ending June 2018	[redacted]	[redacted]	[redacted]
12 Months Ending June 2017	[redacted]	[redacted]	[redacted]

REQUESTED INFORMATION – PROJECTED THERMS

Description	2019	2020	2021	2022	2023	2024
Annual Therms						
Peak Day Therms						

What is the prime reason for the projected change in therm use? _____

Are the 2019-24 therm use projections above lower than they otherwise might have been due to the use of an alternative energy source? ☐ Yes ☐ No
If yes, how much of your 2018 natural gas usage did alternative energy offset? Annual Therms= _____ Peak Day Therms_____

What percent of your current peak day energy needs, served by natural gas, can be served by existing alternative fuel? _____

What is your existing alternative source of energy? ☐ None ☐ Coal ☐ Oil ☐ Other (specify) _____

If you are contemplating incorporating an alternative energy source, what is your preference? ☐ None ☐ Coal ☐ Oil ☐ Other (specify) _____

Do you plan to employ energy saving or other conservation measures that will reduce your Therms of natural gas? ☐ Yes ☐ No
If yes, please estimate the reduction natural gas therms (therms or percent): Annual Therms = _____ Peak Day Therms = _____

What is the combined total of the input ratings for all natural gas-fired equipment? (circle correct units) _____ **[btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]**

Do you plan to install additional natural gas fired equipment through 2019? ☐ Yes ☐ No
If yes, what year do you expect to install _____ and what is the input rating? (circle correct units) _____ **[btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]**

Are there any additional service options would you like Intermountain to consider or do you have any suggestions for Intermountain that could help enhance its service?

_____

_____

_____

ANY INFORMATION PROVIDED VIA THIS FORM WILL REMAIN CONFIDENTIAL WITH INTERMOUNTAIN GAS COMPANY
Please return via mail to 555 S Cole Road, Boise ID 83709 or email to Dave.Swenson@intgas.com by August 17, 2018

Figure 18: Large Volume Customer Survey Sample

Supply & Delivery Resources

Supply & Delivery Resources Overview

Once future load requirements have been forecasted, currently available supply and delivery resources are matched with demand to identify system deficits. Essential components considered when reviewing supply and delivery resources include identifying currently available supply resources, delivery capacity, and other resources that can offset demand such as energy efficiency programs or large volume customers with alternative fuel sources.

Supply and deliverability are considered by AOI to identify system constraints that result from forecasted demand. By comparing demand versus capacity for each AOI, the Company is better able to select capacity constraint solutions that consider cost effectiveness, operations and maintenance impacts, project viability, and future growth.

After analyzing resource requirements for each AOI, the data is aggregated to provide a total company perspective. Supply and delivery resources that are currently available are compared to the six total company demand scenarios that were established in the demand forecast. In the Load Demand Curves Section, beginning on page 90, demand and capacity are compared to clearly identify deficits. Alternative solutions for how the deliverability deficits will be resolved are considered in the Optimization and Planning Results sections of this Integrated Resource Plan.

Traditional Supply Resources

Overview

Natural gas is a fundamental fuel for Idaho's economic and environmental future: heating our homes, powering businesses, moving vehicles and serving as a key component in many of our most vital industrial processes. The natural gas marketplace continues to change but Intermountain's commitment to act with integrity to provide secure, reliable and price-competitive firm natural gas delivery to its customers has not. In today's energy environment, Intermountain bears the responsibility to structure and manage a gas supply and delivery portfolio that will effectively, efficiently, reliably and with best value meet its customers' year-round energy needs. Through its long-term planning, Intermountain continues to identify, evaluate and employ best-practice strategies as it builds a portfolio of resources that will provide the value of service that its customers expect.

The Traditional Supply Resources Section outlines the energy molecule and related infrastructure resources upstream of Intermountain's distribution system necessary to deliver natural gas to the Company's distribution system. Specifically included in this discussion is the natural gas commodity (or the gas molecule), various types of storage facilities and interstate gas transportation pipeline capacity. This section will identify and discuss the supply, storage and transportation capacity resources available to Intermountain and how they may be employed in the Company's portfolio approach to gas delivery management.

Background

The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Natural gas is a fossil fuel; a naturally occurring mixture of combustible gases, principally methane, found in porous geologic formations beneath the surface of the earth. It is produced or extracted by drilling into those underground formations or reservoirs and then moving the gas through gathering systems and pipelines to customers in often far away locations.

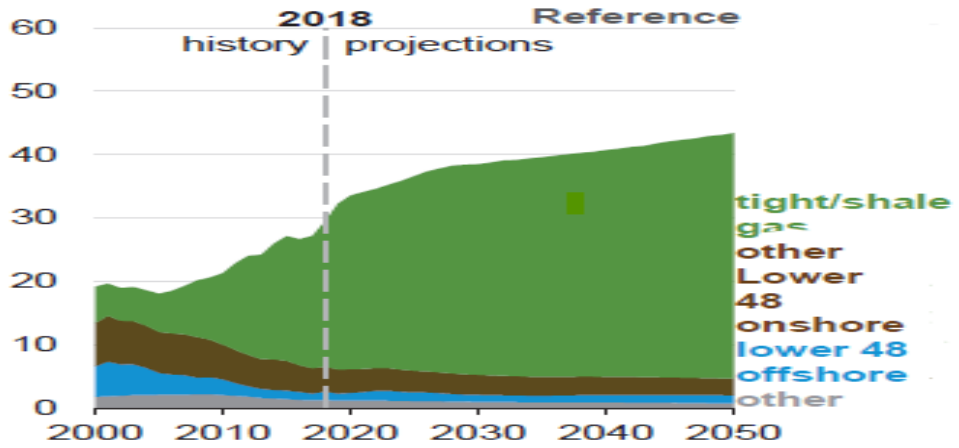
Intermountain is fortunate to be located between two prolific gas producing regions in North America. The first, the Western Canadian Sedimentary Basin (WCSB) in Alberta and British Columbia supplies approximately 79% of Intermountain's natural gas. The other region, known as the Rockies, includes many different producing basins in the states of Wyoming, Colorado and Utah where the remainder of the Company's supplies are sourced. The Company also utilizes storage facilities to store natural gas supply during the summer when prices are traditionally lower and save it for use during the winter to offset higher seasonal pricing.

Intermountain's access to the gas produced in these basins is wholly dependent upon the availability of pipeline transportation capacity to move gas from those supply basins to Intermountain's distribution system. The Company is fortunate, in that the interstate pipeline that runs through Intermountain's service territory is a bi-directional pipeline. This means it can

bring gas from the north or south. Having the bi-directional flow capability allows Intermountain's customers to benefit from the least cost gas pricing in most situations and ample capacity to transport natural gas to Intermountain's citygates. A basic discussion of gas supply, storage and interstate transportation capacity resources follows.

Gas Supply Resource Options

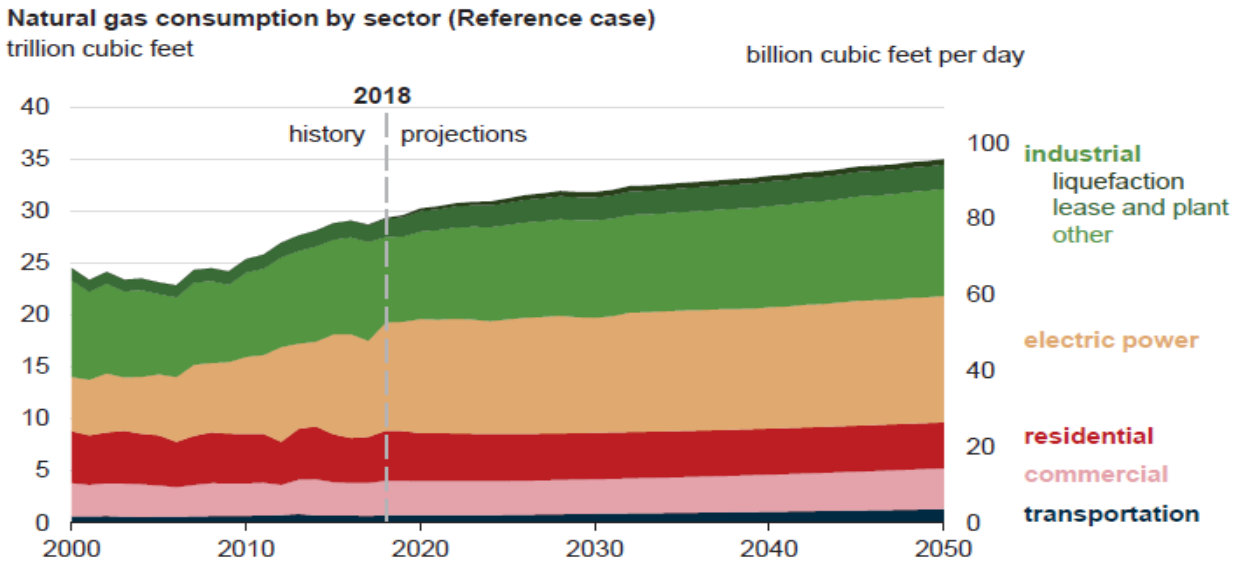
Over the past few years, advances in technology have allowed for the discovery and development of abundant supplies of natural gas within shale plays across the United States and Canada. This shale gas revolution has changed the energy landscape in the United States. Natural gas production levels continue to surpass expectations despite low gas prices and concerns about shale production techniques (See Figure 19 below).



Source: EIA AEO2019

Figure 19: Natural Gas Sources

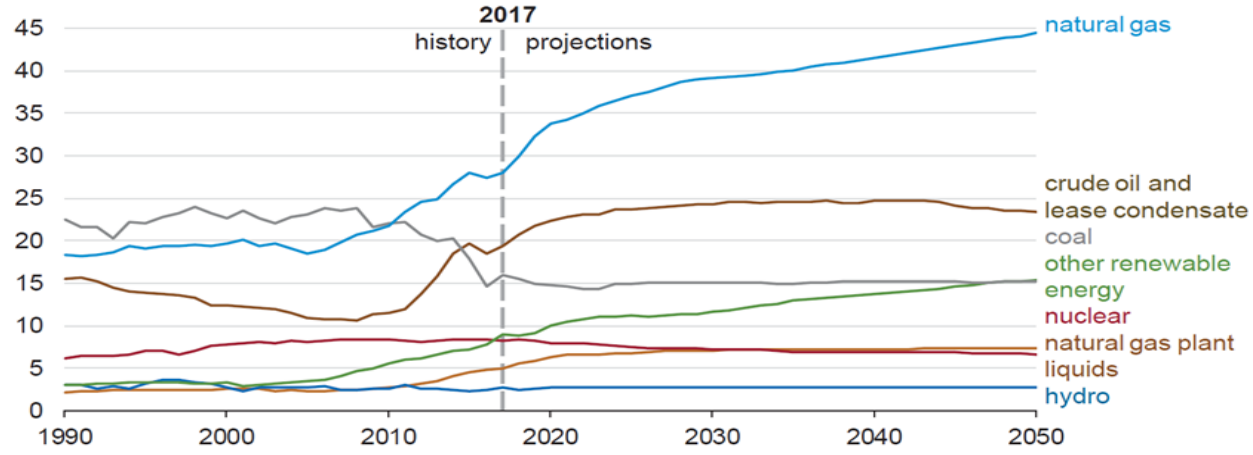
Projected low prices for natural gas have made it a very attractive fuel for natural gas fired electric generation as utilities are replacing coal-fired generation. Combine this with the industrial sector's post-recession recovery as they take advantage of low natural gas prices, and the result is a significant change in demand loads. See Figure 20 on the next page for consumption by sector, 2000-2050.



Source: EIA AEO2019

Figure 20: Natural Gas Consumption by Sector

Improved technologies for finding and producing nonconventional gas supplies have led to dramatic increases in gas supplies. Figure 21 below shows that shale gas production is not only replacing declines in other sources but is projected to increase total annual production levels through 2050.



Source: EIA AEO2018

Figure 21: Shale Gas Production Trend

While natural gas prices continue to exhibit volatility from both national, global and regional perspectives, the laws of supply and demand clearly govern the availability and pricing of natural gas. Recent history shows that periods of growing demand tends to drive prices up which in turn generally results in consumers seeking to lower consumption. At the same time, producers typically increase investment in activities that will further enhance production. Thus, falling

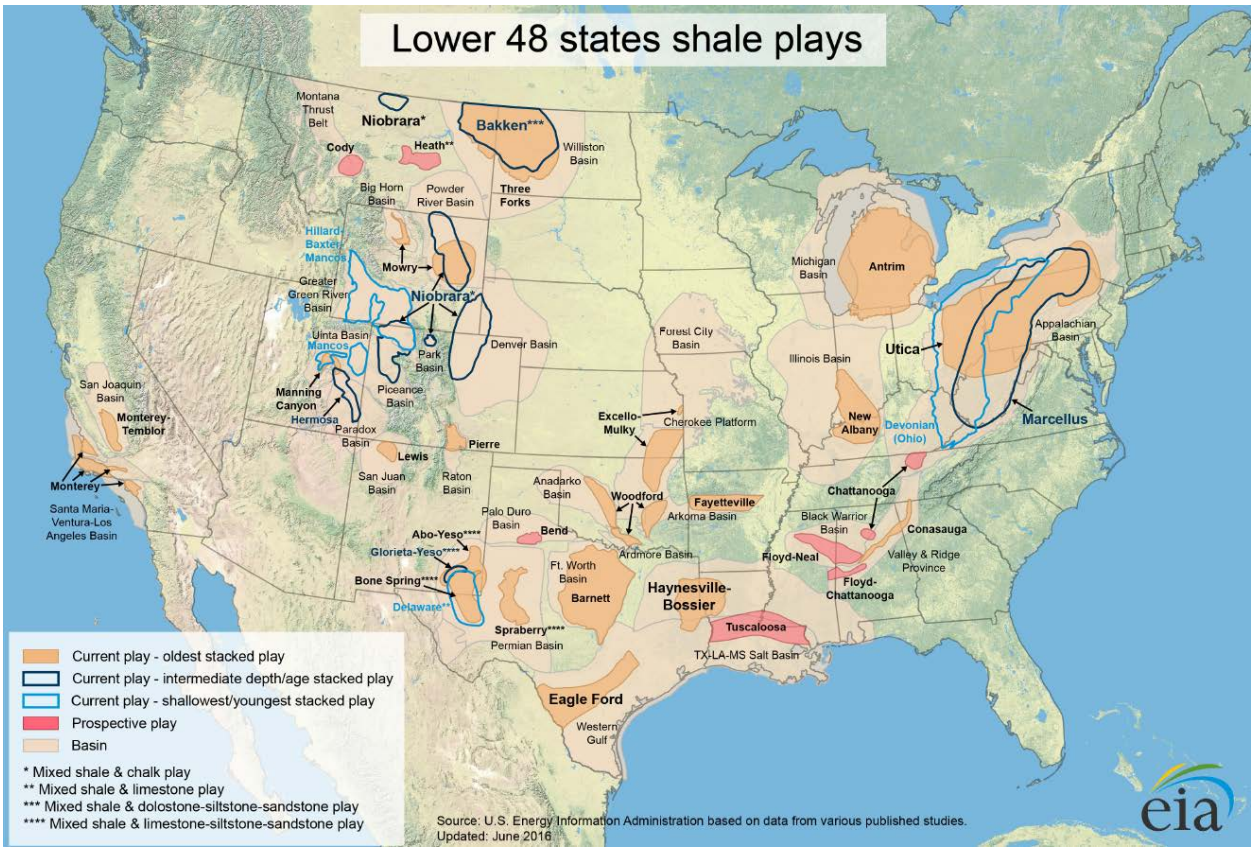
demand coupled with increasing supplies tends to swing prices lower. This in turn leads to falling supplies and increased demand which begins the cycle anew (see Figure 21 on the previous page for shifting demand). Finding equilibrium in the market has been challenging for all market participants but at the end of the day, the competitive market clearly works; the challenge is avoiding huge swings that result in either demand destruction or financial distress in the exploration and production business.

Driven by technological breakthroughs in unconventional gas production, major increases in North American natural gas reserves and production have led to supply growth significantly outgaining forecasts in recent years. Thus, natural gas producers have sought new and additional sources of demand for the newfound volumes. The abundant supply of natural gas discussed above has resulted in the United States becoming a net exporter of liquefied natural gas (LNG) versus the expectation of it being a net importer several years ago. The currently operational LNG export facilities in the United States together with additional new facilities on the drawing board will result in a significant new market for the incremental gas supplies being developed and produced.

Shale Gas

Shale gas has changed the face of U.S. energy. Today, reserve and production forecasts predict ample and growing gas supplies through 2050 because of shale gas. The fact that shale gas is being produced in the mid-section of the U.S has displaced production from more traditional supply basins in Canada and the Gulf Coast. There have been some perceived environmental issues relating to shale production, but most studies indicate that if done properly, shale gas can be produced safely. Customers now enjoy the lowest natural gas prices in years due to the increased production of shale gas.

Per the EIA, the portion of U.S. energy consumption supplied by domestic production has been increasing since 2005, when it was at its historical low point (69%). Since 2005, production of domestic resources, particularly natural gas and crude oil, have been increasing because of shale gas production. Figure 22 on the next page identifies the shale plays in the lower 48 states.



Source: Energy Information Administration based on data from various published studies.

Updated June 2016.

Figure 22: US Lower 48 States Shale Plays

Supply Regions

As previously stated, Intermountain's natural gas supplies are obtained primarily from the WCSB and the Rockies. Access to those abundant supplies is completely dependent upon the amount of firm transportation capacity held on the applicable pipelines for delivering such gas to Intermountain's service territory. Transportation capacity is so important that a discussion of the Company's purchases of natural gas cannot be fully explored without also addressing pipeline capacity. On average, Intermountain currently purchases approximately 79% of its gas supplies from the WCSB and the remainder from the Rockies. However, due to certain flexibility in Intermountain's firm transportation portfolio, it is afforded the opportunity to procure some portion of its annual needs from supply basins which may offer lower cost gas supplies in the future.

Alberta

Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Energy via Nova, and Foothills pipelines) and two U.S. pipelines (Gas Transmission Northwest (GTN), and Williams Northwest Pipeline, (NWP)) as seen below in Figure 23.

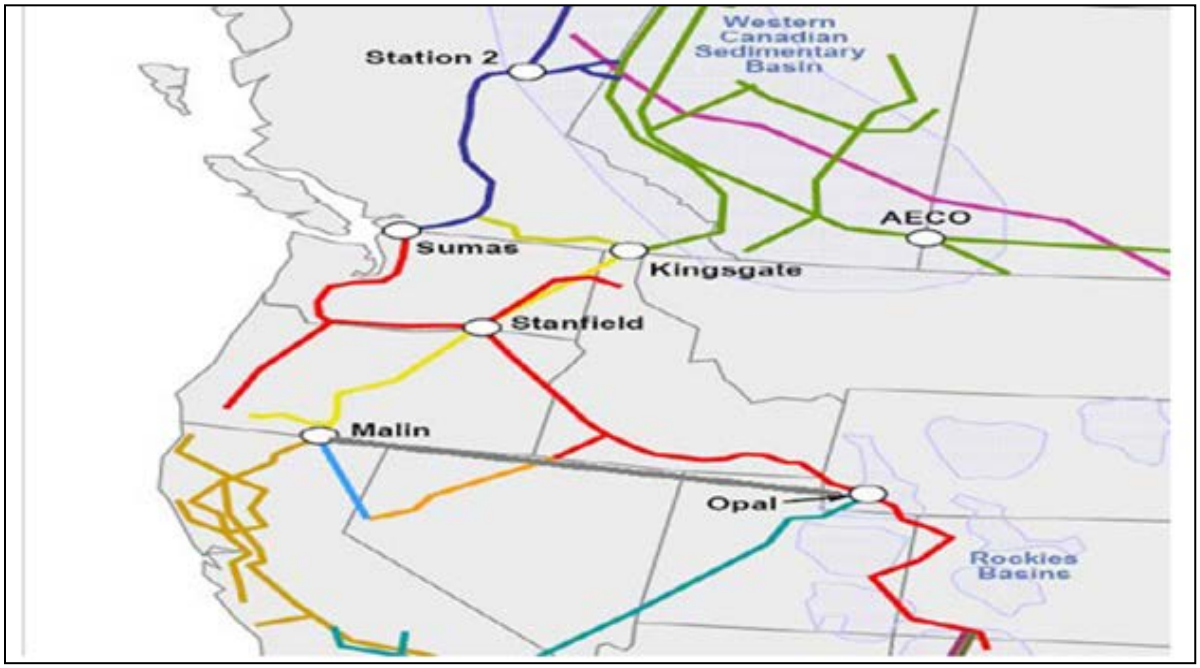


Figure 23: Supply Pipeline Map

Intermountain will continue to utilize a significant amount of Alberta supplies in its portfolio. The Stanfield interconnect between NWP and GTN offers operational reliability and flexibility over other receipts points both north and south. Where these supplies once amounted to a minor portion of the Company's portfolio, today's purchases amount to over 76% of the Company's annual purchases.

British Columbia

British Columbia has traditionally been a source of competitively priced and abundant gas supplies for the Pacific Northwest. Gas supplies produced in the province are transported by Spectra Energy to an interconnect with NWP near Sumas, WA. Historically, much of the provincial supply had been somewhat captive to the region due to the lack of alternative pipeline options into eastern Canada or the midwestern U.S. However, pipeline expansions into these regions have eliminated that bottleneck. Although these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to impede ultimate delivery to Intermountain's citygates. An exception to pipeline constraints occurred during the winter of 2018 when Enbridge had a major disruption from a pipeline rupture that occurred on October 9, 2018. The ensuing winter months saw a reduction in capacity for British Columbia gas supplies to be delivered at Sumas due to the incident and pipeline integrity testing required by the National Energy Board in Canada to ensure safe and

reliable pipeline conditions. Those interruptions along with a cold and long winter had a significant impact on pricing. However, due to the predominance of Intermountain's supplies coming from Alberta and delivered via GTN at Stanfield, coupled with Intermountain's ability to utilize its liquefied natural gas storage contracts on NWP's system, it was able mitigate the impact to its customers of the dramatic short-term price increases.

Rockies

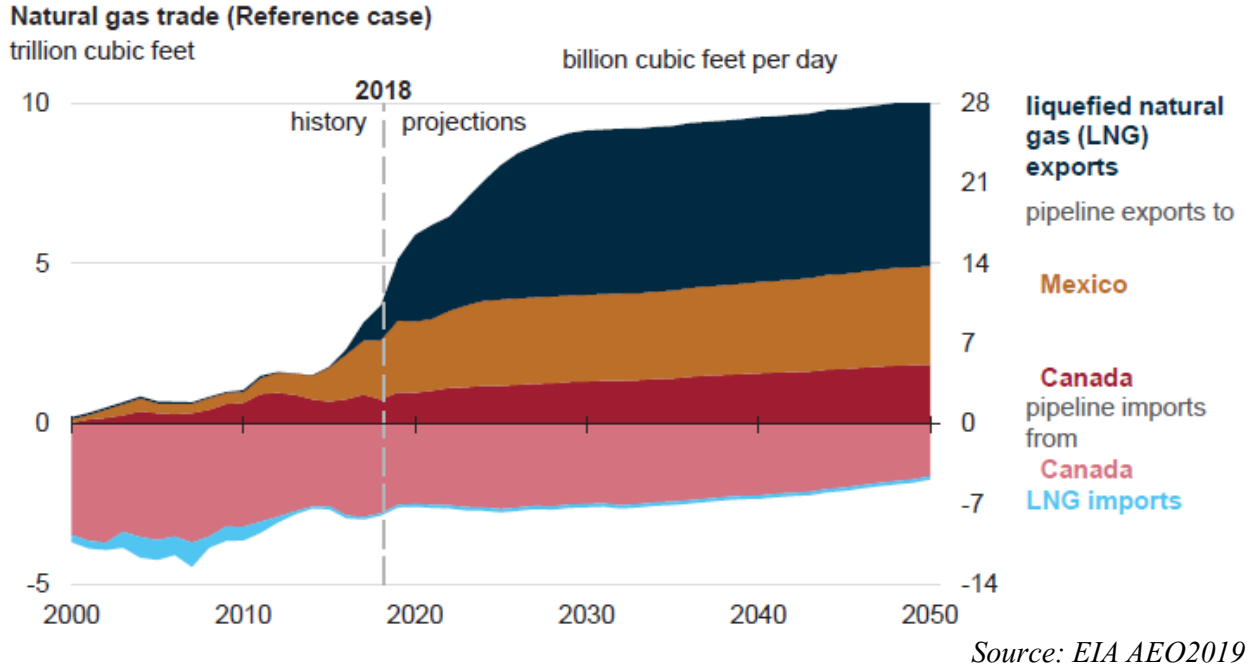
Rockies supply has been the second largest source of supply for Intermountain because of the ever-growing reserves and production from the region coupled with firm pipeline capacity available to Intermountain. Additionally, Rockies supplies have been readily available and highly reliable. Historically, pipeline capacity to move Rockies supplies out of the region has been limited, which has forced producers to compete to sell their supplies to markets with firm pipeline takeaway capacity. Several pipeline expansions out of the Rockies have greatly minimized or eliminated most of the capacity bottlenecks, so these supplies can now more easily move to higher priced markets found in the Midwest, East or in California. Consequently, even though growth in Rockies reserves and production continues at a rapid pace reflecting increased success in finding tight sand, coal seam and shale gas, the more efficient pipeline system has largely eliminated the price advantage that Pacific Northwest markets had enjoyed.

While Intermountain's firm transportation portfolio does provide for accessing Rockies gas supplies, and as discussed above, Intermountain has chosen today and for the foreseeable future to purchase the predominance of its annual supply needs out of Alberta due to the lower cost environment from that supply basin. However, due to its close proximity, Intermountain does purchase the lower cost Rockies gas supplies in the summer for injection into its Clay Basin storage accounts located in North Eastern Utah.

Export LNG

Growth in North American natural gas supplies (see Shale Gas above) has eliminated discussion about LNG import facilities. Because LNG is traded on the global market, where prices are typically tied to oil, U.S. produced LNG is very competitive. LNG exports now play a role in the overall supply portfolio of U.S. supply, with several new LNG export facilities proposed or in production. The U.S. is now a net exporter of natural gas in large part due to LNG.

Figure 24 below identifies LNG imports by year going back to 2000. A downward trend since 2007 is apparent. In 2015 LNG imports were at their lowest levels since 2000 and trending to net exports. The projection still shows a large growth in the LNG export market.



Source: EIA AEO2019

Figure 24: Natural Gas Trade

Types of Supply

There are essentially two main types of gas supply: firm and interruptible. Firm gas commits the seller to make the contracted amount of gas available each day during the term of the contract and commits the buyer to take that gas on each day. The only exception would be force majeure events where one or both parties cannot control external events that make delivery or receipt impossible. Interruptible or best efforts gas supply typically is bought and sold with the understanding that either party, for various reasons, does not have a firm or binding commitment to take or deliver the gas.

Intermountain builds its supply portfolio on a base of firm, long-term gas supply contracts but includes all the types of gas supplies as described below:

1. Long-term: gas that is contracted for a period of over one year.
2. Short-term: gas that is often contracted for one month at a time.
3. Spot: gas that is not under a long-term contract; it is generally purchased in the short-term on a day ahead basis for day gas and during bid week prior to the beginning of the month for monthly spot gas.

4. Winter Baseload: gas supply that is purchased for a multi-month period most often during winter or peak load months.

5. Citygate Delivery: natural gas supply that is bundled with interstate transportation capacity and delivered to the Intermountain citygate meaning that it does not use the Company's existing transportation capacity.

Pricing

The Company does not currently utilize NYMEX based products to hedge forward prices but buys a portion of its gas supply portfolio at fixed priced forward physicals. Purchasing fixed price physicals provides the same price protection without the credit issues that come with financial instruments. A certain level of fixed price contracts allows Intermountain to participate in the competitive market while avoiding upside pricing exposure. While the Company does not utilize a fully mechanistic approach, its Gas Supply Oversight Committee meets frequently to discuss all gas portfolio issues which helps to provide stable and competitive prices for its customers.

For IRP purposes, the Company develops a base, 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. Intermountain considers price forecasts from several sources, such as Wood Mackenzie, EIA, S&P Global, NYMEX Henry Hub, Northwest Power and Conservation Council, as well as Intermountain's own observations of the market to develop the low, base, and high price forecasts. For optimization purposes, Intermountain uses pricing forecasts from four sources for the AECO, Rockies and Sumas pricing points along with a proprietary model based upon those forecasts. The selected forecast includes a monthly base price projection for each of the three purchase points, as seen in Figure 25.

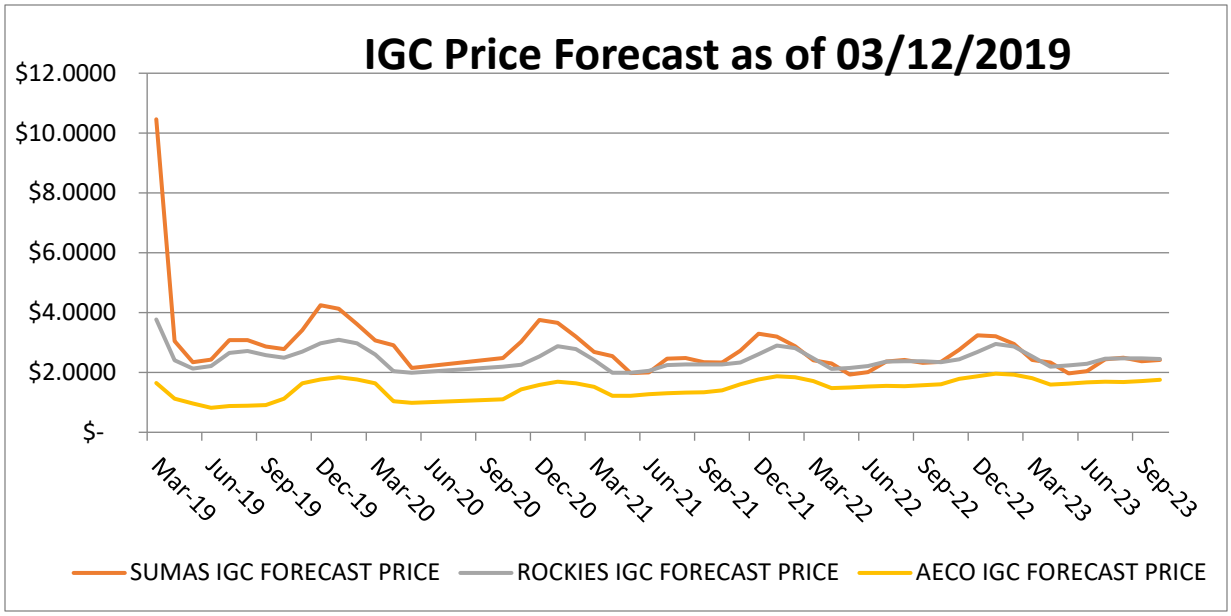


Figure 25: Intermountain Price Forecast as of 03/12/2019

Storage Resources

The production of natural gas and the amount of available pipeline capacity are very linear in nature; changes in temperatures or market demand does not materially affect how much of either is available daily. As the Resource Optimization Section discusses (see page 111), a peak day only occurs for, at most, a few days out of the year. The demand curve then drops rapidly back to more normal winter supply levels before dropping off drastically headed into the summer months. Attempting to serve the entire year at levels required to meet peak demand would be enormously expensive. So, the ability to store natural gas during periods of non-peak demand for use during peak periods is a cost-effective way to fill the gap between static levels of supply and capacity versus the non-linear demand curve.

Intermountain utilizes storage capacity in four different facilities from western Washington to northeastern Utah. Two are operated by NWP: one is an underground project located near Jackson Prairie, WA (JP) and the other is a liquefied gas (LS) facility located near Plymouth, WA (See map, Figure 26). Intermountain also leases capacity from Dominion Energy Pipeline's Clay Basin underground storage field and operates its own LNG facility located in Nampa, ID. Additionally, Intermountain owns a satellite LNG facility in Rexburg, ID. The Rexburg facility is supplied with LNG from the Nampa LNG facility.

All storage resources allow Intermountain to inject gas into storage during off-peak periods and then hold it for withdrawal whenever the need arises. The advantage is three-fold: 1) the Company can serve the extreme winter peak while minimizing year-round firm gas supplies; 2) storage allows the Company to minimize the amount of the year-round interstate capacity resources required and helps it to use existing capacity more efficiently; and 3) storage provides

a natural price hedge against the typically higher winter gas prices. Thus, storage allows the Company to meet its winter loads more efficiently and in a cost-effective manner.

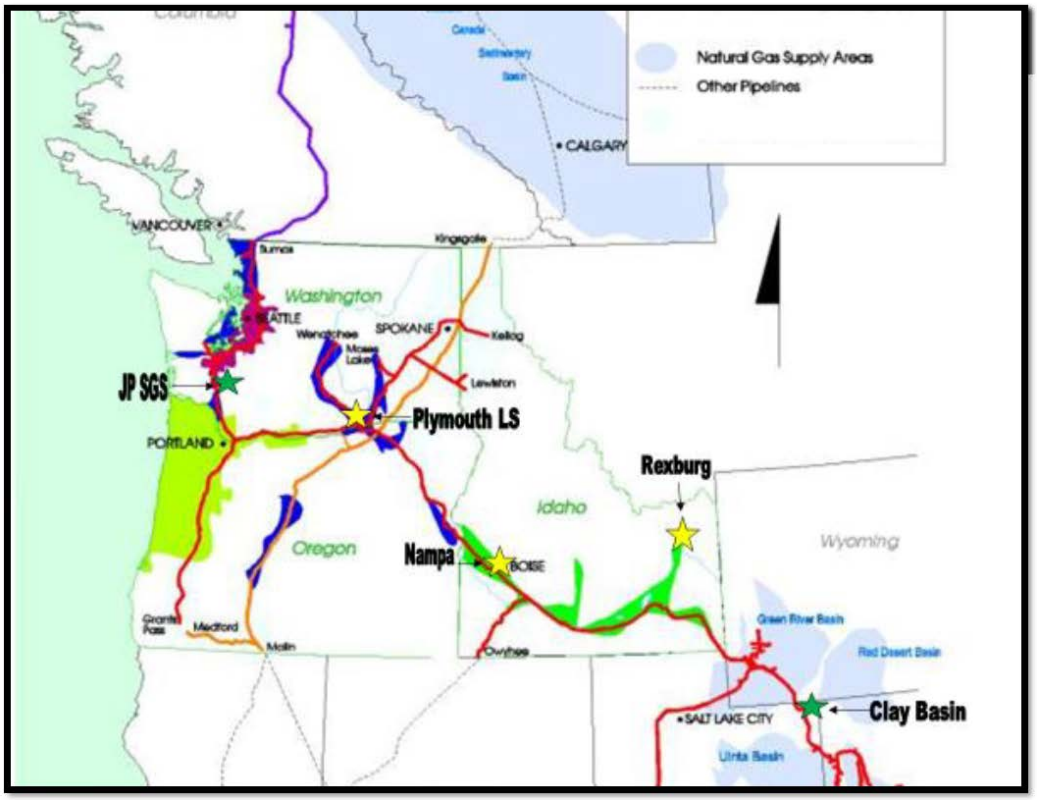


Figure 26: Intermountain Storage Facilities

Liquefied Storage

Liquefied storage facilities make use of a process that super cools and liquefies gaseous methane under pressure until it reaches approximately minus 260°F. LNG occupies only one-six-hundredth the volume compared to its gaseous state, so it is an efficient method for storing peak requirements. LNG is also non-toxic; it is non-corrosive and will only burn when vaporized to a 5-15% concentration with air. Because of the characteristics of liquid, its natural propensity to boil-off and the enormous amount of energy stored, LNG is normally stored in man-made steel tanks.

Liquefying natural gas is, relatively-speaking, a time-consuming process, the compression and storage equipment is costly, and liquefaction requires large amounts of added energy. It typically requires as much as one unit of natural gas burned as fuel for every three to four units liquefied. Also, a full liquefaction cycle may take five to six months to complete. Because of the high cost and length of time involved in filling a typical LNG facility, they are usually cycled only once per year and are reserved for peaking purposes. This makes the unit cost of the gas withdrawn somewhat expensive when compared to other options.

Vaporization, or the process of changing the liquid back into the gaseous state, on the other hand, is a very efficient process. Under typical atmospheric and temperature conditions, the natural state of methane is gaseous and lighter than air as opposed to the dense state in its liquid form. Consequently, vaporization requires little energy and can happen very quickly. Vaporization of LNG is usually accomplished by utilizing pressure differentials by opening and closing valves in concert with the use of some hot-water bath units. The high-pressure LNG is vaporized as it is warmed and is then allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and, as opposed to the long liquefaction cycle, a typical full withdrawal cycle may last 10 days or less at full rate. Because of the cost and cycle characteristics, LNG withdrawals are typically reserved for needle peaking during very cold weather events or for system integrity events.

Neither of the two LNG facilities utilized by Intermountain requires the use of year-round transportation capacity for delivery of withdrawals to Intermountain's customers. The Plymouth facility is bundled with redelivery capacity for delivery to Intermountain and the Nampa and Rexburg LNG tank withdrawals go directly into the Company's distribution system. The IRP assumes liquid storage will serve as a needle peak supply.

Underground Storage

This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities typically require less hardware compared to LNG projects and are usually less expensive to build and operate than liquefaction storage facilities. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. The lower costs allow for the more frequent cycling of inventory and in fact, many such projects are utilized to arbitrage variations in market prices.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, maximum daily injection levels are much higher, so a typical underground injection season is much shorter, typically lasting only three to four months. But the lower pressures also mean that maximum withdrawals are typically much less than liquefied storage at maximum withdrawal. So, it could take 35 days or more to completely empty an underground facility. The longer withdrawal period and minimal commodity costs make underground storage an ideal tool for winter baseload or daily load balancing, and therefore, Intermountain normally uses underground storage before liquid storage is withdrawn. Underground storage is not ideal for delivering a large amount of gas quickly, however, so LNG is a better solution for satisfying a peak situation.

Intermountain contracts with two pipelines for underground storage: Dominion Energy for capacity at its Clay Basin facility in northeastern Utah and NWP for capacity at its Jackson Prairie facility in Washington. Clay Basin provides the Company with the largest amount of seasonal storage and daily withdrawal. However, since Clay Basin is not bundled with redelivery capacity, Intermountain must use its year-round capacity when these volumes are withdrawn. For this

reason, the Company normally uses Clay Basin withdrawals during the November to March winter period to satisfy baseload needs.

Just like NWP's Plymouth LS facility, NWP's JP storage is bundled with redelivery capacity so Intermountain typically layers JP withdrawals between Clay Basin and its LNG withdrawals. The IRP uses Clay Basin as a winter baseload supply and JP is used as the first layer of peak supply. Table 10 below outlines the Company's storage resources for this IRP.

Table 10: Storage Resources

		Daily Withdrawal		Daily Injection		
Facility	Seasonal Capacity	Max Vol	% of 2019 Peak	Max Vol	# of Days	Redelivery Capacity
Nampa	580,000	60,000	14%	3,500	166	None
Plymouth	1,475,135	155,175	36%	7,721	191	TF-2
Subtotal Liquid	2,055,135	215,175	50%	11,221		
Jackson Prairie	1,092,099	30,337	7%	30,337	36	TF-2
Clay Basin	8,413,500	70,114	16%	69,857	120	TF-1
Subtotal Underground	9,505,599	100,451	23%	100,194		
Grand Total	11,560,734	315,626	73%	111,415		

All the storage facilities require the use of Intermountain's every-day, year-round capacity for injection or liquefaction. Because injections usually occur during the summer months, use of year-round capacity for injections helps the Company make more efficient use of its every-day transport capacity and term gas supplies during those off-peak months when the core market loads are lower.

Nampa LNG Plant

The primary purpose of the Nampa LNG plant is to supplement gas supply onto Intermountain Gas' distribution system. The Nampa LNG Plant can store up to 600 million cubic feet of natural gas in liquid form and can re-gasify back into Intermountain's system at a rate of approximately 60 million cubic feet per day.

During a needle peak event the plant is able to supplement supply during gas storage shortages or transportation restrictions into Idaho, and the plant has the added benefit of supplying natural gas directly into the connected Canyon County and Ada County distribution systems without use of interstate pipeline transportation, which eliminates another risk variable typically associated with gas supply. Compressed natural gas is not a feasible option for gas supply, thus making the plant a more valuable resource to the company.

The Nampa LNG plant typically performs liquefaction operations during non-peak weather times of the year, resulting in lower priced natural gas going into liquid storage, and providing potential cost savings when re-gasification occurs during peak cold weather events, gas supply shortages and interstate transportation restrictions.

Storage Summary

The Company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lesser extent, for system balancing. Intermountain believes that the geographic and operational diversity of the four facilities utilized offers the Company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the Company flexibility to determine its best use compared to other supply alternatives such as winter baseload or peak protection gas, price arbitrage or system balancing.

Interstate Pipeline Transportation Capacity

As discussed earlier, Intermountain is dependent upon firm pipeline transportation capacity to move natural gas from the areas where it is produced, to end-use customers who consume the gas. In general, firm transportation capacity provides a mechanism whereby a pipeline will reserve the right, on behalf of a designated and approved shipper, to receive a specified amount of natural gas supply delivered by that shipper, at designated receipt points on its pipeline system and subsequently redeliver that volume to delivery point(s) as designated by the shipper.

Intermountain holds firm capacity on four different pipeline systems including NWP. NWP is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system (other than Nampa LNG) via citygate taps with NWP. Table 11 on the next page summarizes the Company's year-round capacity on NWP (TF-1) and its storage specific redelivery capacity (TF-2). Between the amount of capacity Intermountain holds on the GTN, Foothills, and Nova pipelines and firm-purchase contracts at Stanfield, it controls enough capacity to deliver a volume of gas commensurate with the Company's Stanfield takeaway capacity on NWP. Upstream pipelines bring natural gas from the production fields in Canada to the interconnect with NWP.

Intermountain has historically contracted a portion of its firm transportation on NWP through long-term segmented capacity contracts with third parties. As those contracts near their expiration dates, Intermountain was able to negotiate contracts to replace the expiring capacity with firm NWP transportation capacity contracted directly between Intermountain and NWP. Additionally, Intermountain was able to extend its existing NWP transport agreements as well as its Plymouth storage agreements. Until the existing capacity expires in 2020 and 2025, Intermountain will hold some excess capacity. To mitigate this situation, Intermountain was able negotiate a reduced rate for the new capacity until the existing capacity expires. Intermountain also plans to release the capacity to willing buyers on a short-term basis. The capacity releases

will generate credits for Intermountain's customers that will help to additionally offset the costs of the capacity until the existing contracts expire. This capacity restructuring will allow Intermountain to continue to provide its customers the safe, reliable, and economically priced service they expect.

Table 11: Northwest Pipeline Transport Capacity

City Gate Delivery Quantity (MMBtu per day)	2019	2020	2021	2022	2023
TF-1 Capacity -					
Sumas Base Capacity	90,941	90,941	90,941	90,941	90,941
Sumas Segmentation and Release	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)
Sumas Winter Only Capacity	3,000	3,000	3,000	3,000	3,000
Stanfield Base Capacity	88,175	105,624	105,624	105,624	130,624
Stanfield Capacity Via Segmentation	90,941	90,941	90,941	90,941	90,941
Rockies	97,478	97,478	97,478	97,478	97,478
Total TF-1 Capacity	279,594	297,043	297,043	297,043	297,043
City Gate Supply	18,056	18,056	-	-	-
Total City Gate Delivery Before TF-2	297,650	315,099	297,043	297,043	297,043
TF-2 Capacity -					
Plymouth (LS)	155,175	155,175	155,175	155,175	155,175
Jackson Prairie (JP)	30,337	30,337	30,337	30,337	30,337
Total TF-2 Capacity	185,512	185,512	185,512	185,512	185,512
Nampa LNG (does not include Rexburg)	60,000	60,000	60,000	60,000	60,000
Total City Gate Delivery	543,162	560,611	542,555	542,555	542,555

Northwest Pipeline's facilities essentially run from the Four Corners area north to western Wyoming, across southern Idaho to western Washington. The pipeline then continues up the I-5 corridor where it interconnects with Spectra Energy, a Canadian pipeline in British Columbia, near Sumas, Washington. The Sumas interconnect receives natural gas produced in British Columbia. Gas supplies produced in the province of Alberta are delivered to NWP via Nova, Foothills and then GTN near Stanfield, Oregon. NWP also connects with other U.S. pipelines and gathering systems in several western U.S. states (Rockies) where it receives gas produced in basins located in Wyoming, Utah, Colorado and New Mexico. The major pipelines in the Pacific Northwest, several of which NWP interconnects with can be seen below (Figure 27).

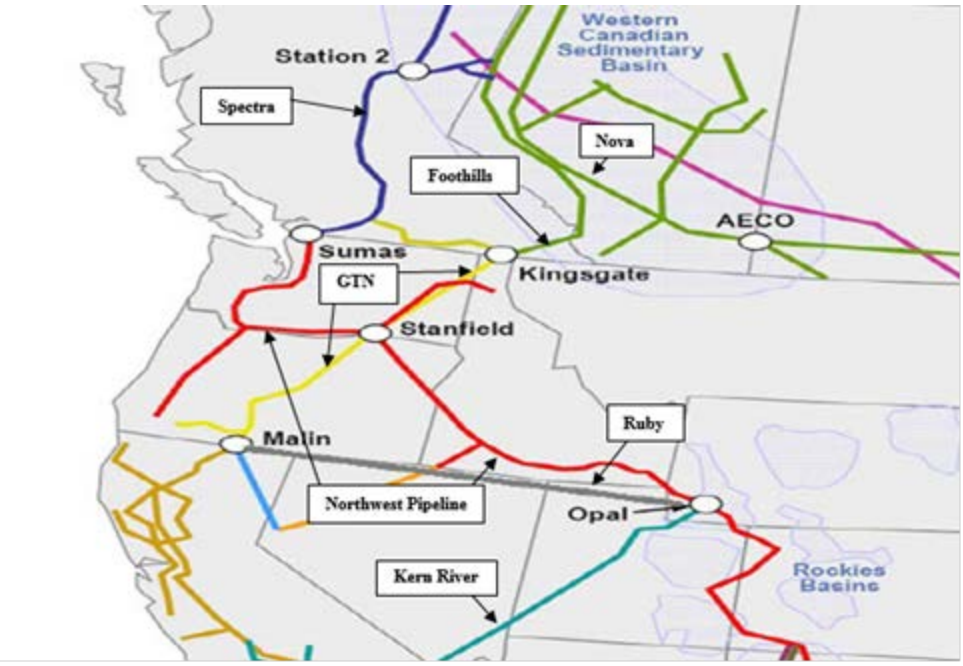


Figure 27: Pacific Northwest Pipelines Map

Because natural gas must flow along pipelines with finite flow capabilities, demand frequently cannot be met from a market's preferred basin. Competition among markets for these preferred gas supplies can cause capacity bottlenecks and these bottlenecks often result in pricing variations between basins supplying the same market area. In the short to medium term, producers in constrained basins invariably must either discount or in some fashion differentiate their product to compete with other also constrained supplies. In the longer run however, disproportionate regional pricing encourages capacity enhancements on the interstate pipeline grid, from producing areas with excess supply, to markets with constrained delivery capacity. Such added capacity nearly always results in a more integrated, efficient delivery system that tends to eliminate or at least minimize such price variances.

Consequently, new pipeline capacity - or expansion of existing infrastructure – in western North America has increased take-away capacity out of the WCSB and the Rockies, providing producers with access to higher priced markets in the East, Midwest and in California. Therefore, less-expensive gas supplies once captive to the northwest region of the continent, now have greater

access to the national market resulting in less favorable price differentials for the Pacific Northwest market. Today, wholesale prices at the major trading points supplying the Pacific Northwest region (other than Alberta supplies) are trending towards equilibrium. At the same time, new shale gas production in the mid-continent is beginning to displace traditionally higher-priced supplies from the Gulf coast which, from a national perspective, has been causing an overall softening trend in natural gas prices with less regional differentials.

Today, Intermountain and the Pacific Northwest are in an increasingly mega-regional marketplace where market conditions across the continent - including pipeline capacities - can, and often do, affect regional supply availability and pricing dynamics. Natural gas supplies are readily available today and pricing dynamics show a continued price softening in the short term with price stability or minimal price increases in the longer term. Alberta gas supplies continue to be very price competitive and Intermountain has contracted for its Alberta based supplies for now five-years into the future.

Supply Resources Summary

Because of the dynamic environment in which it operates, the Company will continue to evaluate customer demand to provide an efficient mix of supply resources to meet its goal of providing reliable, secure, and economic firm service to its customers. Intermountain actively manages its supply and delivery portfolio and consistently seeks additional resources where needed. The Company actively monitors natural gas pricing and production trends to maintain a secure, reliable and price competitive portfolio and seeks innovative techniques to manage its transportation and storage assets to provide both economic benefits to customers and operational efficiencies to its interstate and distribution assets. The IRP process culminates with the optimization model that helps to ensure that the Company's strategies to meet its traditional gas supply goals are based on sound, real-world, economic principles (see the Optimization Model Section beginning on page 86).

Capacity Release & Mitigation Process

Overview

Capacity release was implemented by FERC to allow markets to more efficiently utilize pipeline capacity. This mechanism allows a shipper with any unused capacity to auction the excess to another shipper that offers the highest bid. Thus, capacity that would otherwise sit idle can be used by a replacement shipper. The result is a more efficient use of capacity as replacement shippers maximize annualized use of existing capacity. One effect of maximizing the utilization of existing capacity is that pipelines are less inclined to build new capacity until the market recognizes that it is really needed and is willing to pay for new infrastructure. However, a more fully utilized pipeline can also mean existing shippers have less operational flexibility.

Intermountain has and continues to be active in the capacity release market. Intermountain has obtained significant amounts of unutilized capacity mitigation on NWP and GTN via capacity releases. The Company frequently releases seasonal and/or daily capacity during periods of reduced demand. Intermountain also utilizes a specific type of capacity release called segmentation to convert capacity from Sumas to Idaho into two paths of Sumas to Stanfield and Stanfield to Idaho. Intermountain uses the Stanfield to Idaho component to take delivery of the lower cost AECO gas supplies that are delivered by GTN to the interconnect with NWP at Stanfield. IGI Resources, Inc. (IGI) is then able to market the upper segment of Sumas to Stanfield to other customers.

Capacity release has also resulted in a bundled service called citygate, in which gas marketers bundle gas supplies with available capacity to be delivered directly to a market's gate stations. This grants additional flexibility to customers attempting to procure gas supplies for a specified period (i.e. during a peak or winter period) by allowing the customer to avoid contracting for year-round capacity which would not be used during off-peak periods.

Pursuant to the requirements under the Services Agreement between Intermountain and IGI, IGI is obligated to generate the maximum cost mitigation possible on any unutilized firm transportation capacity Intermountain has throughout the year. In performing this obligation, IGI must also insure that: 1) in no way will there be any degradation of firm service to Intermountain's residential and commercial customers, and 2) that Intermountain always has first call rights on any of its firm transportation capacity throughout the year.

With the introduction of natural gas deregulation under FERC Order 436 in 1985 and the subsequent FERC Orders 636, 712, 712A and 712B, the rules and regulations around capacity release transactions for interstate pipeline capacity were developed. These rules cover such activity as: 1) shipper must have title; 2) prohibition against tying arrangements and 3) illegal buy/sell transactions. These rules and regulations are very strict and must always be adhered to or the shipper is subject to significant fines (up to $1 million per day per violation) if ever violated.

The FERC jurisdiction interstate pipelines for which Intermountain holds capacity are NWP and GTN. To facilitate capacity release transactions, all pipelines have developed an Electronic

Bulletin Board (EBB) for which such transactions are to be posted. All released transportation capacity must be posted to the applicable pipeline EBB and in a manner that allows a competing party to bid on it.

Capacity Release Process

Over the past 10 to 15 years, IGI, because of its significant market presence in the Pacific Northwest, has been able to generate several millions of dollars per year in released capacity mitigation dollars on behalf of Intermountain for pass-back to its customers and to reduce the cost of unutilized firm transportation capacity rights. In this effort, IGI can determine what the appetite is in the competitive marketplace for firm transportation releases on NWP and GTN. It does this via direct communication with third parties or by market intelligence it receives from its marketing team as it deals with its customers throughout the region. However, the most effective way is using the EBB. IGI performs its obligation to Intermountain in one of two ways. First, if IGI itself is interested in utilizing any of Intermountain's unutilized firm transportation capacity, it determines what it believes is a market competitive offer for such and that is then posted to the EBB as a pre-arranged deal. As a pre-arranged deal, the transaction remains on the EBB for the requisite time and any third party has the opportunity to offer a higher bid. If this is done, then IGI can chose to match the higher bid and retain the use of the capacity, or not to match and the capacity will be awarded to the higher third-party bidder.

Second, if IGI is not interested in securing any unutilized capacity then it will post such capacity to the EBB as available and subject to open bidding by any third party. As such, the unutilized capacity will be awarded to the highest bidder. It should be noted that IGI posts to the EBB, as available capacity, certain volumes of capacity for certain periods every month during bid week. This affords the most exposure to parties which may be interested in securing certain capacity rights. However, to date, third parties have chosen to bid on such available capacity only a handful of times over all these years.

It should also be noted, that to protect the availability of firm transportation to Intermountain's residential and commercial customers during the year, all released capacity postings to the EBB, whether pre-arranged or not, are posted as recallable capacity. This means that Intermountain can recall the capacity at any time, if necessary, to cover its customer demand.

Non-Traditional Supply Resources

Non-traditional supply resources help supplement the traditional supply resources during peak demand conditions. Non-traditional supply resources consist of energy supplies not received from an interstate pipeline supplier, producer or interstate storage operator. Six non-traditional supply resources were considered in this IRP and are as follows:

1. Diesel/Fuel Oil
2. Coal
3. Wood Chips
4. Propane
5. Satellite/Portable LNG Facilities
6. Biogas Production

While a large volume industrial customer's load profile is relatively flat when compared to most residential and commercial customers, the Company's industrial customers are still a significant contributor to overall peak demand. However, some industrial customers have the ability to use alternate fuel sources to temporarily reduce their reliance on natural gas. By using alternative energy resources such as coal, propane, diesel and wood chips, an industrial customer can lower its natural gas requirement during peak load periods while continuing to receive the energy required for their specific process. Although these alternative resources and related equipment typically are available to operate any time during the year, most are ideally suited to run during peak demand from a supply resource perspective. However, only the industrial market has the capability to use any of the aforementioned alternate fuels in large enough volumes to make any material difference in system demand. More specifically, only industrial customers located along the Idaho Falls Lateral are able to use any of these non-traditional resources to offset firm demand throughout the Company's system. In order to rely on these types of peak supplies, Intermountain would need to engage in negotiations with specific customers to ensure availability. The overall expense of these kinds of arrangements is difficult to assess.

The remaining non-traditional resources, including satellite/portable LNG facilities and biogas production, are technically not a form of demand side management. However, satellite/portable LNG typically has the capability to provide additional natural gas supply at favorable locations within a potentially constrained distribution system. Satellite/portable LNG can therefore supplant the normal capacity upgrades performed on a distribution system by creating a new, portable supply point to maximize capacity possibilities. Biogas production could potentially supply a distribution system in a similar fashion, however, the location of a biogas facility, which

is determined by the producer, may not align with a constrained location of the distribution system, thus limiting its potential efficacy as a non-traditional supply resource.

Diesel/Fuel Oil

There are three large volume industrial customers along the IFL that currently have the potential to use diesel or fuel oil as a natural gas supplement. These customers are able to utilize onsite fuel storage tanks along with additional pipelines and equipment to switch their boilers over to burn oil and decrease a portion of their gas usage. Burning diesel or fuel oil in lieu of natural gas requires permitting from the local governing agencies, a process which can be lengthy depending on the specific type of fuel oil used, and also increases the level of emissions from the customer's plant.

Out of the three industrial customers that currently have equipment to burn fuel oil, only one customer has the ability to supplement its natural gas usage; the other two customers lack the ability to switch to diesel or fuel oil due to intentionally not renewing the requisite permits or choosing not to purchase and store fuel oil at their facility. The estimated capital cost to install a diesel storage system is approximately $200,000 - $500,000 depending on usage requirements and days of storage. The estimated cost of diesel or fuel oil is between $2.05 - $2.97 per gallon depending on fuel grade and classification, time of purchase and quantity of purchase. The conversion cost to natural gas is roughly $1.38 to $2.00 per therm.

Coal

Coal use is very limited as a non-traditional supply resource for firm industrial customers within Intermountain's service territory. In order to use coal to offset natural gas demand, an industrial customer must maintain a separate boiler dedicated to coal in addition to its natural gas boiler. The customer must also have additional equipment installed at its facility to transport the coal to the boiler. Regulations and permitting requirements can also be a challenge. Only three firm industrial customers remain on Intermountain's system that have the ability and requisite permitting to offset natural gas demand with coal.

The cost of coal in the Northwest is approximately $50 per ton, including transportation and depending on the quality of the coal. Lower BTU coal would range from 8,000 – 13,000 BTU per pound while higher quality coal would range from 12,000 - 15,000 BTU per pound. This translates into a per therm cost of coal of roughly $0.21, plus permitting and equipment operation and maintenance costs.

Wood Chips

Using wood chips as alternative fuel is a practice utilized by one large volume industrial customer on the IFL. In order to accommodate wood burning there must be additional equipment installed, such as wood fired boilers, wood chip transport and dry storage facilities. The wood is supplied from various tree clearing and wood mill operations that produce chips within regulatory

specifications to be used as fuel. The chips are then transported by truck to the location where the customer will typically utilize them as a fuel source for a few months each year. The wood fired boilers of this industrial customer are currently operated in conjunction with natural gas boilers, and technically would not offset natural gas usage. For comparison purposes, the wood fired boilers, if used to replace natural gas for this specific industrial customer, could offset gas usage by approximately 7,500 therms per day. Unfortunately, this single customer does not have the ability to utilize any more wood fuel than it is currently using.

The cost of wood continually changes based on transportation, availability, location and the type of wood processing plant that is providing the chips. Wood has a typical energy value of 5,000-6,000 BTU's per pound, which converts into 16-20 pounds of wood being burned to produce one therm of natural gas.

Propane

Since propane is similar to natural gas, the conversion to propane is much easier than a conversion to most other non-traditional supply resources. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce an industrial customer's natural gas needs by 100%. The use of propane requires onsite storage, additional gas piping and a reliable supply of propane to maintain adequate storage. Currently there are no industrial customers on the Company's system that have the ability to use propane as a feasible alternative to natural gas.

Capital costs for propane facilities can become relatively high due to storage requirements. Typical capital costs for a peak day send out of 30,000 therms per day, and the storage tanks required to sustain this load, are approximately $600,000 - $700,000. Storage facilities should be designed to accommodate a peak day delivery load for approximately seven days. The average cost of propane is roughly $2.50 per gallon, which is a natural gas equivalent to $2.69 per therm. [NOTE: One gallon of propane is approximately 91,600 BTU]. Fixed operation and maintenance costs are approximately $50,000 - $100,000 per year.

Biogas Production

Biogas can be defined as utilizing any biomass material to produce a renewable fuel gas. Biomass is any biodegradable organic material that can be derived from plants, animals, animal byproduct, wastewater, food/production byproduct and municipal solid waste. After processing of biogas to industry purity standards the gas can then be used as a renewable supplement to traditional natural gas within Company facilities.

Idaho is one of the nation's largest dairy producing states which make it a prime location for biogas production utilizing the abundant supply of animal and farm byproducts. Southern Idaho currently has multiple interested parties reviewing the prospect of constructing an anaerobic digester facility and becoming a gas supplier on Intermountain's distribution system. At this time,

there is one biogas production facility contracted to begin supplying renewable natural gas in 2019. Intermountain is also in communication with other potential producers within the service territory.

Satellite/Portable LNG Equipment

Satellite/portable LNG equipment allows natural gas to be transported in tanker trucks in a cooled liquid form thus allowing larger BTU quantities to be delivered to key supply locations throughout the distribution system. Liquefied natural gas has a tremendous withdrawal capability because the natural gas is in a denser state of matter. Portable equipment has the ability to boil LNG back to a gaseous form and deliver it into the distribution system by heating the liquid from -260 degrees Fahrenheit to a typical temperature of 50 – 70 degrees Fahrenheit. This portable equipment is available to lease or purchase from various companies and can be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG production plants and are dependent upon the specific location where the portable LNG equipment is to be placed. The available delivery pressure from LNG equipment ranges from 150 psig to 650 psig with a typical flow capability of approximately 2,000 - 8,000 therms per hour.

Intermountain Gas currently operates a portable LNG unit on the northern end of the Idaho Falls Lateral to assist in peak shaving the system. In addition to the portable equipment, Intermountain also has a permanent LNG facility on the IFL that is designed to accommodate the portable equipment, provide an onsite control building and allow onsite LNG storage. The ability to store LNG onsite allows Intermountain to partially mitigate the risk associated with relying on truck deliveries during critical flow periods. The LNG delivery risk is also reduced now that Intermountain has the ability to withdraw LNG from the Nampa LNG storage tank and can transport this LNG around the state in a timely manner. With Nampa LNG readily available, the cost and dependence of third-party supply is removed.

The cost of the portable LNG equipment is approximately $1 – $2.5 million with additional cost to either lease or purchase property to place the equipment and the cost of the optional permanent LNG facility. The fixed cost to lease the portable equipment is approximately $250,000 - $350,000 per month plus the cost of LNG.

Lost and Unaccounted For Natural Gas Monitoring

Intermountain Gas Company is pro-active in finding and eliminating sources of Lost and Unaccounted For (LAUF) natural gas. LAUF is the difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers. Intermountain is consistently one of the best performing companies in the industry with a three-year average LAUF percentage of .1176% (see Figure 28 below).

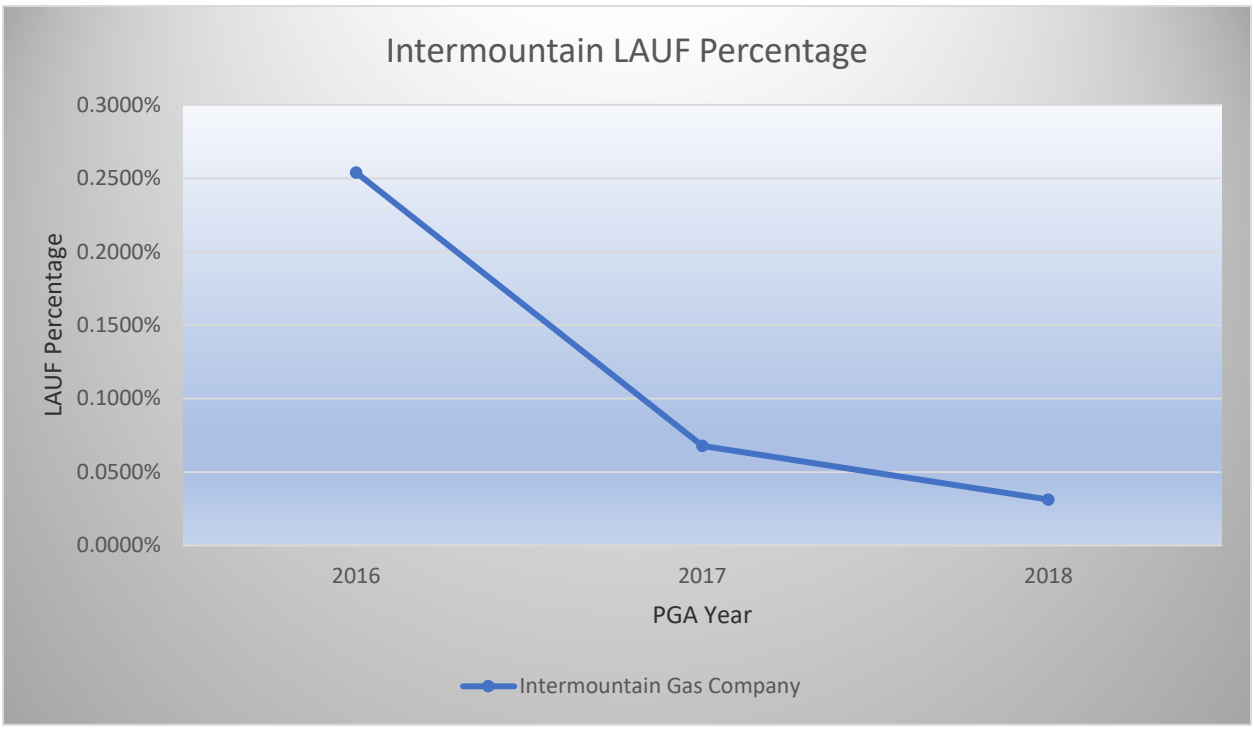


Figure 28: Intermountain LAUF Statistics

Intermountain utilizes a system to monitor and maintain a historically low amount of LAUF natural gas. This system is made up of the following combination of business practices:

- Perform ongoing billing and meter audits
- Routinely rotate and test meters for accuracy
- Conduct leak surveys on one-year and four-year cycles to find leaks on the system
- Natural gas line damage prevention and monitoring
- Implementing advanced metering infrastructure system to improve meter reading audit process
- Monitor ten weather location points to ensure the accuracy of temperature related billing factors

- Utilize hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors

Billing and Meter Audits

Intermountain conducts billing audits to identify low usage and zero usage with each billing cycle. Intermountain also works to ensure billing accuracy of newly installed meters. These audits are performed to ensure that the correct drive rate and billing pressure are programmed for the meter and billing system to avoid billing errors. Any corrections are made prior to the first bill going out.

Intermountain also compares on a daily and monthly basis its telemetered usage versus the metered usage that Northwest Pipeline records. These frequent comparisons enable Intermountain to find any material measurement variances between Intermountain's distribution system meters and Northwest Pipeline's meters.

Table 12: 2016 – 2018 Billing and Meter Audit Results

Billing and Meter Audit Results			
	2016	2017	2018
Dead Meters	413	457	310
Drive Rate Errors	9	12	4
Pressure Errors	30	7	24
Totals	452	476	338

Meter Rotation and Testing

Meter rotations are also an important tool in keeping LAUF levels low. Intermountain regularly tests samples of its meters for accuracy. Sampled meters are pulled from the field and brought to the meter shop for testing. The results of tests are evaluated by meter family to determine the pass/fail of a family based on sampling procedure allowable defects. If the sample audit determines that the accuracy of certain batches of purchased meters are in question, additional targeted samples are pulled and any necessary follow up remedial measures are taken.

In addition to these regular meter audits, Intermountain also identifies the potential for incorrectly sized and/or type of meter in use by our larger industrial customers. IGC conducts a monthly comparison to the billed volumes as determined by the customer's meter. If a discrepancy exists between the two measured volumes, remedial action is taken.

Leak Survey

On a regular and programmed basis, Intermountain technicians check Intermountain's entire distribution system for natural gas leaks using sophisticated equipment that can detect even the smallest leak. The surveys are done on a one-year cycle in business districts and a four-year cycle in other areas. This is more frequent than the legal requirement, which mandates leak surveys

on one-year and five-year cycles. When such leaks are identified, which is very infrequent, remedial action is immediately taken. Intermountain will repair found leaks typically within 60 days, which is more aggressive than the industry where lower grade leaks are often monitored for safety and not repaired immediately.

Damage Prevention and Monitoring

Unfortunately, human error leads to unintentional excavation damage to our distribution system. When such a gas loss situation occurs, an estimate is made of the escaped gas and that gas then becomes "found gas" and not "lost gas". To help eliminate instances of gas loss resulting from excavation damage, Intermountain is in the process of implementing a comprehensive damage prevention program to reduce the number of gas line damages.

Since the 2017 IRP was filed, Intermountain has added a full-time person to create and manage the Company's damage prevention program. The program focuses on education to both business and agencies that interact with Intermountain and the public. Industry education and awareness has centered around trainings with contractors, excavators and first responders. In 2018, 18 different trainings were held across Intermountain's service territory.

Intermountain also helped sponsor the development of a "Safe Excavator" app for iPhone and Android phones. This app provides quick access to vital information regarding Digline, or 811, processes and procedures. The app allows a contractor or excavator to request a locate ticket and also shows all the applicable rules and laws.

To educate the general public on the importance of calling 811 prior to any type of digging, Intermountain has participated in a variety of informational activities. The Company sponsored and staffed booths at events such as Buy Idaho, the Pocatello Environmental Fair, the Associated General Contractors golf tournament, and the Boise Hawks baseball games. Intermountain placed ads in Chamber of Commerce publications, the Associated General Contractors directory and city business directories. The Company also ran over 20,000 radio and TV spots in the Boise, Idaho Falls, and Twin Falls markets promoting the need to call 811 before digging.

The additional focus on education and awareness is having an impact. Intermountain has seen a decrease in incidents that damage facilities, and especially a decrease in incidents that cause gas loss. There is still work to do, however. There continues to be instances where the contractor or individual either does not call 811 before digging or calls but does not pay attention to the marking of the utility facilities. Continued focus on damage prevention by Intermountain as well as the support of the newly created Idaho Damage Prevention Board should help to further reduce the incidences of excavation damage and related gas loss in the future.

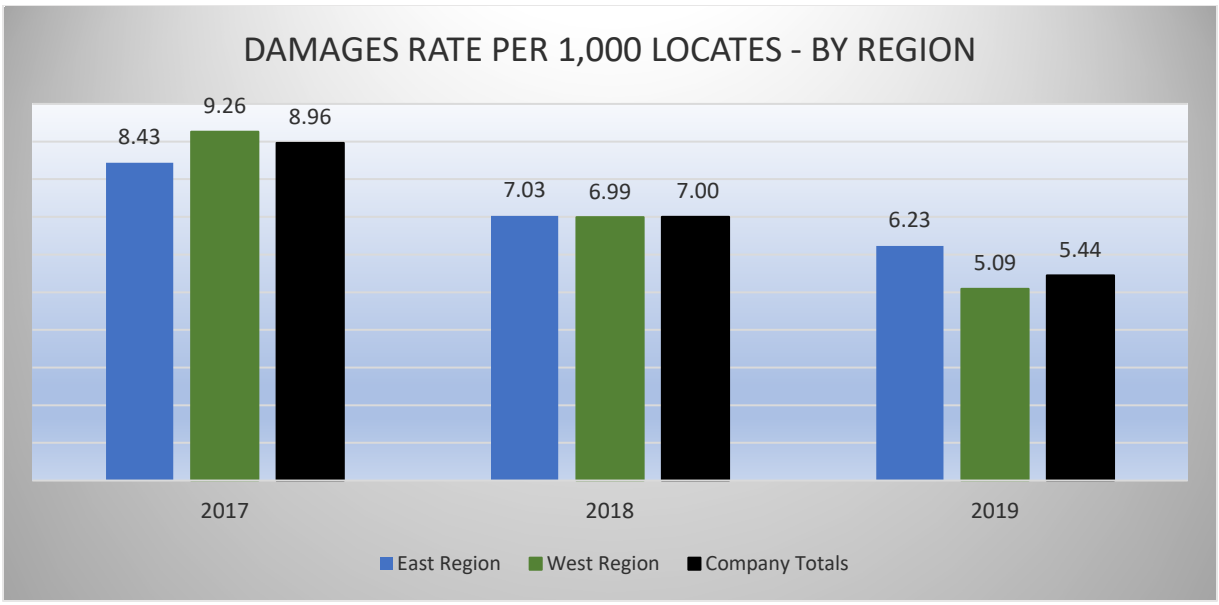


Figure 29: Intermountain Damages Rate Per 1,000 Locates – By Region

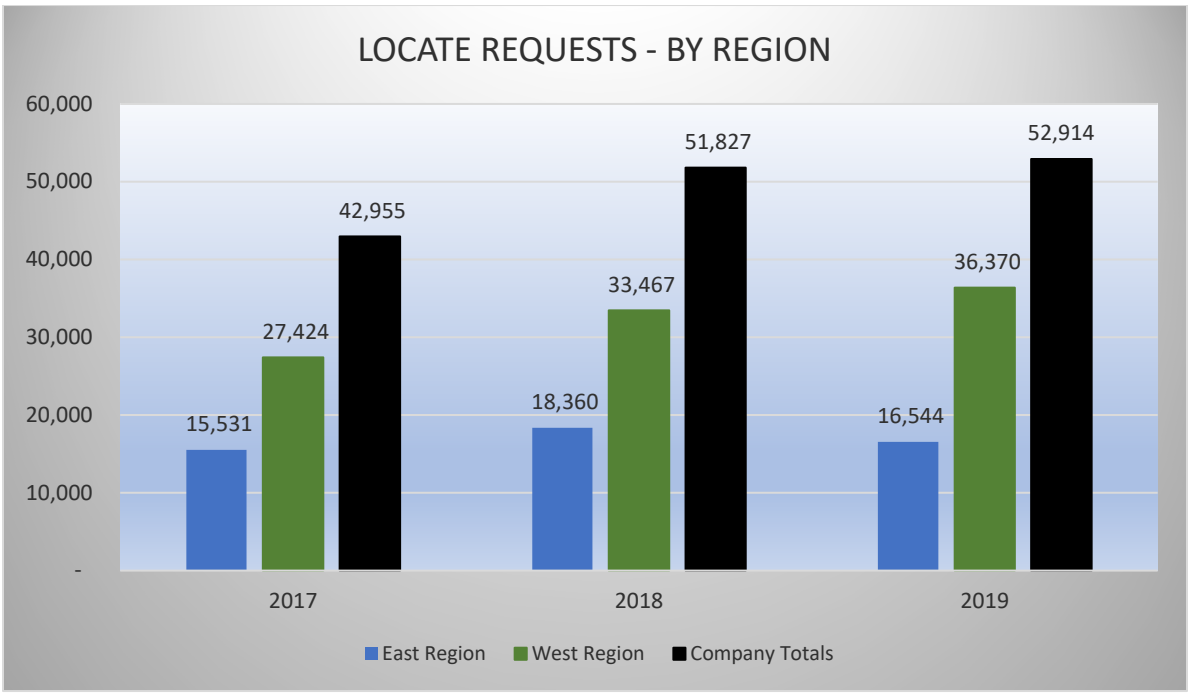


Figure 30: Intermountain Locate Requests – By Region

The figures above show the damage rate per 1,000 locates, and total locates for 2017 through 2019. The Figure 31 on the next page shows total damages by region and year for 2017 through 2019.

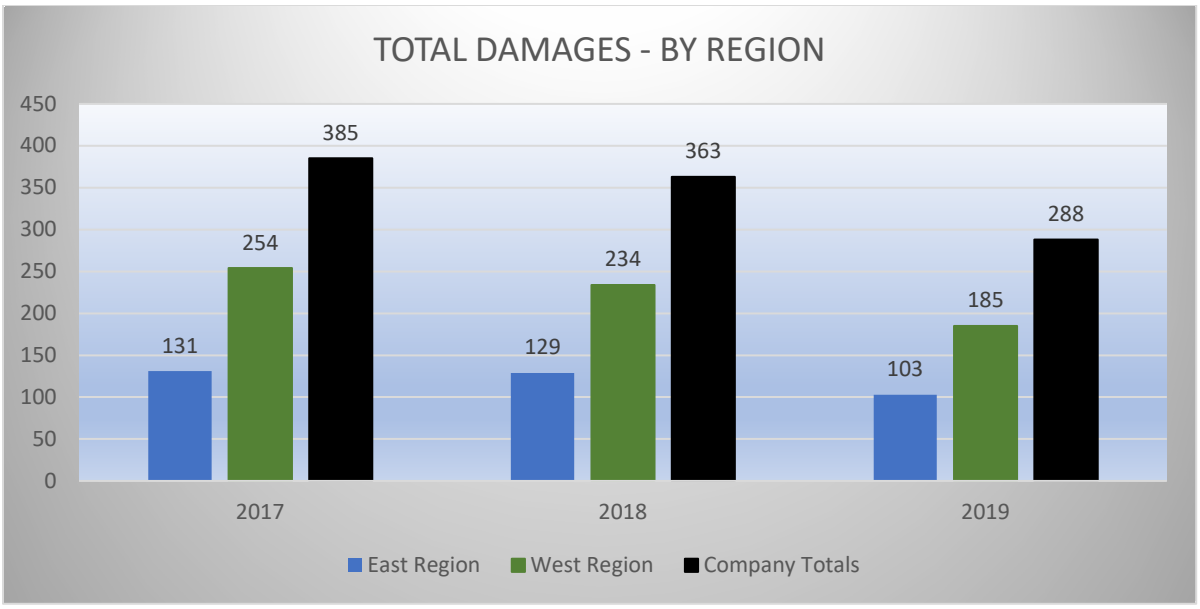


Figure 31: Intermountain Total Damages – By Region – Company

Advanced Metering Infrastructure

Intermountain is 50% complete with implementing Itron's fixed-network metering infrastructure, with a plan to complete the project by the end of 2020. This system utilizes a fixed mounted data collector using two-way communication to endpoints and to the repeater to collect on-demand reads and issue network commands. This system provides a robust collection of time-synchronized interval data, and when coupled with a meter data management system, it helps Intermountain:

- Improve customer service
- Refine forecasted consumption
- Manage and control tampering and theft
- Synchronize endpoint clocks to ensure data collected territory-wide is accurately time-stamped
- Retrieve missing interval data in the event of an outage
- Streamline the process to identify billing errors

Weather and Temperature Monitoring

Intermountain increased the number of weather monitoring stations in the early 2000's, from five to ten weather location points, to ensure the accuracy of temperature related billing factors. Additionally, Intermountain utilizes hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors. The weather and temperature monitoring provide for a better temperature component of the billing factor used to calculate customer energy consumption.

Summary

Intermountain continues to monitor LAUF levels and continuously improves business processes to ensure the company maintains a LAUF rate among the lowest in the natural gas distribution industry.

Core Market Energy Efficiency

As the cleanest, safest most affordable energy source available, why would we want consumers to use less natural gas? The wise use of our resources through high efficiency appliances and home construction helps individual customers save on their energy usage and monthly bill. The wise use of the commodity itself, and efficient use of the Intermountain Gas distribution system as a whole, benefits all of the Company's customers. Efficient use delays the need for expensive system upgrades while still allowing Intermountain to provide safe, reliable, affordable service to all customers.

From a corporate perspective, "At MDU Resources, we believe we have a responsibility to use natural resources efficiently and minimize the environmental impact of our activities." This is the Environmental Policy adopted by the Company on August 1, 1991, restated in 1998 and August 17, 2017. As a Company, our environmental goals are:

- To minimize waste and maximize resources
- To be a good steward of the environment while providing high quality and reasonably priced products and services; and
- To comply with or surpass all applicable environmental laws, regulations and permit requirements.

Market Transformation

The Gas Technology Institute (GTI) is our nation's leader in ongoing natural gas research, as well as the deployment and commercialization of new natural gas efficiency technologies. The goal of GTI is to solve important energy challenges while creating value in the marketplace. As part of this effort, GTI continues to perform important ongoing research and development work in the natural gas equipment arena through their Utilization Technology Development (UTD) group.

UTD is comprised of 20 member companies that serve more than 47 million natural gas customers in the Americas and Europe. UTD creates and advances products, systems, and technologies to save consumers money, save energy, integrate renewable energy with natural gas, and achieve safe, reliable, resilient end-user operation with superior environmental performance.

GTI uses funds contributed by member companies to leverage matching grants to make research dollars go further. Although not all research efforts are successful, Intermountain has participated in a number of projects that have reached the point of commercial viability. A sample of those projects includes:

Gas-fired Absorption Heat Pump (GAHP) for Space Heating or Commercial Water Heating

The GAHP can be used for space or water heating applications and is undergoing a four-unit field test in Wisconsin and Tennessee with prospective UTD manufacturing partner Trane and support from the U.S. Department of Energy, UTD and others. The GAHP has field-demonstrated an Annual Fuel Utilization Efficiency (AFUE) of 140%, with 45% gas savings, an estimated financial payback period of as low as three years, and ultra-low NOx emissions. The GAHP demonstrated continued operation under extreme cold weather conditions in Wisconsin during the January-February 2019 Polar Vortex.

Low NOx Advanced 3D-Printed Nozzle Burner

A novel design for next-generation retention nozzles leverages new additive manufacturing capabilities and equipment. In 2019, UTD is evaluating technology licensing applications in boilers and air heating. Laboratory tests to date have demonstrated an efficiency increase of 3-6% and a 50%-75% reduction in NOx emissions compared to current burners.

On-Demand Heat and Power System

This technology captures and stores renewable energy (or other resources, including waste heat), augments it with natural gas as needed, and delivers heat and power on-demand to commercial, industrial, and other users. In 2019, the technology is moving to a pilot field scale-up demonstration in California.

Self-Powered Tankless Water Heater

Tankless water heaters yield higher levels of efficiency than storage-type water heaters but require the added expense of an electrical connection and are susceptible to power outages unless a separate battery back-up system is installed. UTD researchers have assessed leading thermoelectric generator (TEG) technologies and, in 2019, are analyzing opportunities to economically integrate TEG and other technologies into a prototype water heater design.

High Efficiency Commercial Clothes Dryer

An advanced natural gas fired commercial clothes dryer is being created and demonstrated at laboratory scale that has the potential to save at least 50% of the energy used in the commercial clothes drying sector. It is being developed in partnership with Oak Ridge National Laboratory and others, with financial support from the U.S. Department of Energy and UTD.

This kind of research and development contributes to continued, market-transforming energy efficiency in the natural gas industry. Intermountain believes all customers benefit from investments in improving the efficiency of natural gas applications and technology improvements that reduce emissions.

Residential Energy Efficiency Program

The goal of Intermountain's Energy Efficiency program is to acquire cost-effective demand side resources. Unlike supply side resources, which are purchased directly from a supplier, demand side resources are purchased from individual customers in the form of unused energy as a result of energy efficiency. The demand side resources acquired through the Company's EE Program (also referred to as Demand Side Management or DSM) ultimately allow Intermountain to displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcement on the Company's distribution system. The Company strives to raise awareness about home energy efficiency and inspire customers to reduce their individual demand for gas through outreach and education.

Collections for funding the EE program began on October 1, 2017. Active promotion and staffing of the EE program launched in January 2018. During the 2017-2021 IRP, DSM therm savings were projected for the first five years of the program, as illustrated in the following chart (Figure 32).

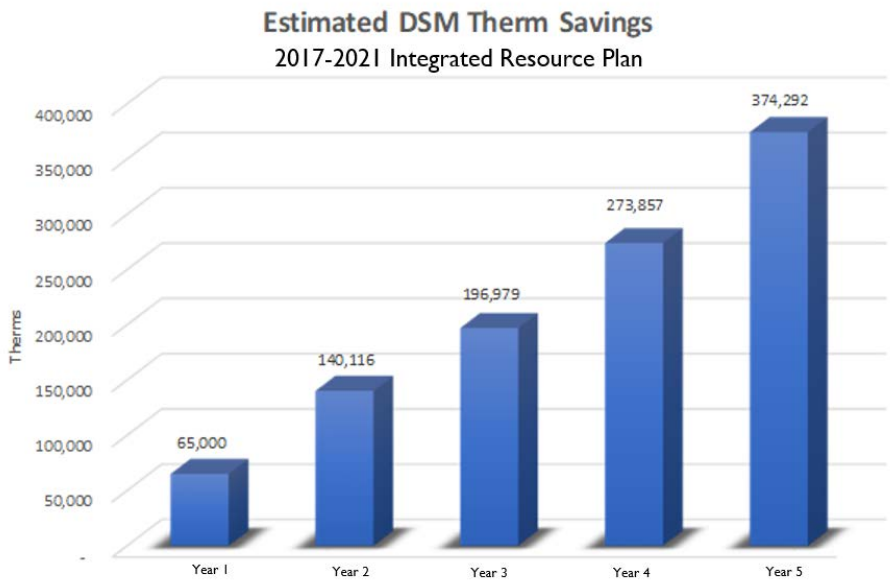
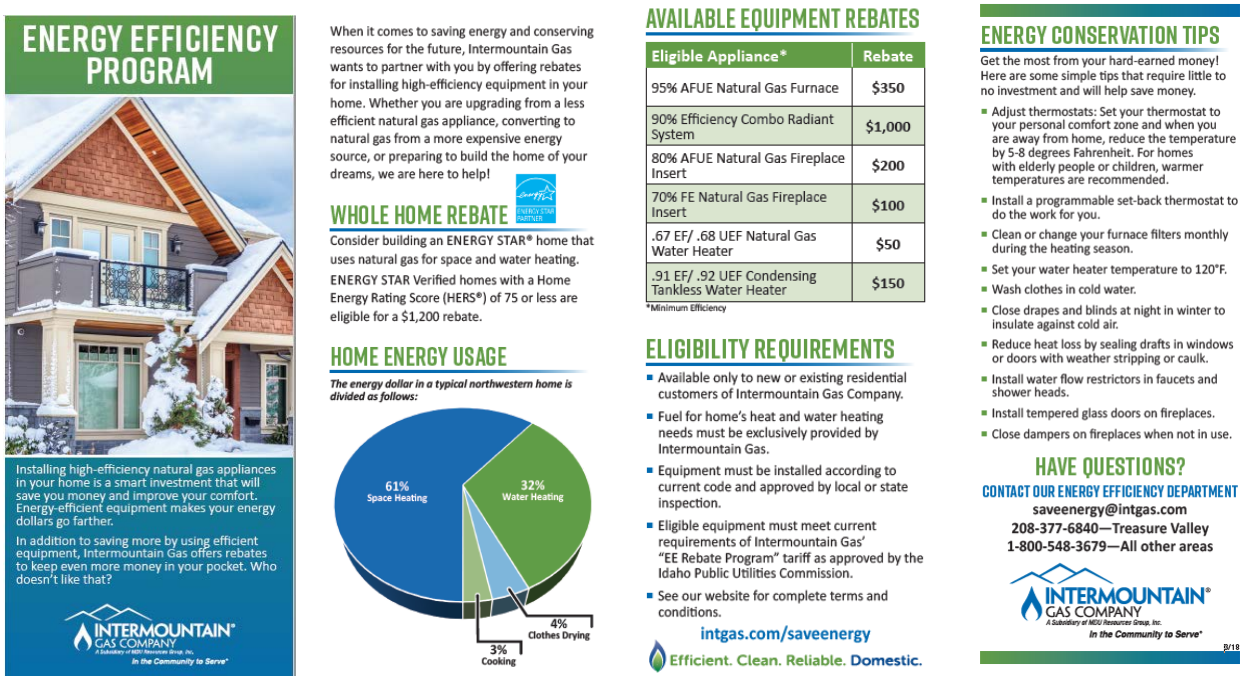


Figure 32: Estimated DSM Therm Savings

The initial program was intentionally designed to be a modest offering to allow for proper ramp up and promotion of the new program. The EE Program focused on two major rebate categories: appliance rebates for high-efficient natural gas appliances, and residential high-performance new construction with energy efficient design. Figures 33 and 34 are program brochures provided to customers though bill inserts in March 2018 and October 2018.



ENERGY EFFICIENCY PROGRAM

Installing high-efficiency natural gas appliances in your home is a smart investment that will save you money and improve your comfort. Energy-efficient equipment makes your energy dollars go farther.

In addition to saving more by using efficient equipment, Intermountain Gas offers rebates to keep even more money in your pocket. Who doesn't like that?

INTERMOUNTAIN® GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

When it comes to saving energy and conserving resources for the future, Intermountain Gas wants to partner with you by offering rebates for installing high-efficiency equipment in your home. Whether you are upgrading from a less efficient natural gas appliance, converting to natural gas from a more expensive energy source, or preparing to build the home of your dreams, we are here to help!

WHOLE HOME REBATE

Consider building an ENERGY STAR® home that uses natural gas for space and water heating. ENERGY STAR Verified homes with a Home Energy Rating Score (HERS®) of 75 or less are eligible for a $1,200 rebate.

HOME ENERGY USAGE

The energy dollar in a typical northwestern home is divided as follows:

61% Space Heating
32% Water Heating
4% Clothes Drying
3% Cooking

AVAILABLE EQUIPMENT REBATES

Eligible Appliance*	Rebate
95% AFUE Natural Gas Furnace	$350
90% Efficiency Combo Radiant System	$1,000
80% AFUE Natural Gas Fireplace Insert	$200
70% FE Natural Gas Fireplace Insert	$100
.67 EF/ .68 UEF Natural Gas Water Heater	$50
.91 EF/ .92 UEF Condensing Tankless Water Heater	$150

*Minimum Efficiency

ELIGIBILITY REQUIREMENTS

- Available only to new or existing residential customers of Intermountain Gas Company.
- Fuel for home's heat and water heating needs must be exclusively provided by Intermountain Gas.
- Equipment must be installed according to current code and approved by local or state inspection.
- Eligible equipment must meet current requirements of Intermountain Gas' "EE Rebate Program" tariff as approved by the Idaho Public Utilities Commission.
- See our website for complete terms and conditions.

intgas.com/saveenergy

Efficient. Clean. Reliable. Domestic.

ENERGY CONSERVATION TIPS

Get the most from your hard-earned money! Here are some simple tips that require little to no investment and will help save money.

- Adjust thermostats: Set your thermostat to your personal comfort zone and when you are away from home, reduce the temperature by 5-8 degrees Fahrenheit. For homes with elderly people or children, warmer temperatures are recommended.
- Install a programmable set-back thermostat to do the work for you.
- Clean or change your furnace filters monthly during the heating season.
- Set your water heater temperature to 120°F.
- Wash clothes in cold water.
- Close drapes and blinds at night in winter to insulate against cold air.
- Reduce heat loss by sealing drafts in windows or doors with weather stripping or caulk.
- Install water flow restrictors in faucets and shower heads.
- Install tempered glass doors on fireplaces.
- Close dampers on fireplaces when not in use.

HAVE QUESTIONS?

CONTACT OUR ENERGY EFFICIENCY DEPARTMENT
saveenergy@intgas.com
208-377-6840—Treasure Valley
1-800-548-3679—All other areas

INTERMOUNTAIN® GAS COMPANY
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In the Community to Serve®

B/18

Figure 33: Energy Efficiency Program Brochure – March 2018

NO PLACE LIKE *HOME*.
Energy Efficiency Program

INTERMOUNTAIN® GAS COMPANY
A Subsidiary of MDU Resources Group, Inc.
In the Community to Serve®

Energy Efficiency

YOUR COMFORT ZONE.
Natural gas provides the amenities that make us feel at home. Installing energy efficient solutions saves you money and makes your home more comfortable year-round. Along with monthly bill savings, you can earn rebates by installing qualified, high-efficiency natural gas appliances.

www.intgas.com/saveenergy

MAKE YOURSELF AT *HOME*.

Replace your furnace with an energy-efficient, gas furnace for warm comfortable air.
Pro tip: Clean or change your furnace filters monthly during the heating season to keep your furnace operating at peak efficiency.

Cozy up by a mess-free, high-efficiency gas fireplace.
Pro tip: Reduce leaks and drafts through comprehensive air sealing, quality-installed insulation, and high-performance windows and doors.

Enjoy an abundant supply of warm water when you upgrade to a high-efficiency, natural gas water heater.
Pro tip: Set your water heater temperature to 120 degrees Fahrenheit to maximize energy efficiency.

Find rebate details and more tips at www.intgas.com/saveenergy.

YOUR NEXT *HOME*.
Buying a home? Look for the little label with a big message on the circuit breaker box. The ENERGY STAR® Certified label ensures your home has been independently verified to meet high standards for energy efficiency, giving you peace of mind.

Figure 34: 2018 Energy Efficiency Customer Bill Insert – October 2018

Intermountain has assembled a Stakeholder group to provide input on the EE Program. The group met in November of 2018 and again in May of 2019. These meetings provide an opportunity for Intermountain to receive feedback on the current program's design and delivery. It also serves as a forum to discuss future program plans.

The EE Program is currently half-way through Program Year 2, and has invested in a more robust analysis of DSM resources for future program planning, including a modeling process by which DSM measures are selected based on cost-effectiveness, an explanation and update of avoided costs, and an explanation of the impact of DSM on supply and capacity needs.

Conservation Potential Assessment

In order to conduct a more robust analysis of all cost-effective DSM measures, Intermountain contracted with a third party to perform a Conservation Potential Assessment (CPA). The CPA is intended to support both short-term energy efficiency planning and long-term resource planning activities.

As outlined in the CPA report, the intent of the CPA is that it be used for:

- **Resource planning**: evaluate the impact of energy efficiency, fuel switching and codes and standards on long-term energy consumption and demand needs
- **Identify opportunities**: assess achievable DSM opportunities to improve DSM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential
- **Efficiency program planning**: inform portfolio and program design considering funding level, market readiness and other constraints

In April of 2018, IGC sent a Request for Proposal (RFP) to 30 companies to conduct a CPA. After receiving six proposals, and interviewing three companies, Dunsky Energy Consulting (Dunsky) was retained to perform the assessment. Dunsky utilized the expertise of GTI, the leading natural gas energy and environmental research, development and training organization, as the primary research lead for the study. The scope of the study included conservation potential for both the residential and commercial sectors, over the 2020-2039 time period.

The purpose of the potential assessment was "to provide a realistic, high-level, assessment of the long-term energy efficiency potential that is technically feasible, cost-effective, and achievable through efficiency programs." Three categories of potential savings, depicted in Figure 35, were examined by applying economic considerations such as market barriers and cost tests. The Utility Cost Test (UCT) was applied to the theoretical maximum savings opportunity, or the technical savings category, to screen for only the cost-effective measures, resulting in the economic savings potential. The economic savings potential of cost-effective measures was further screened by applying market barriers to establish the achievable energy efficiency potential. To

study the impacts on achievable potential savings, three different scenarios were tested: the low case, the base case and the max case.

Technical: Theoretical maximum savings opportunity, ignoring constraints such as cost-effectiveness and market barriers.

Economic: Applies economic considerations to technical potential, leaving only measures that are cost-effective. Screened on the Utility Cost Test (UCT).

Achievable: Applies market barriers to economic potential, resulting in an estimate of savings that can be achieved through efficiency program. Different scenarios are tested to examine their impacts on savings.

Figure 35: Categories of Potential Savings

Details of the three scenarios and the key insights to be examined with each scenario were as such:

- Low Case -applies low incentive levels, (35% of incremental measure costs), but with no budget constraints and over a broad set of cost-effective measures

  Key insight: *What level of saving can be achieved with a comprehensive offer, with incentives that are in the lower range?*

- Base Case – incentives increased to 50%, barrier reduction in Program Year 6, unconstrained budget – standard program approach

  Key insight: *How much more savings can be expected with increased incentive levels?*

- Maximum Case – incentive levels at 65%, barrier-reducing program delivery, unconstrained budget and measures

  Key Insight: *How would improved program delivery increase savings (e.g. consumer education, contractor training and support, etc.)*

The following chart (Figure 36) illustrates the cumulative technical, economic and achievable energy savings potential for the 2020-2039 period. The low, base, and max scenarios for achievable potential savings is also shown.

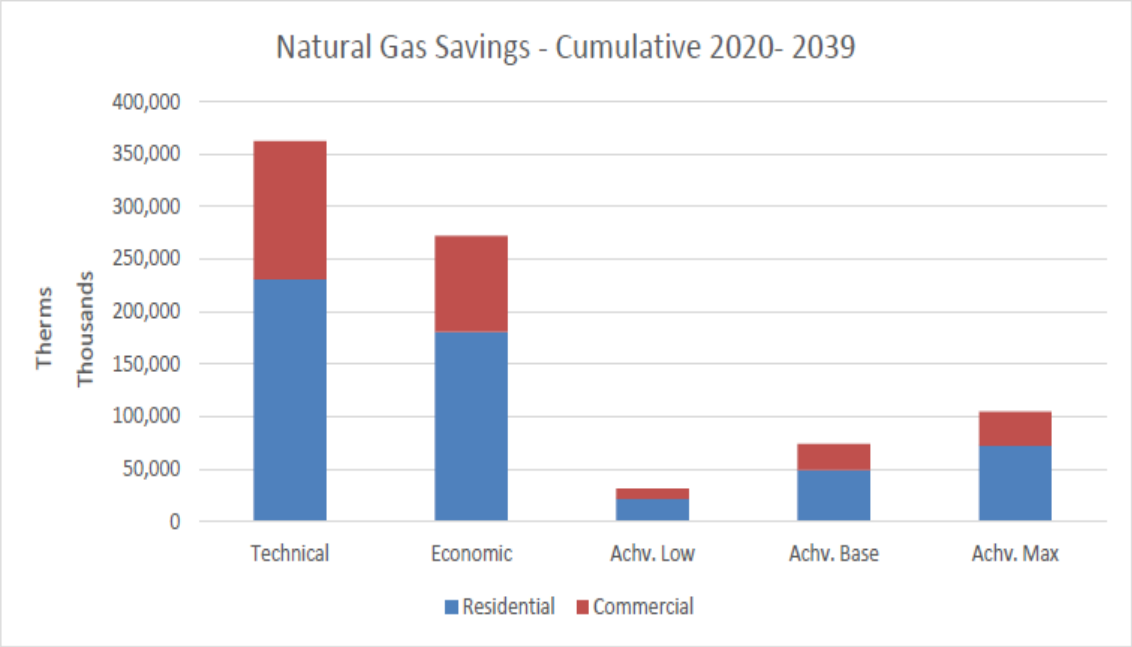


Figure 36: Natural Gas Savings – Cumulative 2020 - 2039

Base Scenario cumulative savings are illustrated in Figure 37, with attention on the first five-year period utilized in the IRP load forecast.

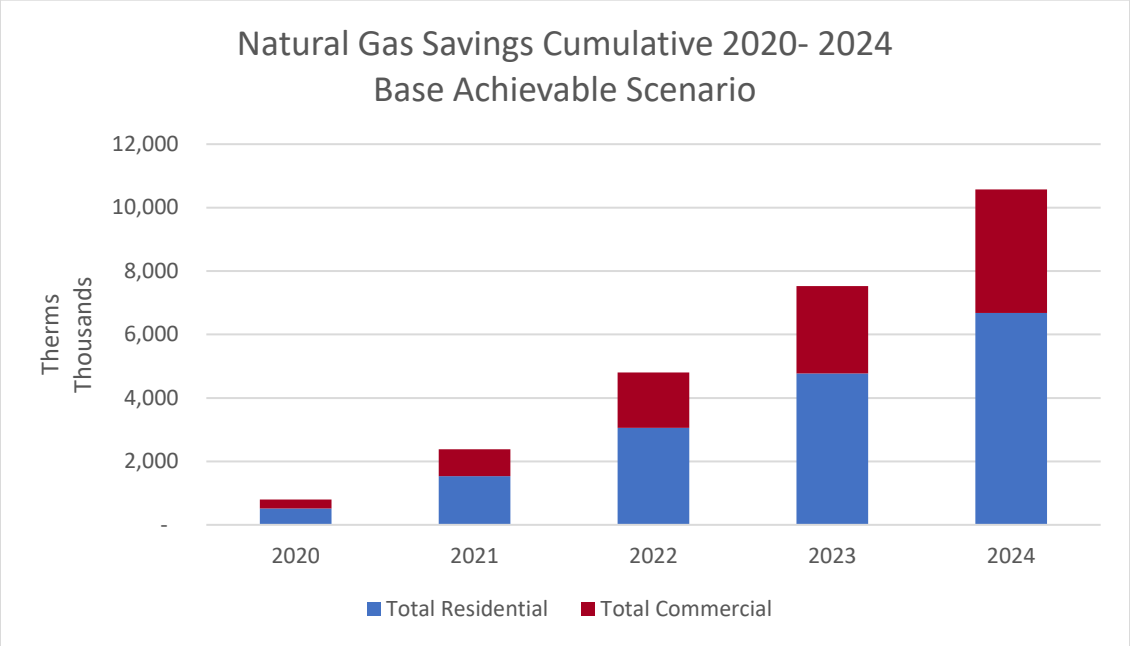


Figure 37: Natural Gas Savings Cumulative 2020 – 2024, Base Achievable Scenario

The base case scenario of the achievable potential energy savings estimates 41% of savings will come from HVAC, 32% from building envelope measures, and 27% from hot water measures for the residential sector during 2020-2024 program years. Likewise, the commercial sector is

estimated to contribute 78% of potential energy savings from HVAC, 12% from kitchen measures, 8% from hot water, and 2% from various other commercial applications for the same time period.

For the 2020-2024 program years, the portfolio is projected to be cost-effective based on both the Utility Cost Test and the Total Resource Cost Test, see Table 13 below.

Table 13: Intermountain Portfolio Cost-Effectiveness Under UCT and TRC Tests

Sector	UCT			TRC		
	Low	Base	Max	Low	Base	Max
Residential	1.78	1.74	1.46	1.33	1.36	1.31
Commercial	2.40	2.21	1.81	1.53	1.49	1.38
Total	**1.97**	**1.90**	**1.33**	**1.40**	**1.41**	**1.33**

Findings specific to the first-five years of the study will require significant consideration:

- Savings in the low and base scenarios exhibit strong growth in the first five years followed by modest growth in the subsequent years of the study. Rapid growth in the first time period is attributed to expansion of residential offerings and introduction of new initiatives in the commercial sector.
- Savings under the base scenario are 40% higher than the low scenario in the first five years. The base scenario budget is more than double the low scenario budget, as higher incentive levels increase the costs of all savings. Despite the higher average cost per therm of savings in the base scenario, under the UCT, all savings are cost-effective.
- Efficiency measures provide a stable flow of gas savings. Savings as a percent of forecasted volumes remain close: 0.5% for the low case and 1% for the base case scenario.
- Under the base scenario, budgets need to increase significantly. First, as customers participate in greater numbers, and then as participation further grows due to strategies to address market barriers and increase participation.

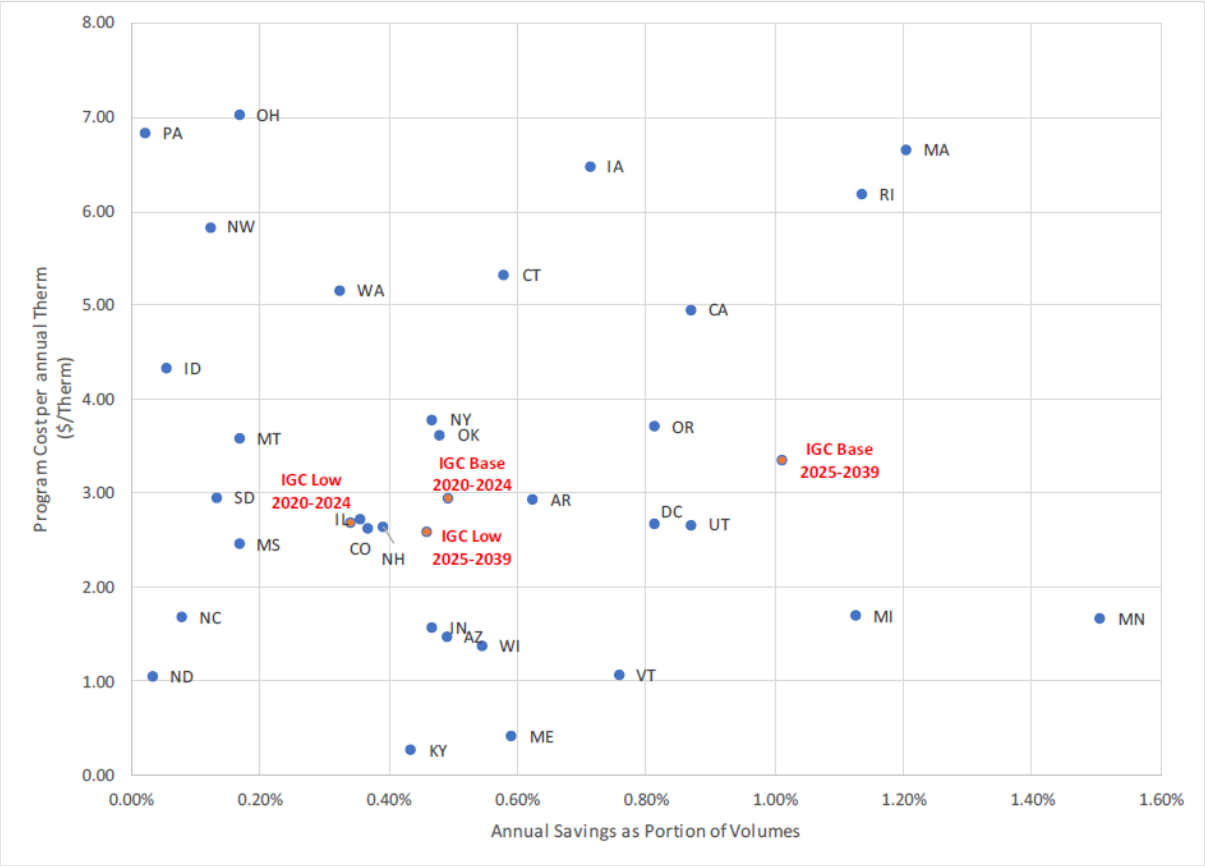


Figure 38: Intermountain's Portfolio Annual Savings Compared to Other Utilities

As seen in the chart above, a common metric to benchmark Intermountain's program against other jurisdictions is conducted by dividing the annual budget by first year savings. This metric does not consider the total savings for the complete measure lives and should not be compared with avoided costs, but it does still provide some key comparative insights. Low and base scenario savings and unit costs would place Intermountain among average utilities with savings ranging between 0.4 and 0.6%. With investments and sustained growth in the retrofit market, under the base scenario, Intermountain could evolve into one of the leading utilities, while maintaining costs at a reasonable level.

Savings potential from the base scenario were incorporated as a DSM resource in the Optimization model. Complete CPA results have been provided as Exhibit 4.

Large Volume Energy Efficiency

Through discussions with the customers and the information provided via the surveys, it is apparent that maximizing plant efficiency by optimizing production volumes while using the least amount of energy is a very high priority for the owners, operators, and managers of these large volume facilities. Nearly 20 years ago Intermountain developed an informational tool using SCADA and remote radio telemetry technology to gather, transmit and record the customer's hourly therm usage data. This data is saved on an internal server and provided to customers and their marketers/agents via a password protected website.

Usage data is useful in tracking and evaluating energy saving measures, new production procedures or new equipment. To deploy this tool, Intermountain installs SCADA units on customers' meters to records the meter volume each hour. That data is then transmitted via radio/telemetry communication technology to Intermountain's servers so it can be made available to customers.

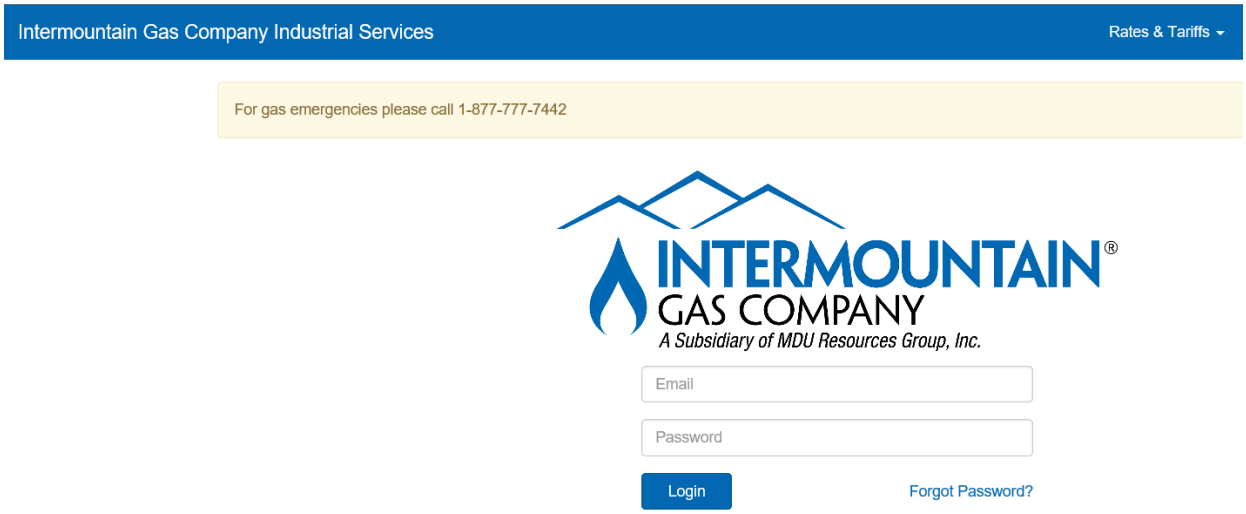


Figure 39: Large Volume Website Login

In order to provide customers access to this data, Intermountain has designed and hosts a Large Volume website, which is pictured in the figure above. The website is available on a 24/7 basis for Large Volume customers to log-in via the internet using a company specific username and customer managed password. After a successful log-in, the user immediately sees a chart showing the last 30 days of hourly usage for the applicable meter or meters, but also has the option to adjust the date range to see just a few hours or up to several years of usage data. An example of a month's worth of data is provided in the Figure 40. The user can also download the data in CSV format to review, evaluate, save and analyze natural gas consumption at their specific facility on an hourly, weekly, monthly, and annual basis as far back as 2015. Each customer may elect to have one or multiple employees access the site. Logins can also be created to make this same data available to a transport customer's natural gas marketer.

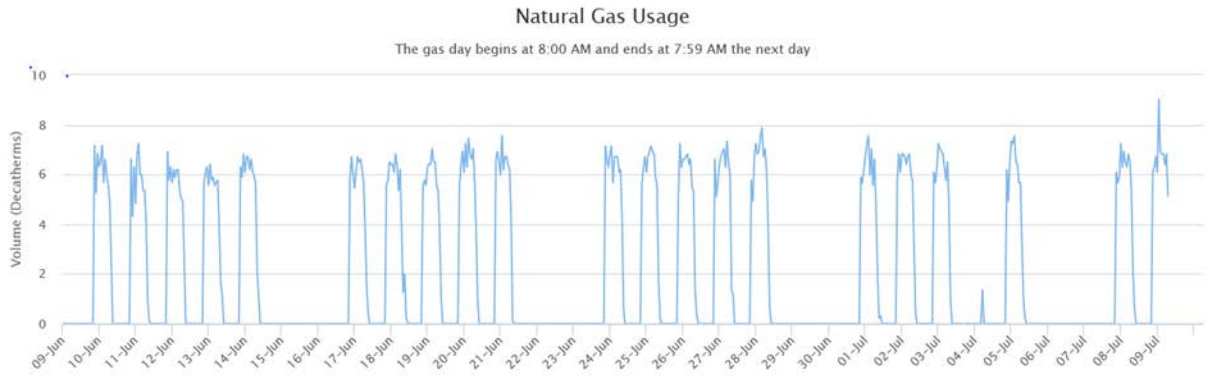


Figure 40: Natural Gas Usage History

The website also contains a great deal of additional information useful to the Large Volume customer. Customers can access information such as the different tariff services offered, answers to frequently asked questions and a potential marketer list for those interested in exploring transport service. The customer is also provided a "Contact Us" link and, in order to keep this site in the most usable format for the customer, a website feedback link is provided (see Figure 41). The site allows the Company to post information regarding things such as system maintenance, price changes, rate case information and anything else that might assist the customer or its marketer.

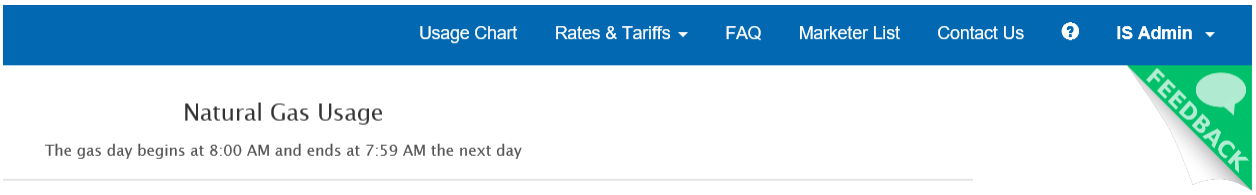


Figure 41: Feedback Link

Avoided Costs

Overview

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

This section presents IGC's avoided cost forecast and explains how it was derived. While the IRP is only a five-year plan, avoided costs are forecasted for 45 years to account for the full measure life of some conservation measures, such as ENERGY STAR certified homes, which have lives much longer than five years. The avoided cost forecast is based on the performance of IGC's portfolio under expected conditions.

Cost Incorporated

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

$$AC_{nominal} = TCF + TCV + CC + DSC$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year.
- TCF = Fixed Transportation Costs
- TCV = Variable Transportation Costs
- CC = Commodity Costs
- DSC = Distribution System Costs

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

- The most recent forecast of commodity prices by gas hub utilized in the 2019 IRP.
- The inflation rate used is tied to the Consumer Price Index (CPI) and is 2.0%.
- The nominal discount rate of 6.68% is IGC's tax effected cost of capital.
- Northwest Pipeline rates are utilized since these are used for the majority of Intermountain's transport and are most transparent.
- Standard present value and levelized cost methodologies are utilized to develop a real and nominal levelized avoided cost by year.

Understanding Each Component

Fixed Transportation Costs

Fixed transportation costs are the cost per therm that Intermountain pays for the right to move gas along an interstate pipeline. As is implied by the name, this cost is incurred whether gas flows along a pipeline or not. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reached through settlement or hearing) must be approved by the Federal Energy Regulatory Commission (FERC). To model rate increases in its forecast, Intermountain multiplies its transportation costs by the CPI escalator. For its 2019 IRP, Intermountain assumes that contracts thru 2025 are already committed and so not avoidable. Starting in 2026, the unit cost of the NWP capacity inflated to nominal cost by the inflation rate is utilized.

Variable Transportation Costs

Variable transportation costs are the cost per therm that Intermountain pays only if the Company moves gas along a pipeline. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reached through settlement or hearing) must be approved by FERC. The current rates for NWP TF-1 variable costs are utilized and escalated by the inflation rate.

Commodity Costs

Commodity costs are the costs of acquiring one therm of gas. Since Intermountain does not know where it will purchase the next therm of gas, the max from all three basins from which Intermountain purchases gas is utilized (AECO, Sumas and Rockies). The price forecast went through 2036 and then an escalator was applied through the remainder of the forecast period.

Distribution System Costs

Distribution system costs capture the costs of bringing gas from the transportation pipeline's citygate to Intermountain's customers. For this IRP cycle, IGC calculates distribution system costs as its system weighted average of its authorized margins. These costs are inflated by the CPI escalator every year.

Optimization

Distribution System Modeling

A natural gas pipeline is constrained by the laws of fluid mechanics which dictate that a pressure differential must exist to move gas from a source to any other location on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a pipeline system, typically during the operation of natural gas equipment, then the pressure in the system at that point becomes lower than the supply pressure in the system. This pressure differential causes gas to flow from the supply pressure to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to Intermountain's distribution systems. It is important that engineers design a distribution system in which the beginning pressure sources, which could be from interstate pipelines, compressor stations or regulator stations, have adequately high pressure, and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity, which is constrained by minimum pressure allowances at a determined point or points along the distribution system, and maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain size and length within specified operating pressures. The laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever-changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and distribution system can be ascertained for any set of known gas demand data. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day.

In order to evaluate intricate pipeline structures a system model is created to assist Intermountain's engineering team in determining the flow capacity and dynamics of those pipeline structures. For example, before a large usage customer is incorporated into an existing distribution system, the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipated future customer growth.

Modeling Methodology

Intermountain utilizes a hydraulic gas network modeling and analysis software program called Synergi Gas, distributed and supported by DNV GL, to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program individual models have been created for each of Intermountain's various distribution systems including high pressure laterals, intermediate pressure systems, distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Intermountain defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in the system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. The entire pipeline system is broken into three individual models for ease of use and to reduce the time requirements during a model run analysis. The largest model in use consists of approximately 71,000 active nodes, 580,000 graphic nodes and 75,600 facilities which are used along with additional model inputs to solve simultaneous equations through an iterative process, calculating pressures for over 70,000 unknown locations prior to analysis.

Synergi can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time, which more closely simulates real life operations which utilize gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this IRP, Intermountain can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost-effective methods of enhancing the constrained location. The feasibility, timeline, cost and increased capacity for each theoretical system enhancement is determined and then run through the IRP Optimization Model.

Potential Capacity Enhancements

Capacity enhancements within the Company's distribution system improve the ability to flow gas during periods of peak demand. Three capacity upgrades were considered in this IRP and are as follows:

1. Pipeline Loop
2. Pipeline Uprate
3. Compressor Station

The three capacity upgrades discussed below do not reduce demand nor do they create additional supply points, rather they increase the overall capacity of a pipeline system while utilizing the existing gate station supply points. When selecting capacity upgrades, a multitude of factors were considered including cost, maintenance and operation, growth, etc.

Pipeline Loop

Pipeline looping is a traditional method of increasing capacity within an existing distribution system. The loop refers to the construction of new pipe parallel to an existing pipeline that has, or may become, a constraint point. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, or steep and rocky terrain can greatly increase the cost to unjustifiable amounts when compared with alternative enhancement solutions.

The potential increase in system capacity by constructing a pipeline loop is dependent on the size and length of new pipe being installed, with typical increases in capacity ranging from 50,000 – 250,000 therms per day on large, high pressure laterals. The cost for a new pipeline installation of this magnitude is generally in the range of $7 - $20 million.

Pipeline Uprate

A quick and sometimes relatively inexpensive method of increasing capacity in an existing pipeline is to increase the maximum allowable operating pressure of the line, usually called a pipeline uprate. Uprates allow a company to maximize the potential of their existing systems before constructing additional facilities and are normally a low-cost option to increase capacity. However, leaks and damages are sometimes found or incurred during the uprate process creating costly repairs. There are also safety considerations and pipe regulations that restrict the feasibility of increasing the pressure in any pipeline, such as the material composition, strength rating and relative location of the existing pipeline.

Compressor Station

Compressor stations are typically installed on pipelines or laterals with significant gas flow and the ability to operate at higher pressures. Intermountain currently has two such transmission pipelines for which the installation of a compressor station could be practical: the Sun Valley Lateral and the Idaho Falls Lateral. Regulatory and environmental approvals to install a compressor station, along with engineering and construction time, can be a significant deterrent, but compressors can also be a cost effective, feasible solution to lateral constraint points. Compressor stations can be broken down into the following two scenarios:

A single, large-volume compressor can be installed on the pipeline when there is a constant, high flow of gas. The compressor is sized according to the natural gas flow and is placed in an optimal location along the lateral. This type of compressor will not function properly if the flow in the pipeline has a tendency to increase or decrease significantly. This type of station can have a price range of $3 - $6 million plus land, and typical operating and maintenance costs will range between $100,000 - $200,000 annually.

The second option is the installation of multiple, smaller compressors located in close proximity or strategically placed in different locations along a lateral. Multiple compressors are very beneficial as they allow for a large flow range, have some redundancy and use smaller and typically more reliable drivers and compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time. This “just in time” approach allows a pipeline to serve growing customer demand for many years into the future while avoiding the more costly purchase of a single, larger station. However, high land prices or the unavailability of land may render this option economically or operationally infeasible. The cost of a smaller compressor station, excluding land, is estimated at $1.5 - $3 million with approximate operating and maintenance costs of $50,000 - $150,000 annually.

Load Demand Curves

The culmination of the demand forecasting process is aggregating the information discussed in the previous sections into a forecast of future load requirements. As the previous sections illustrate, the customer forecast, design weather, core market usage per customer data, and large volume usage forecast are all key drivers in the development of the load demand curves.

The IRP customer forecast provides a total Company daily projection through Planning Year (PY) 2023 and includes a forecast for each of the five AOIs of the distribution system. Each forecast was developed under each of three different customer growth scenarios: low growth, base case, and high growth.

The development of a design weather curve – which reflects the coldest anticipated weather patterns across the Company's service area – provides a means to distribute the core market's heat sensitive portion of Intermountain's load on a daily basis. Applying design weather to the residential and small commercial usage per customer forecast creates core market usage per customer under design weather conditions. That combined with the applicable customer forecast yields a daily core market load projection through PY23 for the entire Company, as well as for each AOI. Similar to the above, normal weather scenario modeling was also completed.

As discussed in the Large Volume Customer Forecast Section, the forecast also incorporates the large volume CD from both a Company-wide perspective (interstate capacity) as well as from an AOI perspective (distribution capacity). When added to the core market figures, the result is a grand total daily forecast for both gas supply and capacity requirements including a break-out by AOI.

Peak day sendout under each of these customer growth scenarios was measured against the currently available capacity to project the magnitude, frequency and timing of potential delivery deficits, both from a Company perspective and an AOI perspective.

Once the demand forecasts were finished and the evaluation complete, the data was arranged in a fashion more conducive to IRP modeling. Specifically, the daily demand data for each individual forecast was sorted from high-to-low to create what is known as a Load Demand Curve (LDC). The LDC incorporates all the factors that will impact Intermountain's future loads. The LDC is the basic tool used to reflect demand in the IRP Optimization Model.

It is important to note that the Load Demand Curves represent existing resources and are intended to identify potential capacity constraints and to assist in the long term planning process. Plans to address any identified deficits will be discussed in the Planning Results Section of this report.

Customer Growth Summary Observations – Design Weather – All Scenarios

Idaho Falls Lateral

The Idaho Falls Lateral low growth scenario projects an increase in customers of 3,803 PY19 through PY23 (Jan 1, 2019 to Dec 31, 2023) which corresponds to an annualized growth rate of 1.49%. In the base case scenario customers are forecasted to increase by 7,772 (2.92% annualized growth rate), while the high growth scenario forecasts an increase of 10,938 customers (3.97% annualized growth rate).

Sun Valley Lateral

The Sun Valley Lateral low growth scenario (PY19 – PY23) projects an increase of 490 customers (0.89% annualized growth rate). In the base case scenario customers are projected to increase by 1,304 (2.26% annualized growth rate), while the high growth scenario shows an increase of 1,994 customers (3.34% annualized growth rate).

Canyon County Area

The low growth customer forecast (PY19 – PY23) for Canyon County Area reflects an increase of 11,395 customers (4.09% annualized growth rate). In the base case scenario customers are forecasted to increase by 14,854 (5.15% annualized growth rate), while the high growth scenario projects an increase of 17,188 customers (5.83% annualized growth rate).

State Street Lateral

The low growth customer forecast (PY19 – PY23) for the State Street Lateral reflects an increase of 4,318 customers (1.7% annualized growth rate). The base case scenario projects an increase of 7,065 customers (2.69% annualized growth rate), while the high growth scenario forecasts an increase of 10,273 customers (3.78% annualized growth rate).

Central Ada County

The low growth customer forecast (PY19 – PY23) for the Central Ada County reflects an increase of 4,397 customers (1.70% annualized growth rate). In the base case scenario customers are forecasted to increase by 6,622 (2.49% annualized growth rate), while the high growth scenario projects an increase of 8,654 customers (3.19% annualized growth rate).

Total Company

The Total Company (TC) low growth customer forecast (PY19 – PY23) projects an increase of 33,445 customers (1.91% annualized growth rate). The base case scenario forecasts an increase of 60,416 customers (3.30% annualized growth rate), while the high growth scenario projects an increase of 82,975 customers (4.37% annualized growth rate). Please note that the TC forecasts include the AOIs mentioned above as well as all other customers not located in a particular AOI.

Using the LDC analyses allows Intermountain to anticipate changes in future demand requirements and plan for the use of existing resources and the timely acquisition of additional resources.

Core Customer Distribution Sendout Summary – Design and Normal Weather – All Scenarios

Idaho Falls Lateral

IFL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,497,806	6,851,608	6,922,846	7,021,456	7,116,751
Base	6,510,490	6,955,973	7,125,180	7,326,306	7,528,354
High	6,520,563	7,038,871	7,285,625	7,568,233	7,855,001

IFL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,885,102	6,215,162	6,280,765	6,370,244	6,456,710
Base	5,896,701	6,309,812	6,464,327	6,646,800	6,830,116
High	5,905,923	6,384,991	6,609,880	6,866,278	7,126,459

Sun Valley Lateral

SVL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	2,134,862	2,180,583	2,190,120	2,208,738	2,225,805
Base	2,138,646	2,212,268	2,251,525	2,300,724	2,349,482
High	2,141,970	2,240,245	2,305,777	2,380,499	2,455,144

SVL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	1,893,932	1,934,153	1,943,094	1,959,620	1,974,756
Base	1,897,366	1,962,358	1,997,676	2,041,332	2,084,585
High	1,900,390	1,987,253	2,045,901	2,112,194	2,178,425

Canyon County Area

CCA Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,644,882	6,937,705	7,206,182	7,503,680	7,803,143
Base	6,654,154	7,022,665	7,375,106	7,762,669	8,158,671
High	6,659,942	7,075,569	7,479,998	7,931,253	8,395,219

CCA Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,278,733	5,510,136	5,723,042	5,959,382	6,197,250
Base	5,285,939	5,577,258	5,856,822	6,164,654	6,479,190
High	5,290,441	5,619,033	5,939,853	6,298,263	6,666,752

State Street Lateral

SSL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,753,345	6,892,311	6,977,131	7,093,800	7,212,472
Base	6,761,487	6,966,876	7,122,607	7,313,601	7,509,753
High	6,770,632	7,050,715	7,287,748	7,565,565	7,853,935

SSL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,265,382	5,374,278	5,439,666	5,530,627	5,623,132
Base	5,271,666	5,432,231	5,552,883	5,701,794	5,854,714
High	5,278,722	5,497,403	5,681,410	5,897,994	6,122,796

Central Ada County

CAC Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,746,456	6,868,791	6,955,257	7,073,623	7,193,992
Base	6,753,079	6,929,208	7,073,008	7,251,338	7,434,132
High	6,758,975	6,982,926	7,178,400	7,411,512	7,652,075

CAC Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,280,688	5,390,970	5,457,339	5,549,527	5,643,238
Base	5,285,795	5,437,905	5,548,906	5,687,765	5,830,103
High	5,290,343	5,479,616	5,630,846	5,812,362	5,999,681

Total Company

TC Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	46,572,743	47,636,823	48,393,973	49,290,102	50,132,353
Base	46,654,839	48,364,628	49,816,103	51,436,122	53,030,786
High	46,724,600	48,982,668	51,020,001	53,248,248	55,469,982

TC Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	39,209,059	40,107,255	40,738,558	41,492,753	42,201,795
Base	39,280,756	40,721,672	41,937,376	43,301,002	44,643,466
High	39,341,707	41,243,397	42,952,207	44,827,883	46,698,192

Projected Capacity Deficits – Design Weather – All Scenarios

Residential, commercial and industrial peak day load growth on Intermountain's system is forecast over the five-year period to grow at an average annual rate of 1.18% (low growth), 2.08% (base case) and 2.80% (high growth), highlighting the need for long-term planning. The next section illustrates the projected capacity deficits by AOI during the IRP planning horizon.

Idaho Falls Lateral LDC Study

When forecast peak day sendout on the Idaho Falls Lateral is matched against the existing peak day distribution capacity (88,400), peak day delivery deficit occurs under the base case scenario during PY23.

IFL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	9
High	0	0	0	148	2901

Sun Valley Lateral LDC Study

When forecasted peak day send out on the Sun Valley Lateral is matched against the existing peak day distribution capacity (19,878 Dth), peak day delivery deficits occur in PY21-PY23 under the base case scenario.

SVL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	221	631	1,021
High	0	0	599	1,220	1,840

Canyon County Area LDC Study

When forecasted peak day send out for the Canyon County Area is matched against the existing peak day distribution capacity (98,000 Dth), peak day delivery deficits occur in PY22-PY23 under the base case scenario.

CCA Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	1,944
Base	0	0	0	1,286	5,086
High	0	0	0	3,120	7,567

State Street Lateral LDC Study

When forecasted peak day send out for the State Street Lateral is matched against the existing peak day distribution capacity (73,000 Dth), a peak day delivery deficit occurs in PY23 under the base case scenario.

SSL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	70
High	0	0	0	555	3,313

Central Ada County LDC Study

When forecasted peak day send out for the Central Ada County is matched against the existing peak day distribution capacity (70,000 Dth), peak day delivery deficits occur in PY22-PY23 under the base case scenario.

CAC Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	658
Base	0	0	0	1,130	2,931
High	0	0	363	2,638	4,992

Total Company LDC Study

The Total Company perspective differs from the laterals in that it reflects the amount of gas that can be delivered to Intermountain via the various resources on the interstate system. Hence, total system deliveries should provide at least the net sum demand – or the total available distribution capacity where applicable - of all the laterals/AOIs on the distribution system. The following table shows that there are no peak day deficits based on existing resources.

TC Design Weather Peak Day Surplus (Deficit) (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	0
High	0	0	0	0	0

2019 IRP vs. 2017 IRP Common Year Comparisons

This section compares the Total Company and each AOI during the three common years of the 2019 and 2017 IRP filings. In some cases, the distribution transportation capacity is forecast to be lower in the 2019 IRP than it was in the 2017 IRP. This is the result of differences in, or fine tuning of, planned capacity upgrades.

Total Company Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	435,879	145,199	581,078
2020	450,704	146,407	597,111
2021	466,361	146,729	613,090

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	415,543	143,335	558,878
2020	426,723	145,335	572,058
2021	438,049	145,335	583,384

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE Over/(Under) 2017 IRP (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	20,336	1,864	22,200
2020	23,981	1,072	25,053
2021	28,312	1,394	29,706

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Total Company Peak Day Deliverability Comparison

2019 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2019	2020	2021
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	297,650	315,099	297,043
Total Peak Day Deliverability	543,162	560,611	542,555

2017 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2019	2020	2021
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	281,345	281,345	281,345
Total Peak Day Deliverability	526,857	526,857	526,857

2019 IRP PEAK DAY FIRM DELIVERY CAPABILITY Over/(Under) 2017 (Dth)	2019	2020	2021
Maximum Daily Storage Withdrawals:			
Nampa LNG	0	0	0
Plymouth LS	0	0	0
Jackson Prairie SGS	0	0	0
Total Storage	0	0	0
Maximum Deliverability (NWP)	16,305	33,754	15,698
Total Peak Day Deliverability	16,305	33,754	15,698

Idaho Falls Lateral Design Weather/Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	88,400	59,686	21,011	80,697
2020	88,400	61,352	21,311	82,663
2021	88,400	63,154	21,469	84,623

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	88,700	59,936	19,391	79,327
2020	88,700	61,819	19,391	81,210
2021	88,700	63,730	19,391	83,121

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE Over/(Under) 2017 IRP (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	(300)	(250)	1,620	1,370
2020	(300)	(467)	1,920	1,453
2021	(300)	(576)	2,078	1,502

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Sun Valley Lateral Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – SVL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	19,878	17,890	1,335	19,225
2020	19,878	18,287	1,375	19,662
2021	19,878	18,704	1,395	20,099

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	19,950	15,656	1,335	16,991
2020	19,950	15,875	1,335	17,210
2021	19,950	16,098	1,335	17,433

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	(72)	2,234	0	2,234
2020	(72)	2,412	40	2,452
2021	(72)	2,606	60	2,666

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Canyon County Area Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	98,000	63,269	25,395	88,664
2020	98,000	66,670	25,395	92,065
2021	98,000	70,339	25,218	95,557

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	93,000	60,921	26,320	87,241
2020	93,000	63,472	26,320	89,792
2021	93,000	65,997	26,320	92,317

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	5,000	2,348	(925)	1,423
2020	5,000	3,198	(925)	2,273
2021	5,000	4,342	(1,102)	3,240

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

State Street Lateral Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	73,000	64,634	1,220	65,854
2020	73,000	66,367	1,220	67,587
2021	73,000	68,146	1,220	69,366

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	67,000	62,308	2,630	64,938
2020	76,500	65,613	2,630	68,243
2021	76,500	67,269	2,630	69,899

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	6,000	2,326	(1,410)	916
2020	(3,500)	754	(1,410)	(656)
2021	(3,500)	877	(1,410)	(533)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Central Ada County Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	70,000	64,631	1,410	66,041
2020	70,000	66,261	1,410	67,671
2021	70,000	67,932	1,448	69,380

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	71,000	61,730	1,490	63,220
2020	71,000	62,832	1,490	64,322
2021	71,000	63,980	1,490	65,470

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2017	(1,000)	2,901	(80)	2,821
2018	(1,000)	3,429	(80)	3,349
2019	(1,000)	3,952	(42)	3,910

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Resource Optimization

Introduction

Intermountain's IRP utilizes an optimization model that selects resource amounts over a pre-determined planning horizon to meet forecasted loads by minimizing the present value of resource costs. The model evaluates and selects the least cost mix of supply and transportation resources utilizing a standard mathematical technique called linear programming. Essentially, the model integrates/coordinates all the individual functional components of the IRP such as demand, supply, demand side management, transport and supply into a least cost mix of resources that meet demands over the five-year IRP planning horizon, 2019 to 2023.

This section of the IRP report will first describe the functional components of the model, then the model structure and then its assumptions in general. At the end, model results will be discussed.

Functional Components of the Model

The optimization model has the following functional components:

- Demand Forecast by AOI
- Supply Resources, Storage and Supply, by Area
- Transportation Capacity Resources, Local Laterals and Major Pipelines, Between Areas
- Non-Traditional Resources such as Demand Side Management

Underlying these functional components is a model structure that has gas supply and demand by area (nodes) with gas transported by major pipelines and local distribution laterals (arcs) between supply and demand. This model mirrors, in general, how Intermountain's delivery system contractually and operationally functions. In any IRP model, there must be a balance between modeling in sufficient detail to capture all major economic impacts while, at the same time, simplifying the system so that the model operates efficiently and the results are understandable and auditable. Since Intermountain's model evaluates gas supply and capacity additions over a five year period, the model was designed so that only the major elements are recognized. This is in contrast to a dispatch model which needs to balance every detail precisely and so requires a level of detail that is fully representative of all daily system requirements. For this reason, a more simplified structure is utilized in the Company's IRP model.

Model Structure

In order to develop a basic understanding of how gas supply flows from the various receipt points to ultimate delivery to the Company's end-use customers, a graphical representation of IGC is helpful. Figure 42 is a medium detail map of the IGC system. Generally, gas flows from supply areas (nodes) such as Canada and the Rockies, and from storage in Washington state and Clay

Basin in the Rockies region (nodes), across major pipelines (arcs) to southern Idaho. In southern Idaho, the gas is transported to demand areas (nodes) by local distribution laterals. The model utilizes a simplified but generally correct structure of the Figure 42 map.

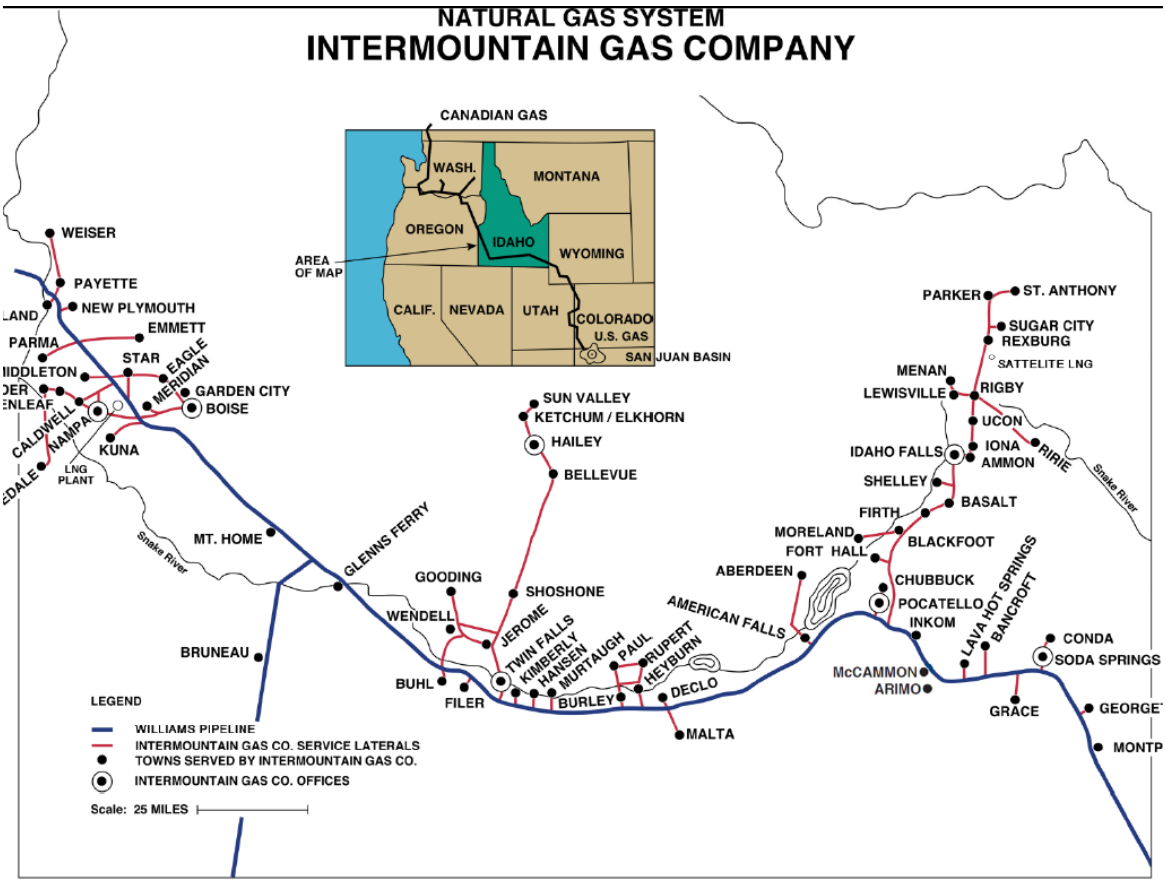


Figure 42: Natural Gas System Map – Intermountain Gas Company

Figure 43 presents the model of system flows by major pipelines and supply areas. Figure 43 shows four major supply receipt areas including Sumas, Stanfield, AECO and Rockies with ultimate delivery to IMG, southern Idaho.

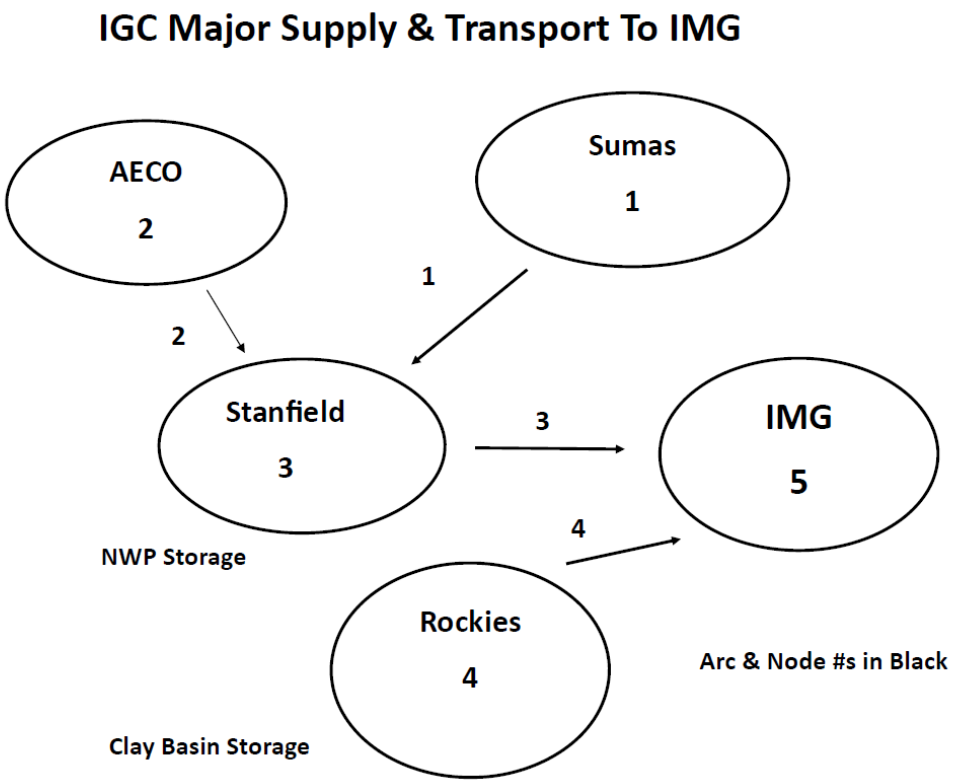


Figure 43: IGC Major Supply and Transport to IMG

Supplies from those supply receipt areas(nodes) are then delivered and aggregated at the IMG pool node where they are allocated to be delivered to the appropriate demand areas (nodes), or AOIs, by local distribution laterals (arcs) as depicted in Figure 44.

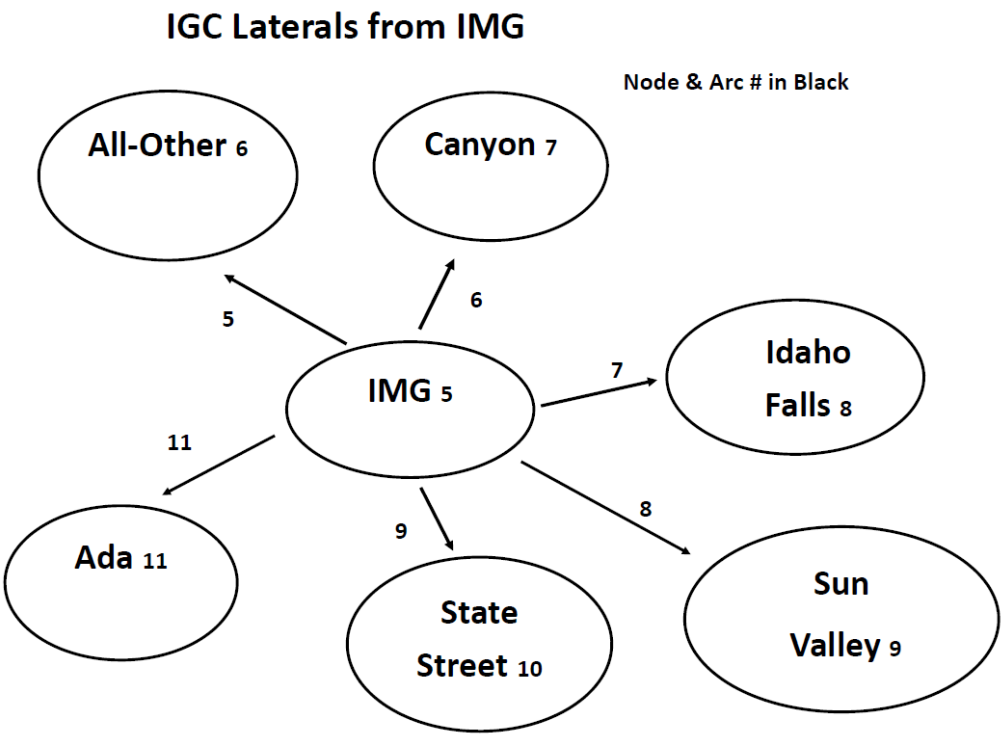


Figure 44: IGC Laterals from IMG

The final demand areas are the following as per Figure 44:

- Central Ada Area
- State Street Lateral
- Canyon County Region
- Idaho Falls Lateral
- Sun Valley Lateral
- All Other

The sum of all six areas is equal to system gas demand. A map of the AOIs is included at the end of the Executive Summary Section.

These map symbols were converted into a mathematical system of reference numbers so that a system of numbered arcs and nodes reflect physical locations on the map for the model. The resultant set of numbered arcs and nodes are shown on Table 14.

Table 14: Definition of Arcs & Nodes by Reference Number

Definition of Arcs & Nodes by Reference #s					
	Area/Node From		Area/Node To		
ARC #	Name	Area #	Name	Area #	Note
1	Sumas	1	Stanfield	3	Western Canada Gas
2	AECO	2	Stanfield	3	Alberta Gas
3	Stanfield	3	IMG	5	NWP path with NWP Storage
4	Rockies	4	IMG	5	Clay Basis & all south of IMG
5	IMG	5	All-Other	6	IGC Laterals from IMG
6	IMG	5	Canyon	7	IGC Laterals from IMG
7	IMG	5	Idaho Falls	8	IGC Laterals from IMG
8	IMG	5	Sun Valley	9	IGC Laterals from IMG
9	IMG	5	State St	10	IGC Laterals from IMG
10	IMG	5	Ada	11	IGC Laterals from IMG

Demand Area Forecasts

As previously discussed in the Load Demand Curves Section beginning on page 90, demands are forecasted using a unique LDC for each AOI. These LDCs are over a gas supply year for daily gas usage in MMBTU, nominally 365 days. To simplify the modeling, the LDC was aggregated into 12 homogenous periods with similar load characteristics, and then loads for each of those periods were averaged. Table 15 defines the periods used. The resultant demand curve represents load changes over the entire year but with a minimum of data points. Figure 45 depicts an example LDC aggregated into those homogenous groups. Figure 45 has ordered the demands from high to low for the full 365 days. Each aggregated level reflects one period modeled in the optimization model (i.e. the bold horizontal lines). The model recognizes the number of days in each period and computes the total flow per period.

Table 15: Periods for Optimization Modeling

Period	Days in Period	Cumul. Days in Period
1	1	1
2	1	2
3	2	4
4	5	9
5	8	17
6	14	31
7	31	62
8	28	90
9	61	151
10	61	212
11	61	273
12	92	365

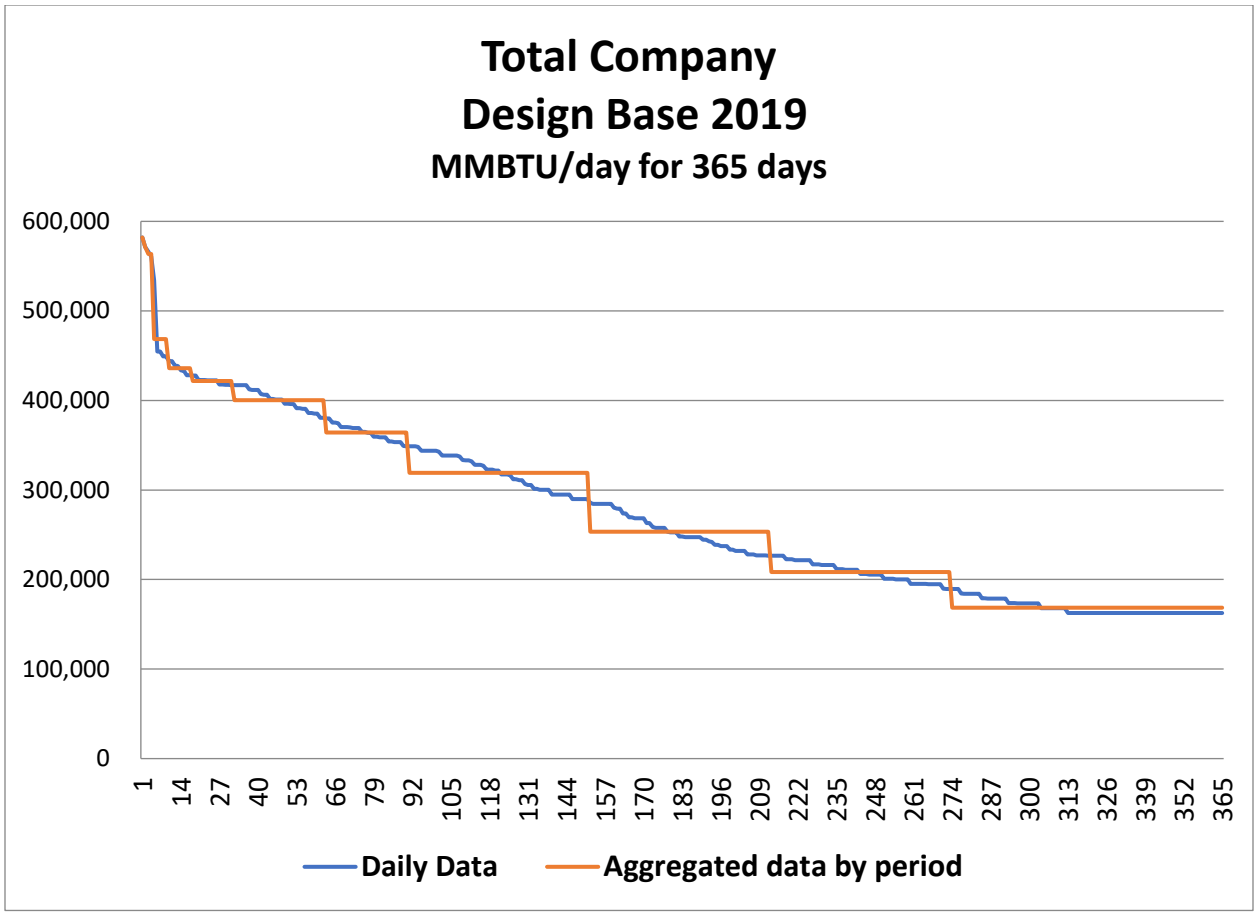


Figure 45: Total Company Design Base 2019

The model is also programmed to recognize that Intermountain must provide gas supply and both interstate and distribution transportation for its core market and LV-1 customers, but only firm distribution capacity for T-4 customers. T-3 is interruptible distribution capacity and as such is not included. Because Intermountain is contractually obligated to provide each day a certain level of firm transport capacity for its firm transporters, the industrial demand forecast for these customers is not load-shaped but reflects the aggregate firm industrial CD for each class by specific node for each period in the LDC.

Scenarios for the load demand curves are by weather and customer growth which are described elsewhere in this report. The weather scenarios are normal weather and design weather. Customer growth is separated into low growth, base case and high growth scenarios. This results in a total of six scenarios. The combination of the design weather and base case scenarios (Design Base) form the critical planning scenario for the report and will be reported as the main optimization results. Other scenarios are also available, but all others, except for the combined scenarios of design weather and high growth, would have sufficient resources as long as the Design Base does.

Supply Resources

Resource options for the model are of two types: supply resources and storage contracts, which, from a modeling standpoint, are utilized in a similar manner. All resources have beginning and ending years of availability, periods of availability, must take usage, period and annual flow capability and a peak day capability. Supply resources have price/cost information entered in the model over all points on the load demand curve for the study period. Additionally, information relating to storage resources includes injection period, injection rate, fuel losses and other storage related parameters.

Each resource must be sourced from a specific receipt point or supply area. One advantage of citygate supplies and certain storage withdrawals is that they do not utilize any of Intermountain's existing interstate capacity as the resource is either sited within a demand area node or are bundled with their own specific redelivery capacity. Supply resources from British Columbia are delivered into the Northwest system at Sumas while Rockies supplies are received from receipt pools known as North of Green River and South of Green River. Alberta supplies are delivered to Northwest's Stanfield interconnect utilizing available upstream capacity - the available quantity at Stanfield is the limiting factor regardless of capacity of any single upstream pipeline (AECO-Stanfield arc). Each supply resource utilizes transport arc(s) that reach the IMG node from its supply receipt node.

From a model perspective, the DSM resources are considered a subset of supply resources and fill demand needs on the applicable node by offsetting other supply resources when the cost of such is less than other available resources. These DSM resources have costs and resource capacity that were determined by a separate DSM analysis as detailed in the Core Market Energy Efficiency Section (starting on page 73).

Transport Resources

Transport resources are explicitly associated with arcs in the model which represent the way supplies flow from specific receipt areas to Intermountain's ultimate receipt pool identified as IMG, where all supplies are pooled for ultimate delivery into the Company's various demand nodes. Transport resources reflect contracts for interstate capacity, primarily on Northwest Pipeline, but also for the three separate pipelines that deliver gas supplies to Northwest's Stanfield interconnect from AECO. Because these pipelines operate in a serial fashion and have nearly identical flow capabilities, for modeling purposes, they are treated as one arc and are referred to as upstream capacity for gas originating at AECO and ending at Stanfield. There are also arcs reflecting each of the individual laterals representing the Areas of Interest. For example, supply resources to be delivered from Sumas to Idaho Falls, first must use the Sumas to Stanfield arc, the Stanfield to IMG arc and from there flow from IMG to the Idaho Falls arc. This ensures that the total supply deliveries cannot exceed total demand including laterals. Supplies such as the Rexburg LNG are already located on Intermountain's distribution system on a specific demand lateral and therefore do not require interstate pipeline transportation. The system representation recognizes Northwest's postage stamp pricing and capacity release.

Transport resources have a peak day capability and are assumed to be available year round unless otherwise noted. Transport resources can have different cost and capabilities assigned to them as well as different years of availability.

Model Operation

The selection of a least cost mix of resources, or resource optimization, is based on the cost, availability and capability of the available resources as compared to the projected loads at each of the nodes. The model chooses the mix of resources which meet the optimization goal of minimizing the present value cost of delivering gas supply to meet customer demand. The model recognizes contractual take commitments and all resources are evaluated for reasonableness prior to input. Both the fixed and variable costs of transport, storage and supply can be included. The model will exclude resources it deems too expensive compared to other available alternatives.

The model can treat fixed costs as sunk costs for certain resources already under contract. If a fixed cost or annual cost is entered for a resource, the model can include that cost for the resource in the selection process, if directed, which will influence its inclusion vis-à-vis other available resources. If certain resources are committed to and the associated fixed cost will be paid regardless of the level of usage, only the variable cost of that resource is considered during the selection process, but the fixed cost is included in the summary. However, any new resources, which would be additional to the resource mix, will be evaluated using both fixed and variable costs. For cost summary purposes, fixed costs were included, whether sunk or included in the least cost present value optimization, to approximate the expected revenue requirement for transport and supply.

The model operates in a PC environment. The various inputs are loaded via an Excel spreadsheet where they are loaded and utilized by PC linear programming software. The model is run by first launching the optimization software, opening the Excel model containing all the appropriate scenario of demand, supply, storage and capacity inputs (including all the correct prices) and calling up the correct constraint model set. The optimization software links the inputs to the constraint model, optimizes all resources to the period demands. Once the model computes the least cost resource mix, the results are organized by a set of macros that writes the output back into the same Excel model which simplifies, and minimizes the time, to audit and evaluate the model for reasonableness and accuracy.

Special Constraints

As stated earlier, the model minimizes cost while satisfying demand and operational constraints. Several constraints specific to Intermountain's system were modeled in the IRP model.

- Nampa LNG storage does not require redelivery transport capacity. Both SGS and LS storage are bundled with firm delivery capacity; transportation utilization of this capacity matches storage withdrawal from these facilities. SGS, LS and Clay Basin must be injected in the summer.

- All core market and LV-1 sales loads are completely bundled.

- T-4 customer transportation requirements utilize only Intermountain's distribution capacity. The T-4 firm CD is input as a no-cost supply delivered at IMG. T-3 is an interruptible distribution industrial rate and as such is not included.

- Traditional resources destined for a specific lateral node must be first transported to the IMG pool and then from IMG to the lateral node.

- Non-traditional resources such as mobile LNG that are designed to serve a specific lateral can only be employed when lateral capacity is otherwise fully utilized.

Model Inputs

The optimization model utilizes these three inputs which do not vary by scenario:

- Transport Resources
- Supply Resources by Year
- LDC Price Format for Supply Resources by Yearly Periods

These input tables are in Exhibit 7, Model Input Tables For All Scenarios. The one input table that does vary is the LDC table, which is the scenario referenced directly in this report. The Design Weather LDC is in Exhibit 8, Design Weather Load Demand Curve. Snapshots of Input and Output Tables where relevant are displayed below with descriptions and without formal numbering so as not to confuse other labeling.

Each resource, whether supply or transport, is given a resource number, name and an acronym and appropriate parameters as per Supply Resources by Year input tables in Exhibit 7. Table 14 and Figures 43 & 44 above have a summary of arcs and nodes referenced in these input tables. For example, in the Supply Resource Year 1, resource #1 is Shell Stanfield Winter, ShSta-W, see Figure 46. The resource is available for periods 1-9, at a max capacity of 10,000 MMBTU/day and a must use 1,510,000 MMBTU annually. It is delivered at Stanfield, node 3. Possible utilization rates can be set from 0% to 100%. Must take resources can be set with utilization rates set at a

min/max of 100% or set an annual rate as ShSta-W was. Period 9 in the example below allows this period to balance to the annual must take.

Supply Resource data input sheet by year: Min/Max Utilzation Rate
Intermountain Gas IRP Model
2019-2023 IGC IRP

Weather: Design
Growth: Base/Price: Base

	Year	1	2019		per day/	Assoc.	info		12 Number of periods of Utilization Rates (UR)									
50			Area		annual	Transport	Period		Min Max of UR by period from range set :use beg;end as guide									
#	Full name & Notes	Acronym	Delivered	#	mmbtu	Days	beg/end		1	2	3	4	5	6	7	8	9	10
1	Shell Stanfied Winter	ShSta-W	Stanfield	3	10,000	none	1	Min	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
1.5	firm winter	must take	100%		1,510,000	151.0	9	Max	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00

Figure 46: Supply Resource Data Input Sheet

Demand side management resources are labeled by the year they are providing supply across all programs. For example, DSM20 represents the amount of DSM supplied in 2020. Annual DSM study amounts were distributed to periods by residential seasonal usage patterns. Note, new DSM resources start in 2020.

The model selects the best cost portfolio based on least cost of present value resource costs over the planning horizon. However, it also has been designed to comply with operational and contractual constraints that exist in the real world (i.e. if the most inexpensive supply is located at Sumas, the model can only take as much as can be transported from that point; additionally, it will not take inexpensive spot gas until all constraints related to term gas or storage are fulfilled). In order for the results to provide a reasonable representation of actual operations, all existing resources that have committed must-take contracts are assigned as "must run" resources. The Company's minimal commitment for summer must-take supplies means that those supplies do not exceed demand. In the real world, having excess summer supplies results in selling those volumes into the market at the then prevailing prices whereas the model only identifies those volumes and related cost. Please note that this level of sales is small relative to total supply.

Another important assumption relates to the supply fill or balancing options. Supply fill resources provide intelligence as to where and how much of any deficit in any existing resource exists; the model treats them as economic commodities, meaning that availability is dynamic up to its maximum capability. The model can select available fill supply at any node, for any period and in any volume that it needs to help fill capacity constraints. To ensure that the model provides results that mirror reality, these supplies have been aggregated into peak, winter, summer and annual price periods. Each aggregated group has a different relative price with the peak price being the highest, and the summer price being the lowest. Additionally, since term pricing is normally based on the monthly spot index price, no attempt has been made to develop fixed pricing for fill resources but each such resource includes a reasonable market premium if applicable.

The storage injection table provides the amount of resources injected into the various storage facilities for which Intermountain retains direct control. Reflective of real-world cycling constraints, storage may only be withdrawn in the peak and/or winter periods and injections may only occur in summer periods.

In the LDC Price input table in Exhibit 7, prices for supply, except DSM, are based on the official IRP three hub price forecast (AECO, Sumas and Rockies). DSM pricing is based on an avoided cost study (starting on page 84) that has the hub prices forecast as an input.

All transport resources have specific arc numbers with to and from nodes specified as per the Transport Resource input table in Exhibit 7. Capability and pricing are included by resource. Transport resources that are existing pipeline and laterals including transport resources 5 through 8 that are tied to NWP storage resources are labeled as such. Proposed expansions of these are labeled as such. Transport fill resources represent expensive resources that provide a gap resource when there are not enough resources available. Three special alternative resources, 24, 25 and 28 (Canyon, Sun Valley and Ada) represent special resources that were developed as alternatives to preferred lateral expansions. This is in distinction to supply fill resources which represent balancing resources that can be acquired quickly.

Model Results

The optimization model results for the design weather, base price and base case scenario for the years 2019 through 2023 are presented and discussed below. The results of the model are summarized, for each scenario using the tables described below:

- Lateral Summary All Years
- Supply Summary All Years
- Annual Cost Summary All Years
- Supply Resource Usage Tables (Includes Flow and Capacity by Year and Period)
- Storage Injection Usage Tables (Includes Flow, Injection and Capacity by Year and Period)
- Transport Usage Tables (Includes Both Period and Annual Capacity Used by Year)

Exhibit 9, Design Base Output Tables shows the tables just described for the five periods of the Design Base case.

Model Output for Design Base Scenario

The following provides a description of the information presented by type of output tables in Exhibit 9 and the implication for the Design Base scenario.

The Lateral Summary Tables All Years provides a snapshot by year of whether a specific lateral to an AOI needs an expansion and whether that expansion is a preferred one as opposed to a fill or an alternative lateral resource. On the next page is the first year of the Lateral Summary Tables All Years, for the Design Base scenario, Figure 47.

The "Peak Day LDC" column is from the Design Base scenario and represents the load that must be met by lateral resources. The "Existing Lateral Capacity" column is the current existing capacity. The "Expansion Lateral Capacity" column represents the preferred planned expansion. The "Deficit of Existing" column represents the gap between demand and existing resources. If this column shows that additional capacity is needed, the model will select from a list of available enhancements outlined earlier in this report. If the "Fill/Alt. Lateral Capacity" column is zero, then there is sufficient planned expansion and existing capacity such that there is no resource gap. The table for year 1 displays that condition as do all the years for the Design Base scenario (Exhibit 9) so there is no resource gap. This is accomplished by planned expansions meeting new load.

Lateral Capacity Summary By Year
2019-2023 IGC IRP / Weather: Design / Growth: Base / Price: Base

Year	1	2019

MMBTU per day

Demand Node	Peak Day LDC	Existing Lateral Capacity	Expansion Lateral Capacity	Fill/Alt. Lateral Capacity	Existing + Expansion Capacity	Deficit of Existing
All-Other	260,597	296,029	0	0	296,029	0
Canyon	88,664	98,000	0	0	98,000	0
Idaho Falls (W LNG)	80,697	88,400	0	0	88,400	0
Sun Valley	19,225	19,878	0	0	19,878	0
State St	65,854	73,000	0	0	73,000	0
Ada	66,041	70,000	0	0	70,000	0
	581,078	645,307	0	0	645,307	0

Figure 47: Lateral Capacity Summary by Year

The Supply Usage Summary, Figure 48, is displayed below for the fifth year of the Design Base scenario study. All five years are provided in output Exhibit 9. It provides a general summary by major area as opposed to individual resources including DSM.

Year 5
IRP Model Summary Result, Supply in MMBTU per Day by Node Delivered by Period

Supply Area	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9	Period 10	Period 11	Period 12
Sumas	0	0	0	0	0	0	0	0	0	13,847	2,641	0
AECO	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	86,100	70,577
Stanfield	195,512	195,512	195,512	185,212	95,771	77,635	65,771	23,746	28,111	17,570	0	0
Rockies	110,114	101,082	95,116	70,820	110,114	110,114	110,114	110,114	71,551	40,000	40,000	36,466
IMG	220,476	217,630	217,630	217,630	165,686	165,686	165,686	165,686	165,686	162,733	157,630	157,630
All-Other	7,027	6,857	6,728	5,199	4,678	4,446	4,110	3,524	2,799	1,743	1,017	375
Canyon	0	0	0	0	0	0	0	0	0	0	0	0
Idaho Falls	0	0	0	0	0	0	0	0	0	0	0	0
Sun Valley	0	0	0	0	0	0	0	0	0	0	0	0
State St	0	0	0	0	0	0	0	0	0	0	0	0
Ada	0	0	0	0	0	0	0	0	0	0	0	0
Totals	645,330	633,281	627,186	591,061	488,449	470,081	457,881	415,270	380,348	348,093	287,388	265,048
LDC	645,330	633,281	627,186	591,061	488,449	470,081	457,881	415,270	380,348	308,093	241,443	199,030
O/U	0	0	0	0	0	0	0	*0*	*0*	*40,000*	*45,945*	*66,019*

Figure 48: Supply Usage Summary

The figure on the previous page provides supply by area by LDC period for a specified year. The LDC demands on the second to last line, LDC is the actual LDC demand by period for the year. The line above, Totals, is the actual gas supply and will match the LDC demand for periods 1-9. The supply will exceed the LDC demand for periods 10-12 representing injections needed for storage, the over/under line, "O/U". Sumas is utilized for supply of a portion of this injection gas consistent with planned operation. DSM will be in the All Other node as indicated above. Small LNG storage, such as Rexburg is treated as a lateral resource. For all years of the Design Base scenario, there are sufficient supply resources with DSM providing a portion of supply at avoided cost.

The Annual Cost Summary All Years table provides supply and transport costs by years that would very roughly approximate the fixed and variable cost of the revenue requirement. Under the Design Base scenario, costs are much higher than an actual year, so their level is not itself meaningful. The present value of these costs is also presented. The model will optimize on the least cost of the present value of the transport and supply costs designated in the model. The graph of the supply price hubs forecast is presented since it shows that there was a recent price spike in 2019 with a decline afterward which flattens out. The supply costs decline accordingly then rise. Cheaper fixed supply contracts end toward the end of the study period resulting in higher priced supply. Transport is fairly constant.

Supply Resource Usage output tables and Storage Injection Usage output tables contain detailed output data by resource by period by year. The input table discussion above provides a guide to the organization of the data. The information provided in the discussed Supply Summary output table provides a much broader overview of the supply situation.

The supply resources in the detailed output tables have the following output parameters:

- Utilization Rates by Period by Year
- Capacity Used by Period by Year
- Flow Used by Period by Year

The utilization rate is between 0.0 and 1.0 with 1.0 representing 100% utilization of the capacity of the resource. This is the easiest output parameter to check for a resource being used properly. The capacity used per period is simply capacity times the utilization rate. The flow is the volume as computed by days per period times the capability used.

Supply resources 1-3 represent must-take contracts that have total volumes that meet the contract amounts as demonstrated by the output related to volumes. The model does some minor adjustment between periods. Supply resources 4-6 represent balancing resources by major hub and as demonstrated by the output tables varies as needed to balance the system. AECO supply resources 7-11 act as the must run resources meeting transport constraints in the output tables. Storage resources 14-19 have proper summer injection to provide winter peak resources in the output tables. Resource 13 represents T-4 customers that purchase their own supply and transport where the model delivers it at IMG for free. Lastly, DSM is utilized as

expected in the output tables. The model chooses DSM as a resource when it is the least cost option based on its avoided cost.

Transport Usage Tables provide utilization rates and capacity used by transport resource by period by year. As discussed above, fill and alternative transport resources provide a gap analysis indication when the system is sized too small. Transport resources 19 to 28 represent these fill and alternative transport resources and none of these resources are utilized for any of the years for the Design Base scenario output tables. This indicates planned expansions are adequate to meet Design Base scenario peak needs.

Other Scenarios

Other scenarios with LDC input files and output tables are in Exhibit 10.

Summary

In summary the optimization model:

- Employs utility standard practice method to optimize the system via linear programming.
- Models DSM and storage.
- Handles storage withdrawal and injection across seasons.
- Provides a gap analysis on the need for lateral expansion not preferred.
- Provides a check on transport and supply capacity.
- Has convenient Excel spreadsheet input/output.

Planning Results

Throughout previous sections of the IRP it has been shown that projected growth throughout Intermountain's distribution system could possibly create capacity deficits in the future. Through the use of a gas optimization modeling system that incorporates total customer loads, existing pipe and system configurations along with current distribution system capacities, each potential deficit has been defined with respect to timing and magnitude. If any such deficit occurs, then an evaluation of system capacity enhancements is performed.

The five identified Areas of Interest that were analyzed under design conditions are: the State Street Lateral, Central Ada County, Canyon County, the Idaho Falls Lateral and the Sun Valley Lateral. Each of these areas are unique in their customer growth and pipeline characteristics, and the optimization of each requires different enhancement solutions.

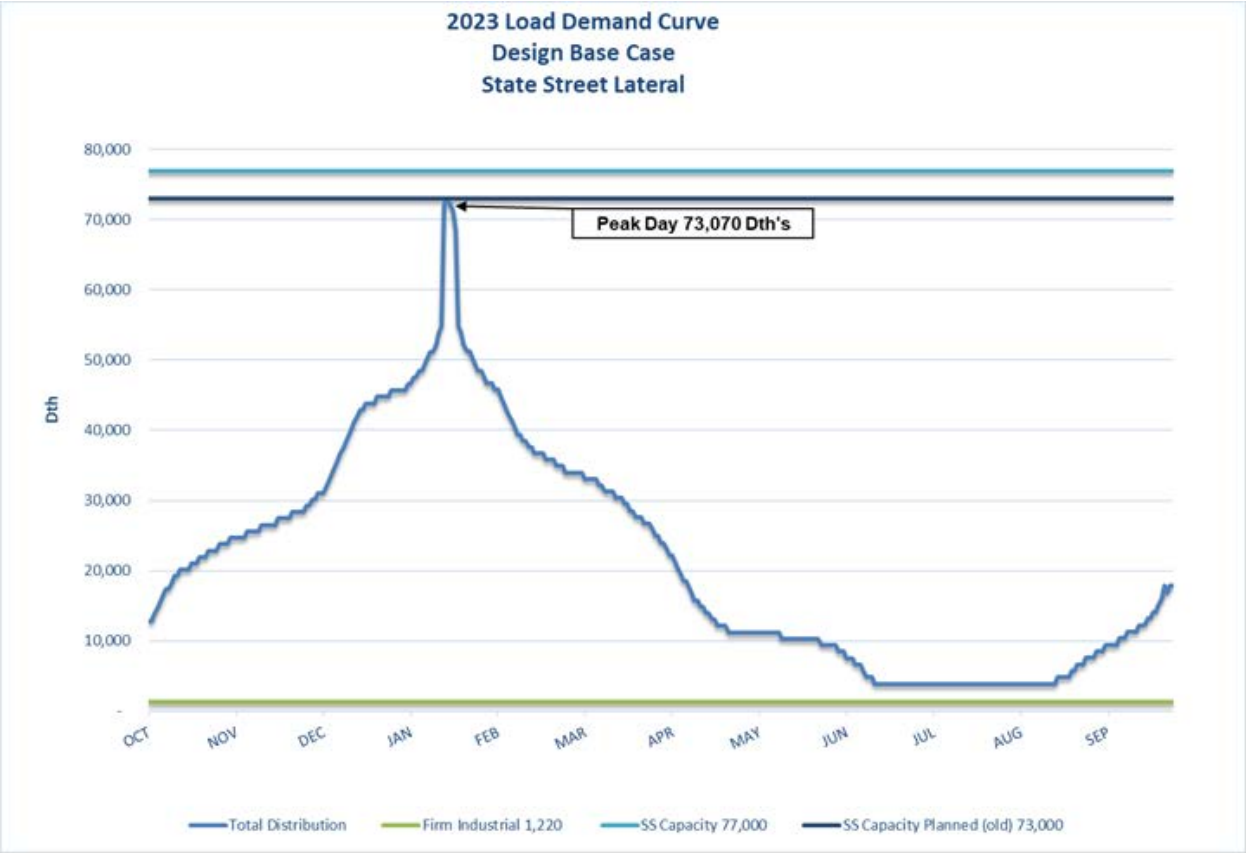
After discussing the enhancement solutions for the forecasted capacity deficits, this section will also compare the peak delivery deficits of the total Company as well as each AOI during the three common years of the 2019 and 2017 IRP filings.

State Street Lateral

The State Street Lateral is a 16-mile stretch of high pressure, large diameter main that begins in Caldwell and runs east along State Street serving the towns of Star, north Meridian, Eagle and into northern Boise. The lateral is fed directly from a gate station along with a back feed from another high-pressure pipeline from the south. Much of the pipeline is closely surrounded by residential and commercial structures that create a difficult situation for construction and/or large land acquisition, thus making a compressor station or LNG equipment less favorable. A complete review of the situation shows it is ideally suited to perform a pipeline retest that will establish a higher maximum allowable operating pressure and thus allow the Company to maximize the potential of its existing facilities before investing in new infrastructure. The retest can be performed in phases over multiple years which will provide increased capacity as actual growth is experienced, and phasing will minimize the length of pipe that must be taken out of service at one time.

The State Street retest enhancement is required within this IRP five-year outlook. The first phase of retesting will be completed in 2019. Phase one of the retest begins at the gate station and spans a 6.6-mile section downstream, ending near the intersection of State Street and Highway 16. With projected growth on the lateral, the second phase of retesting is required for the 2022 construction season and is currently planned for a 3-mile section extending east of Highway 16. Phase two of the State Street retest project will provide capacity beyond the IRP planning horizon.

The graph below shows no deficit with the proposed capacity under the base case scenario.



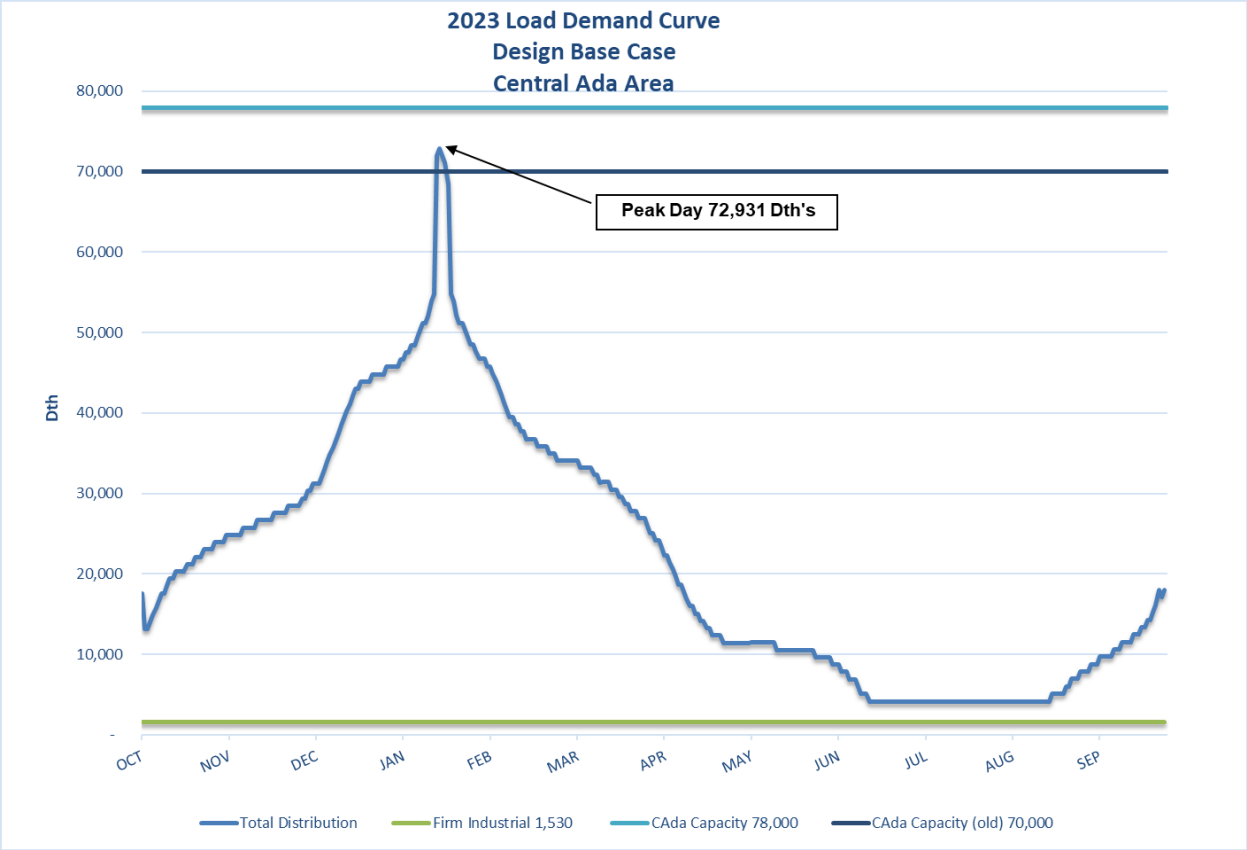
Central Ada County

Central Ada County is the newest AOI that consists of high pressure, intermediate pressure and distribution pressure systems in an area of Ada County that has historically experienced high levels of growth and development. The system currently has high pressure supplied from Chinden Boulevard on the north side of the defined area and high pressure supplied from Victory Road on the south side of the defined area. Initially the continued growth demands between these two separate systems taxed the Chinden high pressure pipeline and the branch lines supplied from Chinden. In 2016 an eight-inch pipeline was installed on Cloverdale Road that connected the Victory system to a branch of the Chinden system which alleviated the excess demand supplied from the Chinden pipeline. The connection between the two systems is an initial step in the long-term plan, and while the project successfully increased capacity in the area, the two systems are operating at different pressures and are currently disconnected through system valving.

With continued updates and monitoring of the Central Ada County AOI since the 2016 enhancement, continued growth has initiated the next planning step within the five-year outlook. Similar to State Street, the existing, large diameter pipeline on Victory Road has the potential for a pipeline retest that will increase its operating pressure and resulting flow capacity. This increase in operating pressure is designed to match the Chinden and Cloverdale operating pressure, and the retest is an initial step to create a consistent, connected system between the

pipelines. Phase one of the retest is currently scheduled for completion in 2021. The retest begins at the Meridian gate station and extends approximately 2.5 miles.

The graph below shows no deficit with the proposed capacity under the base case scenario.



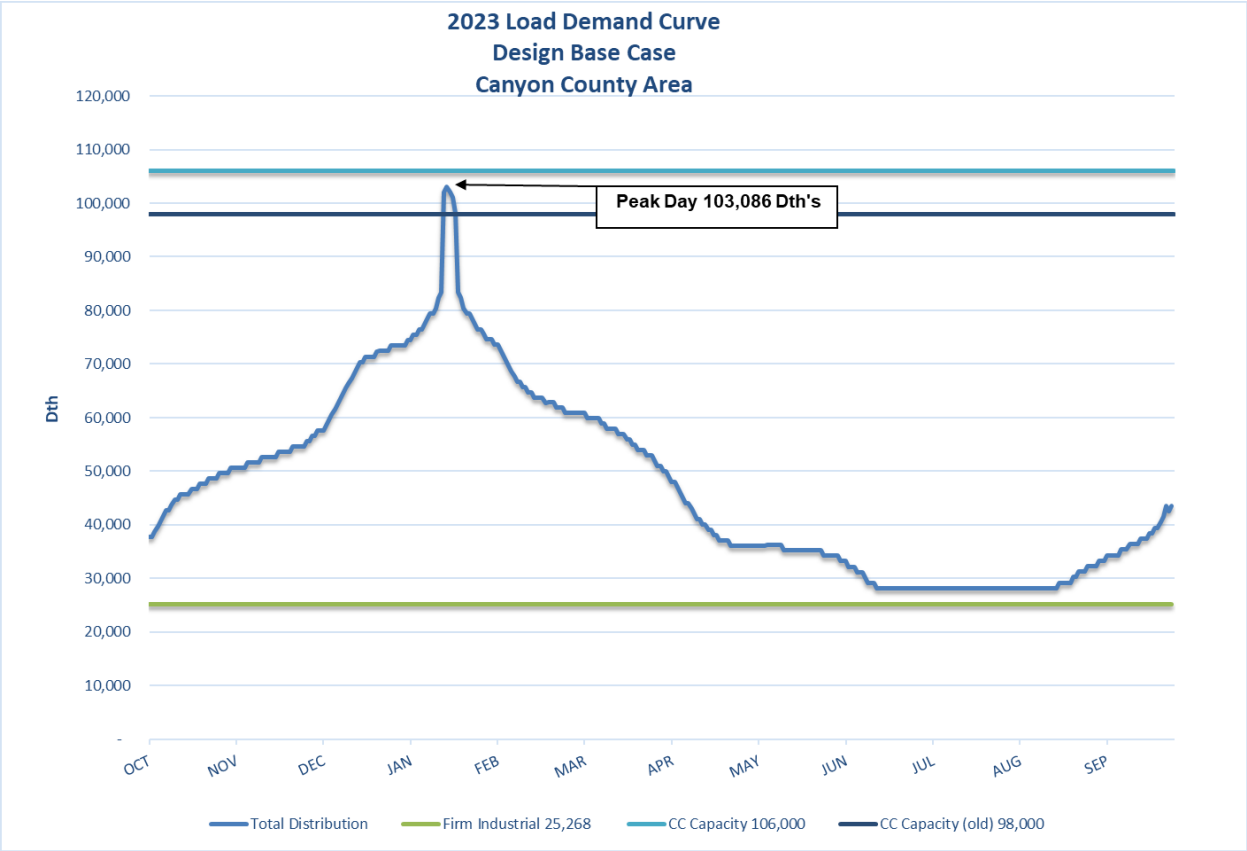
Canyon County

The Canyon County AOI consists of an interconnected system of high-pressure pipelines that serve communities from Star Road west to Highway 95. The system, originally serving Nampa and Caldwell, has continually extended west to additional towns and industrial customers. In 2013, the Canyon County system was connected to, and back-fed from, a new pipeline installed to the town of Parma. This Parma Lateral six-inch pipeline project provides a secondary feed to the Canyon County area. The next large system enhancement occurred in 2018 with the twelve-inch Ustick Caldwell pipeline project installed on the east side of Caldwell, which was required to remove pipeline flow restrictions through a bottleneck area.

For the outlook of this IRP, there are three enhancement projects required to meet projected growth demands throughout Canyon County. First is the 6-inch Orchard Avenue Extension project, which is planned for completion in 2020 and extends 4.5 miles into a significant growth area that is not currently supported by a nearby high-pressure pipeline. The Orchard Avenue Extension is location specific and not a direct benefit to the entire Canyon County AOI. Next is the second phase of the 12-inch Ustick Caldwell enhancement, extending the existing 2018

pipeline an additional 2 miles to the east. The 12-inch Ustick Caldwell project has a planned completion date of 2021 and is a benefit for the entire high-pressure system in Canyon County, continuing to eliminate bottlenecks in the overall system. Last is the 8-inch Happy Valley enhancement which extends high pressure pipeline 2 miles further into south Nampa. The 8-inch Happy Valley enhancement is currently planned for construction in 2022. This project is, again, designed as a location specific enhancement to accommodate specific growth and not directly related to the overall Canyon County AOI capacity.

The graph below shows no deficit with the proposed capacity under the base case scenario.



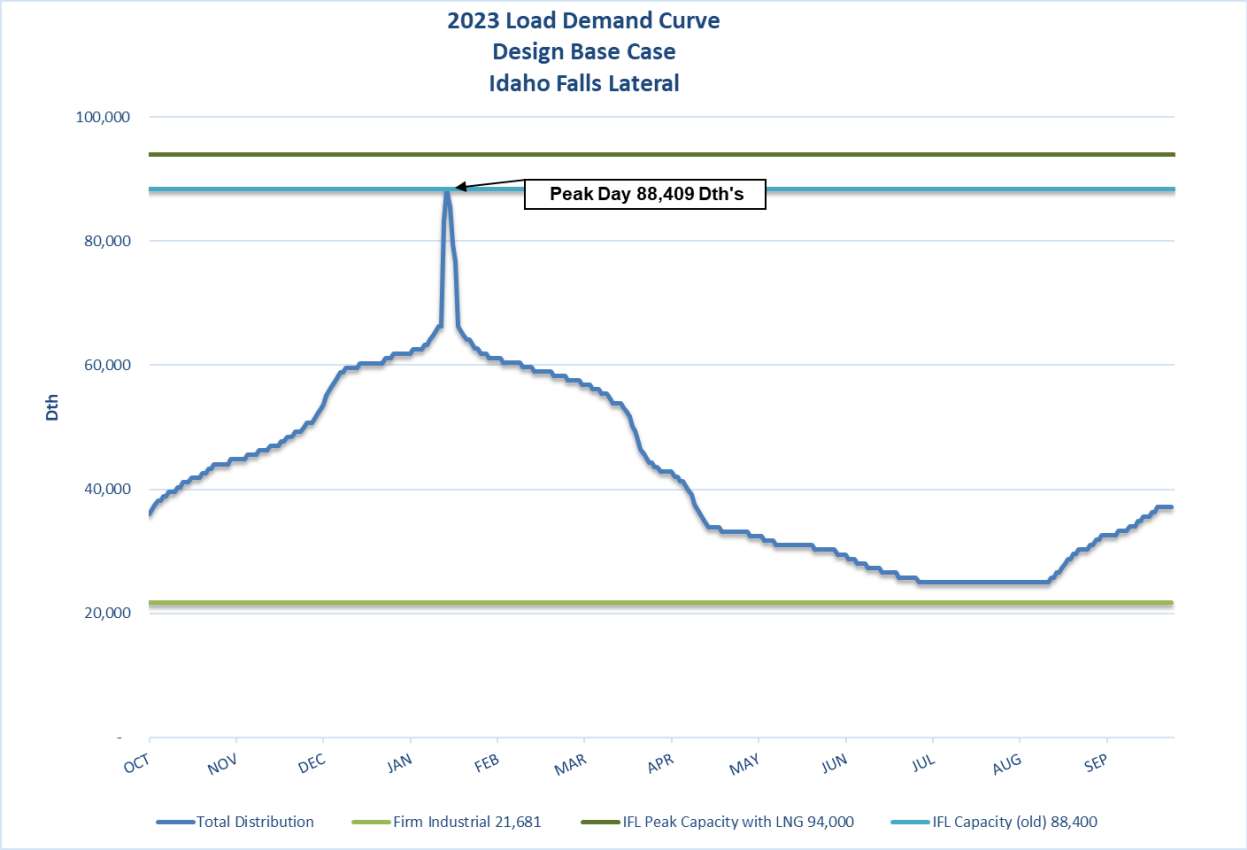
Idaho Falls Lateral

The Idaho Falls Lateral began as a 52-mile, ten-inch pipeline that originated just south of Pocatello and ended at the city of Idaho Falls. The IFL was later expanded farther to the north extending an additional 52 miles with 8-inch pipe to serve the growing towns of Rigby, Lewisville, Rexburg, Sugar City and Saint Anthony. As demand has continually increased along the IFL, Intermountain has been completing capacity enhancements for the past 25 years; including, compression (now retired), a satellite LNG facility, 40 miles of 12-inch pipeline loop, and 34.5 miles of 16-inch pipeline loop.

In 2012, Intermountain completed the addition of Phase V, a project that extended 15.5 miles of 16-inch high pressure pipeline to the north of Idaho Falls and increased the year-round capacity

available on the lateral. With the addition of Phase V, and, utilizing the peak shaving benefits of the Rexburg LNG Facility, Intermountain has the capacity to serve the IFL for the next five years. Included as an IFL capacity enhancement within this IRP period is the addition of a second LNG storage tank at the Rexburg LNG Facility in 2022. The second tank will increase total available storage at the facility, which is desired as potential vaporization flow requirements increase out of the facility.

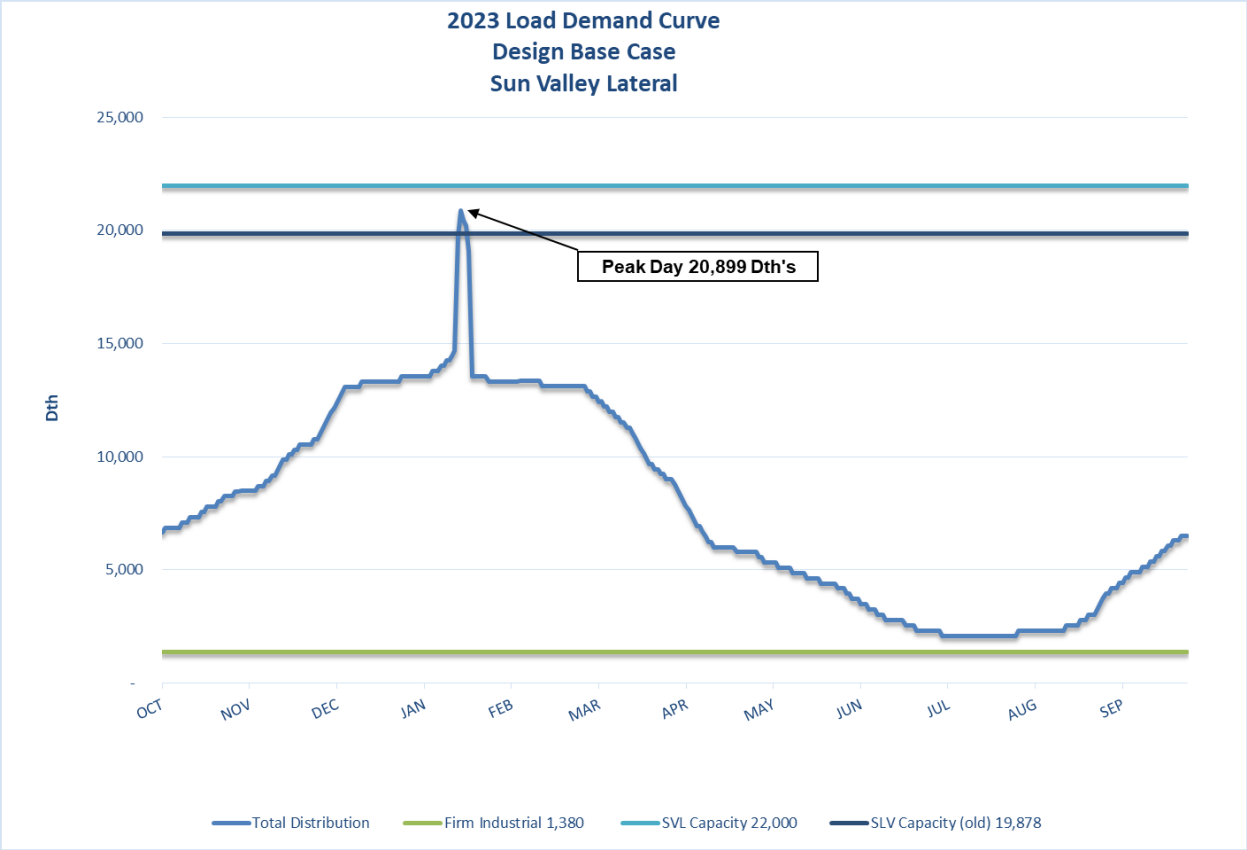
The graph below shows no deficit with the proposed capacity under the base case scenario.



Sun Valley Lateral

The Sun Valley Lateral is a 68-mile long, 8-inch high pressure pipeline that has almost its entire demand at the far end of the lateral away from the source of gas. Obtaining land in close proximity to this customer load center is either expensive or simply unobtainable. In addition, long sections of the pipeline are installed in rock that impose construction obstacles. Throughout the years Intermountain has uprated and upgraded this existing lateral, and most recently installed the Jerome Compressor Station towards the south end of the lateral in order to maintain capacity and increase flow toward the north end of the system. With continued demand growth, a second compressor station has been selected for enhancement of the SVL further downstream from the existing Jerome Compressor. This second station is scheduled for completion in 2021 and will increase capacity beyond the remaining five-year growth outlook of this IRP.

The graph below shows no deficit with the proposed capacity under the base case scenario.



2019 IRP vs. 2017 IRP Common Year Comparisons

This section compares any firm delivery deficits for Total Company and each AOI during the three common years of the 2019 and 2017 IRP filings.

Total Company Peak Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2017 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2019 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Idaho Falls Lateral Peak Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Sun Valley Lateral Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Canyon County Area Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

State Street Lateral Firm Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Central Ada County Firm Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE Over/(Under) 2017 (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Non-Utility LNG Forecast

Introduction

Since 1974, Intermountain has operated its Nampa Liquid Natural Gas (LNG) facility as a winter peaking supply source. The plant is designed to liquefy natural gas into LNG, store it in an onsite tank and vaporize it for injection into the Company's distribution system. The plant design includes a 50,000 gallon per day liquefaction train, a seven million-gallon storage tank and two water-bath vaporization units. The Nampa facility is utilized as the top of the Company's supply stack, or in other words, the last supply source that is used in the event of very cold weather or extraordinary system constraints.

In 2012 Intermountain began an efficiency review that focused on how it might better utilize its Nampa asset. Utilizing the then current IRP forecast, Intermountain determined how many gallons were projected to be withdrawn each winter season. That analysis showed that even under design weather assumptions, an excess of LNG supply would likely be available in each winter season.

Concurrent with the efficiency study, Intermountain began a study to determine the status of the regional LNG supply market relative to providing LNG to the Company's remote LNG facility near Rexburg, Idaho. Intermountain contacted several producing and marketing entities in the area who were then engaged in the non-utility LNG business to gauge future supply as well as the potential to enter the market as a supplier of LNG. It was discovered that due to already existing firm commitment during the heating season, it would be difficult to guarantee that an LNG supply would be available to Intermountain's Rexburg facility during the peak winter months.

History

LNG is a clean burning fuel that has the advantages of easy storage and transport under the right conditions. The two biggest markets for regional LNG are trucking fleets and remote-site heat and/or power applications. Though in relative infancy in the United States – particularly in the Pacific Northwest – LNG from a global perspective has a longer track record and continues to be in high demand in energy import areas like Asia.

As a direct result of the LNG supply study, Intermountain received an emergency supply request in late January 2013 to supply LNG to a small LNG-based distribution utility located in southwestern Wyoming that temporarily had lost its supply of LNG. The Idaho Public Utilities Commission (Commission) immediately granted emergency authority for Intermountain to supply the needed LNG pursuant to Case No. INT-G-13-01. Based on the efficiency review, the market study and the experience gained from supplying the emergency LNG, the Company filed Case No. INT-G-13-02 to request on-going authority from the Commission to sell "excess" LNG to non-utility customers.

Method of Forecasting

Intermountain utilized the results of the supply study (see Load Demand Curves starting on page 90) in this IRP to determine how much Nampa LNG would be needed for the core market during each year under the design weather/high growth scenario. To determine the annual amount of "excess" LNG, Intermountain adds to that annual core market withdrawal volume 1.2 million gallons of annual boiloff gas (which naturally occurs with the warming of LNG), 300,000 gallons to maintain operational and training requirements at the Nampa and Rexburg LNG facilities, and 500,000 gallons of "permanent" inventory to ensure that all LNG does not boiloff. After summing those potential needs for each year, the remaining capacity is assumed to be available for non-utility LNG sales customers. The table below shows the annual amount of Nampa LNG assumed to be available for non-utility sales over the IRP. For planning purposes, Intermountain will not allow the tank inventory level to drop below the Net Utility Requirements shown below at any time during December – February of any year since this is the peak demand season for the Company's distribution system. Further, should the need arise, all volumes are always available to serve the core market. It should be noted that the amount shown as "Available for Non-utility Sales" is a point-in-time figure.

Table 16: Nampa LNG Inventory Available for Non-Utility Sales

Nampa LNG Inventory Available for Non-Utility Sales					
Gallons	2019	2020	2021	2022	2023
Projected Withdrawal (High Growth)	0	0	21,417	101,928	195,055
Maximum Day Withdrawal	0	0	17,216	40,498	64,534
Annual Boil-off	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Permanent Inventory	500,000	500,000	500,000	500,000	500,000
Nampa & Rexburg Requirements	300,000	300,000	300,000	300,000	300,000
Net Utility Requirement	2,000,000	2,000,000	2,021,417	2,101,928	2,195,055
Available for Non-utility Sales	5,000,000	5,000,000	4,978,583	4,898,072	4,804,945

Benefits to Customers

Intermountain's customers benefit from Intermountain's LNG sales activities in several different ways. First, Intermountain continues to defer 2.5¢ per gallon sold into a capital account and utilizes that balance as it identifies capital costs that were accelerated due to increased use of the Nampa LNG facility. That procedure directly reduces both rate base and depreciation expense. Intermountain also continues to pass back to customers in its annual Purchased Gas Adjustment filing (PGA) a credit of 2.5¢ per gallon sold as an offset to increased operating and maintenance costs as a result of non-utility sales. Finally, Intermountain's customers also benefit

from the current 50/50 margin sharing mechanism which offsets gas purchase costs in the Company's annual PGA.

Since April 2013, Intermountain has sold nearly 20 million gallons of non-utility LNG. These sales have provided nearly $500,000 to offset increased capital costs. Additionally, the Company has passed back through its PGA approximately $500,000 to offset increased O&M costs as well as over $2.5 million from the margin sharing mechanism. The PGA passback has reduced Intermountain's gas costs every year since October 2013.

Another benefit comes from the fact that the Company has been selling much of its LNG to markets which utilize it in Idaho. Much of the market relates to trucks that formerly burned diesel as a fuel. LNG sales have increased economic growth in the state and have also provided cleaner air benefits. The markets Intermountain sells LNG to have expressed appreciation for a local, reliable, competitively priced fuel. In fact, they have gone so far as to suggest that if the Nampa facility was no longer able to supply non-utility LNG, it would leave a hole in the fuel market that would be difficult, if not impossible, to fill. Further, many of the truck drivers have expressed a preference to load at Nampa as the design and operations allow for more convenient and quicker trailer fills.

On-Going Challenges

Since one of the biggest potential target markets for Intermountain is "big rig" diesel fuel replacement, the relatively low retail diesel prices over the past several years has stunted the growth in the LNG trucking market. Low diesel prices tighten the cost differential between diesel and LNG and consequently the Company has had little ability to increase sales prices.

A further challenge has been the lack of available large displacement LNG engines. Because of the frequency and magnitude of roadway inclines, the mountain west trucking industry prefers to rely on 15-liter engines. However, manufacturers do not produce a 15-liter LNG engine, resulting in a challenge to utilize natural gas-powered engines to haul the heaviest loads. Thus, lower diesel prices combined with the lack of a 15-liter, LNG-powered engine has hampered growth in LNG sales demand. These challenges have limited revenue growth in Intermountain's non-utility LNG sales.

The good news is that continuing efforts to work with existing LNG markets while also marketing to new entities has resulted in Intermountain growing its sales every year since 2013. Further, Intermountain continues to improve its management of LNG inventory cost which has helped to support average sales margins.

Safeguards

As described above, Intermountain takes steps to ensure that it maintains enough LNG in the tank to provide for all projected customer withdrawal needs. This insulates the core market from

the risk of having no LNG should the need for needle peak withdrawals arise. Intermountain has also committed to the Commission that all volumes in the tank, regardless of the intended market, would always be available to serve the core market should the need arise. Additionally, while the Company shares LNG margins with its customers through the PGA, it also insulates its end-use customers from any risk of loss due to non-utility sales.

Future

Intermountain continues to see growth in non-utility LNG sales and may even reach a point where annual liquefaction levels are maximized. As the market continues to look for ways to satisfy ever more stringent emissions standards, it is believed that LNG will generate more interest. Looking to the future, most forecasts predict a continuation of low oil and natural gas prices leading the Company to expect somewhat flat sales margins but steady growth in LNG sales.

One advantage the Company has is the ability to store large amounts of LNG which would last for an extended period of time for vaporization purposes. Because of its storage capability, some markets look to Nampa as a backstop supplier when other facilities might experience outages or planned downtime. Should the non-utility sales market continue to show strong growth, the Company would likely not need more storage capacity, but could address the need for more day-to-day sales volumes by adding to or upgrading its liquefaction train in order to increase the daily production of LNG.

The biggest disadvantage of the Nampa plant relates to the cost of liquefaction. Stand-alone commercial LNG production facilities do not need large storage tanks, vaporizers or other equipment designed to support peak shaving withdrawals and can therefore operate at a lower cost. In addition, newer facilities utilize more recent technology that can simply liquefy more efficiently than older facilities. A potential risk to Intermountain's LNG sales would be the construction of new commercial LNG facilities in the region that would have lower operating costs which could result in the loss of customers currently served by the Nampa facility or lower sales margins.

Recommendation

Challenges relating to growth in sales volumes and a market facing flat margins growth remain. A longer-term increase in diesel prices would provide more opportunity to grow both non-utility LNG sales and margins. Intermountain's Nampa LNG facility is located in an area without direct competitors and the Company continues to build brand loyalty. Based on the benefits to Intermountain and its utility customers, the lack of risk to its customers and the ability to make more efficient use of the Nampa LNG assets, Intermountain recommends that the Commission continue to allow Intermountain to sell excess LNG to non-utility customers.

Infrastructure Replacement

Intermountain Gas Company is committed to providing safe and reliable natural gas service to its customers. As part of this commitment, Intermountain proactively monitors its pipeline system utilizing risk management tools and engineering analysis. Additionally, the Company adheres to federal, state and local requirements to replace or improve pipelines and infrastructure as required. Infrastructure that is identified as a potential risk is reviewed and prioritized for replacement or risk mitigation.

As part of the IRP process, Intermountain will address two significant infrastructure replacement projects scheduled to occur within the IRP outlook. These replacement projects are not growth driven.

Rexburg Snake River Crossing

The Rexburg Snake River crossing is an eight-inch steel transmission pipeline installed under the Snake River southwest of Rexburg, ID which has been identified as an infrastructure replacement project, tentatively scheduled for planning year 2021. The pipeline was identified for replacement due to risks related to the Snake River and surrounding flood plain. The location of the pipeline under the Snake River and perpendicular to the river along its east bank leave the pipeline susceptible to loss of adequate cover should the river's rate of flow increase to the point of spilling over the existing bank and/or scouring the existing river bottom.

The Rexburg Snake River crossing has been monitored and has required occasional attention. The riverbank has been rebuilt and reinforced by Intermountain to prevent undermining of the bank and reduce the potential to flood, and the Company has installed engineered scour protection measures over the top of the pipeline to prevent cover loss within the river. These efforts have been successful to date; although, due to the ongoing monitor and mitigation efforts, along with the ever-present risks associated with this scenario, the Company plans to replace the existing pipeline.

Intermountain's selected replacement method for this existing river crossing is to utilize horizontal directional drilling technology to install a new pipeline much further below the river bottom and surrounding flood area. Horizontal directional drilling will allow the pipeline to be installed much deeper in the ground than conventional installation practices and will avoid any disturbance to the Snake River and the sensitive land surrounding the river. The significant increase in pipeline depth will mitigate the existing risk.

Aldyl-A Pipe Replacement

Intermountain has created an Integrity Management Program to proactively identify, analyze and monitor any risk related to the pipeline system, and to create programs that will reduce or remove those risks. In order to identify risks on the system, the Company utilizes a risk model to manage and assess the risk of infrastructure based on age, material, operating pressure and

damage history, as well as other considerations. The model is then used to prioritize mitigation efforts, and infrastructure replacement projects are created as a result. Aldyl-A pipe replacement was identified as a priority from the risk model and has become a substantial, ongoing project.

Aldyl-A is a polyethylene material created by DuPont and used in the manufacturing of pipe and fittings. Aldyl-A pipe manufactured prior to 1984 is now known in the gas industry as being susceptible to loss of flexibility which can allow cracking under certain circumstances. Since 2013, Intermountain has actively replaced Aldyl-A plastic pipe within the distribution system and continues to replace approximately five miles of pipeline each year; prioritized by risk metrics that are renewed annually. The Aldyl-A replacement plan will continue through the duration of the IRP.

Glossary

Agent (Marketer)
A legal representative of buyers, sellers or shippers of natural gas in negotiation or operations of contractual agreements.

All Other Customers Segment (All Other)
All other segments of the Company's distribution system serving core market customers in Ada County not included in the State Street Lateral or Central Ada County, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties; an Area of Interest for Intermountain.

Area of Interest (AOI)
Distinct segments within Intermountain's current distribution system.

British Thermal Unit (BTU)
The amount of heat that is necessary to raise the temperature of one pound of water by 1 degree Fahrenheit

Bundled Service
Gas sales service and transportation service packaged together in a single transaction in which the utility, on behalf of the customer, buys gas from producers and then transports and delivers it to the customer.

Canyon County Area (CCA)
A distinct segment of Intermountain's distribution system which serves core market customers in Canyon County; an Area of Interest for Intermountain.

Central Ada County (CAC)
Multiple high-pressure pipeline systems which serve core market customers in Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west; an Area of Interest for Intermountain.

Citygate
The points of delivery between the interstate pipelines providing service to the utility or the location(s) at which custody of gas passes from the pipeline to the utility.

Commercial
A customer that is neither a residential nor a contract/large volume customer whose requirements for natural gas service do not exceed 2,000 therms per day. These customers are typically commercial businesses or small manufacturing facilities.

Contract Demand (CD)
The maximum peak day amount of distribution capacity that Intermountain guarantees to reserve for a firm customer each day. The amount is specified in the customer contract. Also see MDFQ.

Core Market
All residential and commercial customers of Intermountain Gas Company. Includes all customers receiving service under the RS and GS tariffs.

Customer Management Module (CMM)
A software product, provided by DNV GL as part of their Synergi Gas product line, to analyze natural gas usage data and predict usage patterns on an individual customer level.

Delivery (Receipt Point)
Designated points where natural gas is transferred from one party to another. Receipt points are those locations where a local distribution company delivers, and an interstate pipeline receives, gas supplies for re-delivery to the local distribution company's city gates.

Design Year
An estimate of the highest level of annual customer demand that may occur, incorporating extreme cold or peak weather events; a measure used for planning capacity requirements.

Design Weather
Heating degree days that represent the coldest temperatures that may occur in the IGC service territory.

Direct Use
The use of natural gas at the point of final heating energy use, such as natural gas space heating, water heating, cooking, and other heating uses, as opposed to burning natural gas in a power plant to generate electricity to be used at the point(s) of use to for site space heat, water heat, cooking heat and other heat applications. Direct use is a much more efficient use of natural gas.

Demand Side Management (DSM)
Programs implemented by the Company and utilized by its customers to influence the amount and timing of natural gas consumption.

Electronic Bulletin Board (EBB)
A generic name for the system of electronic posting of pipeline transmission information as mandated by FERC.

FERC - Federal Energy Regulatory Commission
The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act. Successor to the Federal Power Commission, the FERC is considered an independent regulatory agency responsible primarily to Congress, but it is housed in the Department of Energy.

Firm Customer
A customer receiving service under rate schedules or contracts designed to provide the customer's gas supply and distribution needs on a continuous basis, even on a peak day.

Firm Service
A service offered to customers under schedules or contracts which anticipate no interruptions.

Fixed Physical
A fixed forward (also known as a fixed price physical contract) is an agreement between two parties to buy or sell a specified amount of natural gas at a certain future time, at a specific price, which is agreed upon at the time the deal is executed. It operates much like the price swap without the margin call risk.

Formation
A formation refers to either a certain layer of the earth's crust, or a certain area of a layer. It often refers to the area of rock where a petroleum or other hydrocarbon reservoir is located. Other related terms are basin or play.

Gas Transmission Northwest (GTN)
A U.S. pipeline which begins at the U.S.-Canadian border near Kingsgate, British Columbia and interconnects with Williams Northwest Pipeline at the Stanfield receipt point in Oregon.

Heating Degree Day (HDD)
An industry-wide standard, measuring how cold the weather is based on the extent to which the daily mean temperature falls below a reference temperature base, which for IGC, is 65 degrees Fahrenheit.

Horizontal Directional Drilling
Heralded as causing the greatest change in the industry since the invention of the rotary bit, horizontal drilling utilizes special equipment that allows well drillers to extend horizontal shafts from one vertical shaft into areas that could not otherwise be reached. This technique is especially useful in offshore drilling, where one platform may service many horizontal shafts, thus increasing efficiency. Horizontal wells can be extended from as short as 20-40ft from vertical to as long as 1,000-4,500ft from the vertical radius.

Idaho Falls Lateral (IFL)
A distinct segment of Intermountain's distribution system which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties; an Area of Interest for Intermountain.

Industrial Customer
For purposes of categorizing large volume customers, any customer utilizing natural gas for vegetable, feedstock or chemical production, equipment fabrication and/or manufacturing or heating load for production purposes.

Institutional Customer
For purposes of categorizing large volume customers, this would include business such as hospitals, schools, and other weather sensitive customers.

Interruptible Customer
A customer receiving service under rate schedules or contracts which permit interruption of service on short notice due to insufficient gas supply or capacity.

Interruptible Service
Lower-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the higher priority claim of firm service customers and other higher priority users. Service is available at any time of the year if distribution capacity and/or pressure is sufficient.

Large Volume Customer
Any customer receiving service under one of the Company's large volume tariffs including LV-1, T-3, and T-4. Such service requires the customer to sign a minimum one-year contract and use at least 200,000 therms per contract year.

Liquefied Natural Gas (LNG)
Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. In volume, it occupies one-six-hundredth of that of the vapor at standard conditions.

Load Demand Curve (LDC)
A forecast of daily gas demand using design or normal temperatures, and predetermined usage per customer.

Local Distribution Company
A retail gas distribution company, utility, that delivers retail natural gas to end users.

Lost and Unaccounted for Natural Gas (LAUF)
The difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers.

Maximum Daily Firm Quantity (MDFQ)
The contractual amount that Intermountain guarantees to deliver to the customer each day. Also see Contract Demand.

Methane
Methane is commonly known as natural gas (or CH_4) and is the most common of the hydrocarbon gases. It is colorless and naturally odorless and burns efficiently without many by products. Natural gas only has an odor when it enters a customer's home because the local distributor adds it as a safety measure.

Normal Weather
Normal weather is comprised of HDD's that represent the average mean temperature for each day of the year. Intermountain's Normal Weather is a 30-year rolling average of NOAA's daily mean temperature.

Northwest Pipeline (Williams Northwest Pipeline, Northwest, NWP)
A 3,900-mile, bi-directional transmission pipeline crossing the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado and the only interstate pipeline which interconnects to Intermountain's distribution system; all gas supply received by the Company is transported by this pipeline.

NYMEX Futures
New York Mercantile Exchange is the world's largest physical commodity futures exchange. Futures are financial contracts obligating the buyer to purchase an asset (or the seller to sell an asset), such as a physical commodity, at a predetermined future date and price. Futures contracts detail the quality and quantity of the underlying asset; they are standardized to facilitate trading on a futures exchange. Some futures contracts may call for physical delivery of the asset, while others are settled in cash.

Peak Shaving
Using sources of energy, such as natural gas from storage, to supplement the normal amounts delivered to customers during peak-use periods. Using these supplemental sources prevents pipelines from having to expand their delivery facilities just to accommodate short periods of extremely high demand.

Peak Day

The coldest day of the design year; a measure used for planning system capacity requirements. For Intermountain, that day is currently January 15 of the design year.

PSIG (Pounds per Square Inch Gauge)
Pressure measured with respect to that of the atmosphere. This is a pressure gauge reading in which the gauge is adjusted to read zero at the surrounding atmospheric pressure. It is commonly called gauge pressure.

Producer
A natural gas producer is generally involved in exploration, drilling, and refinement of natural gas. There are independent producers, as well as integrated producers, which are generally larger companies that produce, transport and distribute natural gas.

Purchased Gas Adjustment or PGA
Intermountain's annual price change to adjust the cost of gas service to its customers, based on deferrals from the prior year and forward-looking cost forecasts.

Residential Customer
Any customer receiving service under the Company's RS Rate Schedule.

SCADA (Supervisory Control and Data Acquisition)
Remote controlled equipment used by pipelines and utilities to operate their gas systems. These computerized networks can acquire immediate data concerning flow, pressure or volumes of gas, as well as control different aspects of gas transmission throughout a pipeline system.

State Street Lateral (SSL)
A distinct segment of Intermountain's distribution system which serves core market customers in Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21; an Area of Interest for Intermountain.

Sun Valley Lateral (SVL)
A distinct segment of Intermountain's distribution system that serves customers in Blaine and Lincoln counties; an Area of Interest for Intermountain.

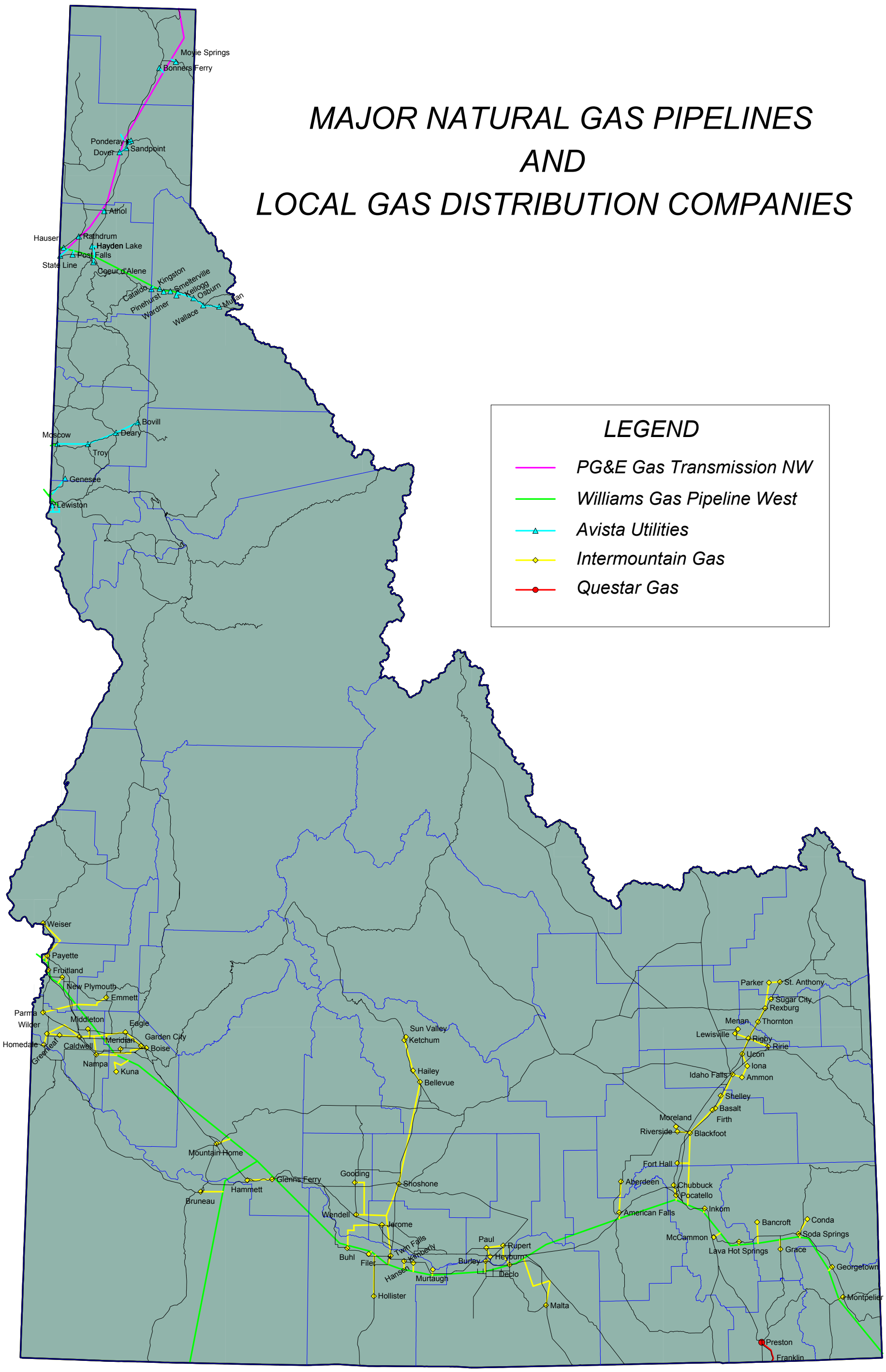
Therm
A unit of heat energy equal to 100,000 British thermal units (BTU). It is approximately the energy equivalent of burning 100 cubic feet (1 CCF) of natural gas.

Traffic Analysis Zones (TAZ)
An analysis of traffic patterns in certain high traffic areas.

Transportation Tariff
Tariffs that provide for the redelivery of a shipper's natural gas received into an interstate pipeline or Intermountain's distribution system. A transportation customer is responsible for procuring its own supply of natural gas and transporting it on the interstate pipeline system for delivery to Intermountain at one of its citygate locations.

WCSB (Western Canadian Sedimentary Basin)
A vast sedimentary basin underlying 1,400,000 square kilometers (540,000 sq mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. The WCSB contains one of the world's largest reserves of petroleum and natural gas and supplies producing more than 16,000,000,000 cubic feet (450,000,000 m3) per day of gas in 2000.

MAJOR NATURAL GAS PIPELINES AND LOCAL GAS DISTRIBUTION COMPANIES



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Capacity Release Transactional Report Summary

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Details	K	Post Date	Post Time	K Holder Name	Svc Req K	Releaser Name	Rel K	K Beg Date	K End Date	K Stat Des c	K Qty - K	Affil Desc
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Composite Exhibit 3

Cascade Natural Gas

Cascade Natural Gas 2020 Integrated Resource Plan

City of Bend Oregon's Community Climate Action Plan

2020
Integrated Resource Plan

February 26, 2021

CASCADE NATURAL GAS CORPORATION
2020 INTEGRATED RESOURCE PLAN
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Chapter 1

Executive Summary

Introduction

Cascade Natural Gas Corporation's (Cascade, CNGC, or the Company) Integrated Resource Plan (IRP or Plan) forecasts 20 years of expected system-wide customer and demand growth, and analyzes the most reliable and least cost supply side and demand side resources that could be used to fulfill future customers' gas service needs. Planning how to best meet customers' future demand includes the consideration of possible policy changes and the resulting impact on customer prices, the Company's operations, and the ability of Cascade's distribution system to serve gas reliably as regional demand increases. This plan discusses these elements that impact how the Company may serve its customers from 2021 through 2040. While the Plan cannot predict the future, it is a useful guide. The following information is a progress report and a short summary of each chapter included in this IRP. The details regarding methodologies as well as specific results are found in the chapters and appendices.

Key Points

- Each chapter provides an *at-a-glance* summary of the key points.
- The Company's two-year action plan provides the road map for future resource and planning activities.
- Load growth is forecasted to average 1.56% per year over the 20-year planning horizon.
- Cascade modeled Social Cost of Carbon as its main carbon forecast.
- The total avoided cost ranges between $0.79/therm and $1.09/therm over the 20-year planning horizon.
- Cascade projects 44 million therms of energy efficiency in Washington over the 20-year planning horizon.
- Cascade does not anticipate any material deficiency in the 2020 IRP.
- This plan was informed by five Technical Advisory Group meetings, with active engagement by stakeholders.
- Cascade continues to be fully committed to the IRP process.

Progress Report

As part of the 2018 IRP acknowledgement letter, Washington Utilities and Transportation Commission (WUTC or Staff) Staff made several suggestions on areas where Cascade could improve the IRP. The comments were regarded to validation of methods, greenhouse gas emissions modeling, modeling of significant emergency events, clarify distribution system planning priorities, continue to monitor renewable natural gas opportunities, and public participation. The progress from these recommendations are below:

Cascade has included a cross-validation section to Chapter 3, Demand Forecast. The cross-validation allows Cascade to review how well the forecast does when utilizing actual weather and customer data, rather than normal weather and forecasted customers.

Cascade has included the Social Cost of Carbon (SCC) with a 2.5% discount rate in Cascade's expected case. Cascade also included upstream emissions as part of the avoided cost calculation. The upstream emissions calculation can be found in Chapter 6, Environmental Policy. Cascade shows how the upstream emissions calculation is factored into the avoided cost in Chapter 5, Avoided Cost.

As mentioned in the 2018 IRP Acknowledgement letter, WUTC states "In its Plan, Cascade modeled several scenarios that limited supply from its various resources (including British Columbia) throughout the 20-year planning horizon." Cascade added narrative to Chapter 10, Resource Integration to further discuss these types of extreme scenarios.

Cascade's engineering group has made great strides in providing detailed justification for each distribution system plan that the company is seeking acknowledgement on. Those distribution system plans can be found in Appendix I.

The Company has continued to monitor renewable natural gas opportunities. The Company has expanded the IRP by included a brand new Renewable Natural Gas chapter. Chapter 9, Renewable Natural Gas (RNG) outlines how Cascade is monitoring and evaluating RNG opportunities.

Prior to the COVID-19 pandemic, Cascade had scheduled one TAG meeting in the city of Bellingham. Bellingham holds the largest number of customers in one city for Cascade's Washington service territory. The purpose of holding the TAG meeting in Bellingham was to increase public participation in the meeting. Unfortunately, due to the COVID-19 pandemic, all IRP meetings were held virtually. Public participation is extremely important for the IRP process and Cascade will continue to reach out to all interested parties in future IRP cycles.

Chapter 2: Company Overview

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

Cascade serves over 299,000 customers located in smaller, mostly rural communities spread across Oregon and Washington. The Company's service territory poses some challenges for operating an energy distribution system, including the fact that the areas served are noncontiguous and the weather in each area can be vastly different. To capture this, Cascade groups its citygates into seven weather zones.

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system using primarily three natural gas pipeline companies. Northwest Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta and Malin gas, and Enbridge (Westcoast Transmission) provides British Columbia gas directly into the Company's distribution system.

Chapter 3: Demand Forecast

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

Demand forecasting first requires a customer forecast. The Company developed a unique customer forecast for each citygate/rate class by incorporating population and employment growth data from Woods and Poole as well as from internal market intelligence into a dynamic regression model.

Cascade developed a normal, or expected, future weather year by shaping 30 years of proprietary, historical weather data. Heating degree day (HDD values) were assigned to each day in the model weather year. To ensure the Company will be able to serve its firm customers during extreme weather, the Company tested a system weighted peak HDD (the system weighted coldest day in the last 30 years).

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

Load growth across Cascade's system through 2040 is expected to fluctuate between 0.92% and 2.19% annually. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow at an annual rate near 1.50% and 1.23%, respectively, while industrial expects a growth rate of around 1.58%.

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

In absolute numbers, system load under normal weather conditions is expected to grow annually at an average of 5.4 million therms. Residential customers are expected to grow from 52.5% of the total core load to 53.5% of the total core load by 2040.

Load across Cascade's two-state service territory is expected to increase 1.56% annually over the planning horizon, with the Oregon portion outpacing Washington at 1.83% versus 1.24%.

Chapter 4: Supply Side Resources

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

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

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

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

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

Cascade has contracted for storage service directly from NWP since 1994. Storage is held in their Jackson Prairie underground and Plymouth Liquified Natural Gas (LNG) facilities. Jackson Prairie is located in Lewis County, Washington,

approximately ten miles south of Chehalis. Plymouth is located in Benton County, Washington approximately 30 miles south of Kennewick. Both Jackson Prairie underground storage and the Plymouth LNG facility are located directly on NWP's transmission system. In addition, Cascade has leased Mist storage from NW Natural. The Mist facility is located in Columbia County, near Mist, Oregon. Mist has a direct connection to NWP for withdrawals and injections. Storage withdrawal rates can be changed several times during an individual gas day to accommodate weather driven changes in core customer requirements.

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

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

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

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

Long-term planning is not an exact science. The Company has considered the various risks that may challenge the assumptions used in this analysis. Risk can stem from potential Federal Energy Regulatory Commission (FERC) or Canada's Energy Regulator (CER) rulings that may impact the cost or availability of gas. The

Company also considers the risk that firm supply may not be available when Cascade needs it or that pricing could vary due to any factor impacting the economy of supply and demand.

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

Chapter 5: Avoided Cost

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

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

A carbon compliance cost forecast was added in anticipation of carbon legislation. Currently, Cascade models the market driven costs to start at $78.13/metric ton CO_2e in 2021 and rising to $104.18/metric ton CO_2e in 2040. Cascade's use of this forecast does not indicate a preference towards this carbon future in Washington, but rather signifies what the Company believes is the most probable form of carbon legislation in the state.

Next, 10% was added to the commodity portion of the avoided cost to account for nonquantifiable, environmental benefits. This 10% adder was first recommended by the NWPCC based on Federal legislation.

For the 2020 IRP, the nominal system avoided costs ranges between $0.79/therm and $1.09/therm over the 20-year planning horizon. The increase over time is largely driven by the escalating cost of carbon.

Chapter 6: Environmental Policy

This chapter considers Greenhouse Gas (GHG) emission reduction policies and regulations that have the potential to impact natural gas distribution companies. In addition, this chapter examines methodologies for applying a cost of carbon to natural gas distribution companies and identifies the assumptions made in determining a 45-year avoided cost of natural gas and pairs these costs with associated two-year action items. For this IRP, as suggested by WUTC and outlined in Docket U-190730, Cascade is applying the SCC with a two and one-half percent discount rate as the main CO_2 adder in modeling.

Significant emission policy development has occurred since Cascade's last IRP. The federal government as well as policymakers at the state and local levels in Washington and Oregon have actively pursued GHG emission reductions, and primarily CO_2 emission reductions.

Cascade monitors environmental regulatory requirements in progress nationally, regionally, and locally that may have the potential to apply to a local distribution company (LDC) in the future. As of November 17, 2020, there are no direct regulations that would require the Company to reduce GHG emissions. Also, there are currently no regulations or laws applying a carbon price to CNGC operational GHG emissions or GHG emissions resulting from customer use of natural gas which Cascade sells to customers. The requirements discussed in this chapter are projected to be the most informative for the Company to determine how to model potential impacts of carbon pricing in the IRP, absent any current requirements and understanding that there is a potential for a cost of carbon to impact Cascade in the future.

Chapter 7: Demand Side Management

Demand Side Management (DSM) refers to the reduction of natural gas consumption through the installation of energy efficiency measures such as insulation, more efficient gas-fired appliances, or through load management programs. Cascade targets the saving of approximately 57 million therms systemwide over the 20-year planning horizon; 45 million therms in Washington and 12 million therms in Oregon.

Unlike supply side resources, which are purchased directly from a supplier, demand side resources are purchased from individual customers in the form of unused energy as a result of energy efficiency. The WUTC requires 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 natural gas appliances, insulated windows and doors, ventilation heat recovery systems and various other commercial/industrial

equipment. By prompting customers and influencing customers through energy efficiency outreach to reduce their individual demand for gas, Cascade can supplant the need to purchase additional gas supplies, displace or delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcements on the Company's distribution system. It's also essential to recognize that the Company can prompt and encourage customers to reduce their consumption to aid load management, but it's ultimately the choice of the end user to manage consumption by recognizing an inherent value in energy efficiency.

There are two basic types of demand side resources: base load resources and heat sensitive resources. Base load resources offset gas supply requirements throughout the year, regardless of the weather and outside conditions. Base load DSM resources include measures like high efficiency water heaters, higher efficiency cooking equipment and ozone injection laundry systems. Heat sensitive DSM resources are measures whose therm savings increase during cold weather (meaning the measure is used more often during colder 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. Examples of heat sensitive DSM measures include ceiling, floor, and wall insulation measures, high efficiency gas furnaces, and improvements to ductwork and air sealing. These types of heat sensitive measures offset more of the peaking or seasonal gas supply resources, which are typically more expensive than base load supplies.

The conservation potential for this IRP is calculated through the Applied Energy Group (AEG)'s LoadMAP model, separated into the three customer classes for individual savings assumptions, market segmentations, and end uses (heat-sensitive resources have different savings potential by climate zone for the Residential section).

Energy efficiency and conservation efforts for the Company's Oregon customers are offered through the Energy Trust of Oregon (ETO) with program planning developed through the Cascade Oregon IRP cycle.

Chapter 8: Renewable Natural Gas

Renewable Natural Gas has been introduced as its own chapter for the first time in this 2020 IRP. With there being a strong desire to mitigate the carbon footprint of the natural gas industry, the amount of information covered on RNG warranted a separate chapter. Cascade has been involved and committed to developing programs that follow RNG guidelines and rules stated in HB 1257 and SB 98.

The Company has met with several individuals and companies within the RNG industry such as producers, municipals, wastewater treatment plants, biodigesters, and landfills. Currently, none of the projects have a timeline to implement putting

RNG on the system in the near future.

Cascade has developed a potential RNG cost effectiveness methodology. Cascade is also utilizing SENDOUT® as another tool for analyzing RNG. Cascade will continue to monitor RNG guidelines and rules and incorporate any necessary changes to these models.

Chapter 9: Distribution System Planning

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

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

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

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

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

Once the optimal solution is determined, projects are ranked based on numerous criteria and are scheduled. Chapter 9, Distribution System Planning, presents a summary of costs by district and Appendix I lists all known distribution projects.

Chapter 10: Resource Integration

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

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

Utilizing the SENDOUT® resource optimization model, several portfolios were run to test the viability of acquiring incremental storage and transportation resources based on existing recourse rates and discounted rates, and via capacity release through a third party. Basin prices in the model over the 20-year planning horizon have AECO trading at a discount to Rockies, Malin, and Sumas. If DSM does not resolve all shortfalls, the acquisition of additional traditional pipeline capacity is the most reasonable resource to address most capacity shortfalls on a peak day.

Using input from these alternative resources, SENDOUT® derives a portfolio of existing and incremental resources that Cascade defines as the Preferred Portfolio. This provides guidance as to what resources should be considered to reduce unserved demand with a reasonable least cost and least risk mix of demand and supply side resources under expected pricing, weather, and growth environments.

The top-ranked candidate portfolio includes all existing resources, consideration of incremental NOVA transportation and Spire Storage, plus incremental DSM. A

more detailed discussion regarding the Company's resource integration and the results can be found in Chapter 10, Resource Integration.

Chapter 11: Stakeholder Engagement

Input and feedback from Cascade's Technical Advisory Group (TAG) is an important resource for ensuring the IRP includes perspectives beyond the Company's and is responsive to stakeholders' concerns. Cascade held five public TAG meetings with internal and external stakeholders. Due to travel and social distancing restrictions as a result of the COVID-19 pandemic, all meetings were held virtually using Microsoft Teams. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest Local Distribution Companies, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Public Counsel, Citizens' Utility Board, Washington Department of Ecology, Northwest Energy Coalition, and the Alliance of Western Energy Consumers. Cascade has a dedicated internet webpage where customers and parties can view the IRP timeline, TAG presentations and minutes, as well as current and past IRPs. This information can be found at https://www.cngc.com/rates-services/rates-tariffs/washington-integrated-resource-plan.

Chapter 12: Two-Year Action Plan

Figure 1-1 on the following page shows Cascade's Two-Year Action Plan. Further descriptions can be found in Chapter 12, Two-Year Action Plan.

Figure 1-1: Highlights of 2020 Action Plan

Functional Area	Anticipated Action	Timing
Resource Planning	Cascade will: • Attend other regional LDC IRP meetings; • Work with NWP on realigning MDDOs; • Develop modeling scenarios that represent pipeline OFOs; • Improve the alignment of resource/costs between the PGA and the IRP; • Develop more scenarios that address changing Canadian Markets; • Develop scenarios that consider sensitivities around municipal natural gas bans or other deep decarbonization possibilities in Cascades service territory; • Add RNG as a candidate portfolio; and • Investigate the cost and feasibility of a potential hydrogen plant as an alternative resource.	Ongoing, for inclusion in 2022 IRP.
Avoided Cost	Cascade will: • Model sensitivity analysis regarding upstream emissions.	Ongoing, for inclusion in 2022 IRP.
Demand	Cascade will: • Add wind in the stochastic weather analysis; • Investigate climate change modeling scenarios; and • Develop, in collaboration with Staff and stakeholders, a new methodology for peak day. • Discuss, for the 2022 IRP, any potential impacts the COVID-19 crisis may have on demand.	Ongoing, for inclusion in 2022 IRP.
Environmental Policy	The Company will execute the Environmental Policy action items as described on page 12-3 and 12-4.	Ongoing, for inclusion in 2022 IRP.
DSM (Energy Efficiency)	The Company will execute the Demand Side Management action items as described on page 12-4.	Ongoing, for inclusion in 2022 IRP.
Renewable Natural Gas	Cascade will: • Continue to develop and update the cost-effective evaluation tool. • Continue to hold discussions with potential RNG partners. • Develop necessary internal protocols to offer RNG services to customers. • Develop a voluntary RNG program under RCW 80.28.390.	Ongoing, for inclusion in 2022 IRP.
Distribution System Planning	Cascade will: • Implement various stages or review of the of the list of projects that require an increase in capacity as shown in Appendix I. • Construct citygate upgrades, over the next several years, in Aberdeen, Kennewick, and Longview. • Focus on projects to include pipe upgrades as well as increased pipe capacity, while continuing to maintain compliance with Maximum Allowable Operation Pressure regulations.	Ongoing over the next four to five years.

Chapter 2

Company Overview

Company Overview

Key Points

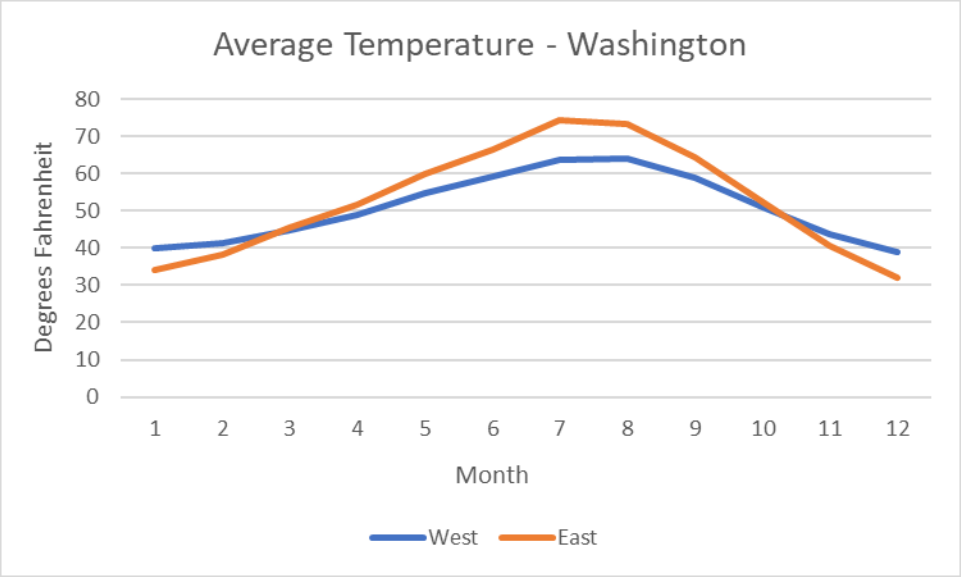
- Cascade serves diverse geographical territories across Washington and Oregon.
- Cascade's primary pipelines are NWP, GTN, and Enbridge, also known as WCT, with access to three other pipelines.
- Core customers represent 25% of total throughput, while non-core customers represent 75% of total throughput.
- Cascade is a subsidiary of MDU Resources Group, Inc. based in Bismarck, North Dakota.

Cascade Natural Gas Corporation (CNGC or Cascade or Company) has a rich history that began 68 years ago when business leaders and public officials in the Pacific Northwest initiated a campaign to bring natural gas to the region to replace other more expensive fuels. In 1953, five small utilities serving fifteen communities merged to form Cascade. Over the years, Cascade continued to grow, merging with and purchasing other natural gas providers. The Company stock first traded on the New York Stock Exchange in 1973. In 2007, Cascade merged with Montana Dakota Utilities (MDU) Resources Group, Inc. which is headquartered in Bismarck, North Dakota. Cascade's headquarters moved from Seattle, Washington to Kennewick, Washington in 2010.

Today, Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a diverse economic base as well as varying climatological areas. Cascade delivers natural gas service to more than 299,000 customers with approximately 77,000 customers in Oregon and 222,000 customers in Washington. The Company's customers reside in 96 communities--28 in Oregon and 68 in Washington. Cascade's service area consists of smaller, rural communities in central and eastern Oregon, as well as communities across Washington.

The climate of Cascade's service territory is almost as diverse as its geographical extension. The western Washington portion of the service territory, nicknamed the I-5 corridor, has a marine climate with occasionally significant snow events. In general, the climate in the western part of the service territory is mild with frequent cloud cover, winter rain, and warm summers. Cascade's eastern Washington service territory has a semi-arid climate with periods of arctic cold in the winter and heat waves in the summer. Figure 2-1 compares the average temperatures by month of the two regions. Oregon's service territory is in rural areas throughout northern central and central Oregon as well as eastern Oregon. All regions of Oregon have semi-arid climates with periods of arctic cold in the winter and heat waves in the summer.

Figure 2-1: Average Temperature by Region

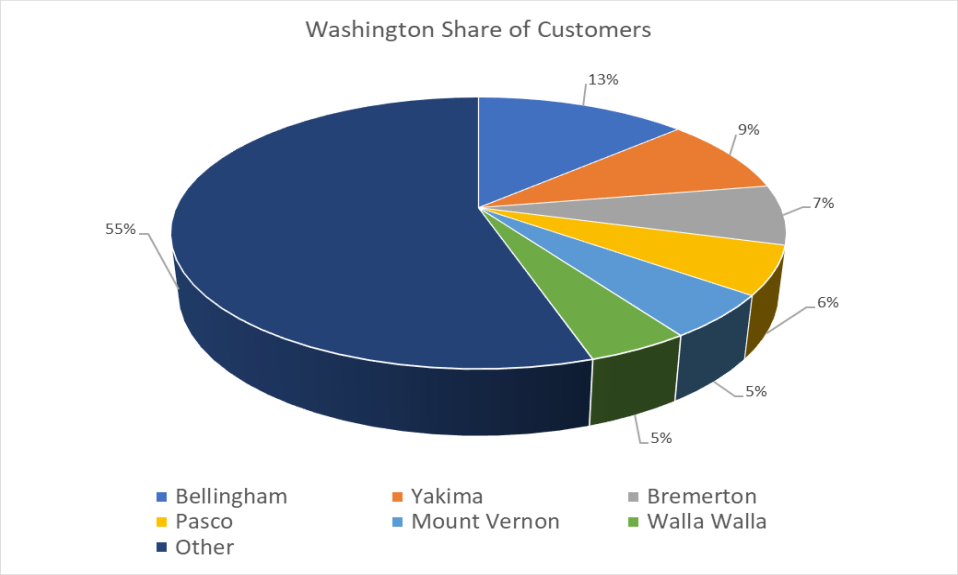


Below are some of the more populated towns within the regions Cascade provides distribution service:

- **Northwest** – Bellingham, Mt. Vernon, Oak Harbor/Anacortes, the Kitsap Peninsula, the Grays Harbor area and Kelso/Longview;
- **Central** – Sunnyside, Wenatchee/Moses Lake, Tri-Cities, Walla Walla and Yakima areas; and
- **Southern** – Bend and surrounding communities, Ontario, Baker City and the Pendleton/Hermiston areas.

Figure 2-2 shows a breakdown of Cascade's Washington customer density by town. A map of Cascade's certificated service territory is provided as Figure 13-13 in Chapter 13, Glossary and Maps.

Figure 2-2: Customer Density by Town in Washington



Pipeline and Basin Locations

Cascade purchases natural gas from a variety of suppliers and transports gas supplies to its distribution system using three natural gas pipeline companies. Northwest Pipeline LLC (NWP) provides access to British Columbia and domestic Rocky Mountain gas, Gas Transmission Northwest (GTN) provides access to Alberta and Malin gas, and Enbridge (WCT) provides British Columbia gas directly into the Company's distribution system. Cascade also holds upstream transportation contracts on TransCanada Pipeline's Foothills Pipeline (FHBC), NOVA Gas Transmission Ltd. (also known as NGTL), and Ruby Pipeline. More information about the pipelines and the supply basins is provided in Chapter 4, Supply Side Resources. Maps of select pipelines are found in Chapter 13, Glossary and Maps.

Core vs Non-Core Service

Cascade offers core service, which is the procurement of gas supply from an upstream basin, such as Sumas or AECO, that is then transported to Cascade's citygates. From the citygate, Cascade then delivers gas on its distribution system to the end-use customer. Although Cascade offers core service to all its customers, not all of them take advantage of this type of firm service.

In 1989, concurrent with the passage of the Natural Gas Wellhead Decontrol Act, Cascade began allowing its large volume customers to purchase their own gas

supplies and gas transportation services upstream of Cascade's distribution system.[1] These customers, referred to as large volume transportation or non-core customers, procure their own supply and transportation through third parties such as marketers. Cascade is only responsible for the distribution of non-core gas supply from the upstream pipeline citygate to the point of delivery at the customer's site. The Company currently has approximately 247 large volume customers who have elected this type of non-core service.

Since the Company does not provide gas supply and upstream pipeline transportation capacity resources to non-core customers, the Company does not plan for non-core customers in the upstream resource analysis of its Integrated Resource Plan (IRP). However, non-core demand is a consideration in distribution planning. While it is not the core substance of the IRP, it is included in Chapter 9, Distribution System Planning.

In 2020, Cascade's residential customers represent approximately 13% of the total natural gas delivered on Cascade's system, while commercial customers represent roughly 10%, and the core industrial customers account for around 2% of total gas throughput. The remaining non-core industrial customers represent the balance of the 75% of total throughput.

Company Organization

In 2007, Cascade became a subsidiary of MDU Resources Group, Inc., a multidimensional regulated energy delivery and construction materials and services business, operating in 43 states and traded on the New York Stock Exchange under the symbol MDU. Cascade, with headquarters in Kennewick, Washington, is part of its utility group of subsidiaries. MDU Resources Group's utility companies, when combined, serve more than one million customers. Cascade distributes natural gas in Oregon and Washington. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Figure 2-3 provides a geographical representation of the various services/territories served by MDU Resources. Figure 2-4 shows the MDU Resources Electric and Natural Gas Services and Territory.

[1] *See* Natural Gas Wellhead Decontrol Act of 1989 amends the Natural Gas Policy Act of 1978 to declare that the price guidelines for the first sale of natural gas do not apply to: (1) expired, terminated, or post-enactment contracts executed after the date of enactment of this Act; and (2) certain renegotiated contracts. Decontrols as of May 15, 1991, natural gas produced from newly spudded wells. Repeals permanently wellhead price controls beginning on January 1, 1993.

Figure 2-3: MDU Resources Services and Territory

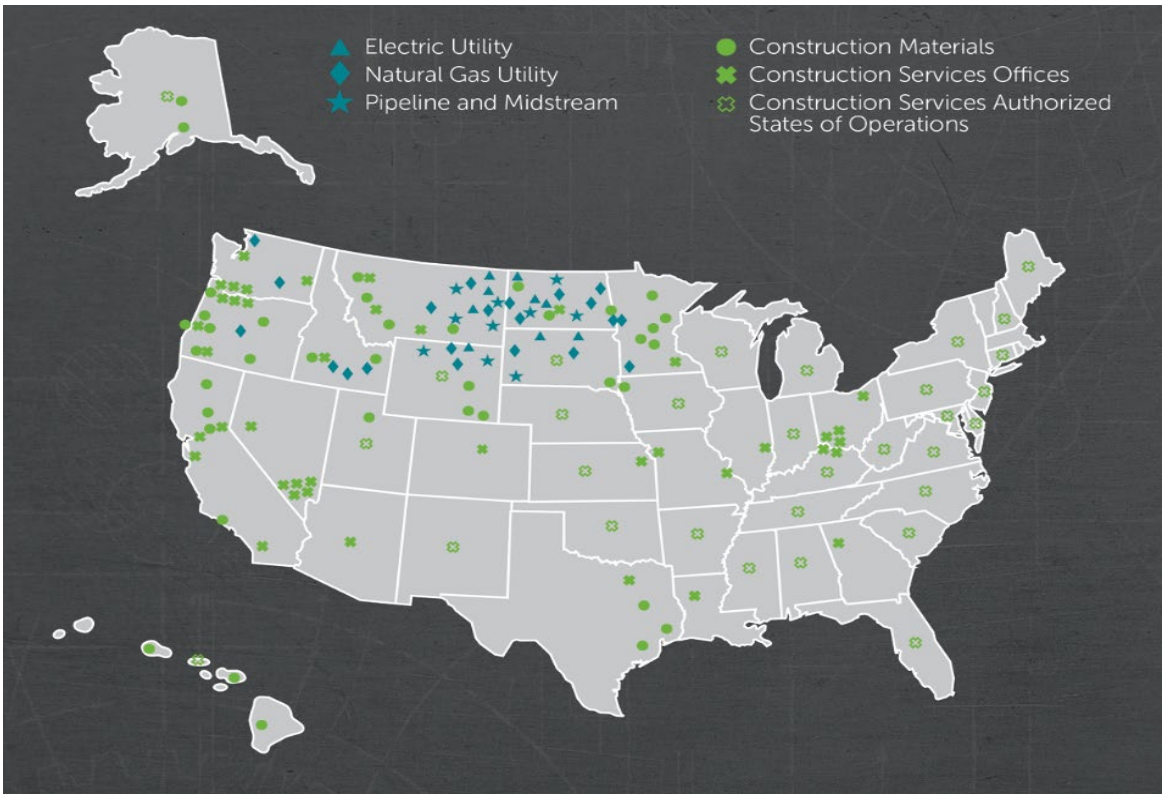
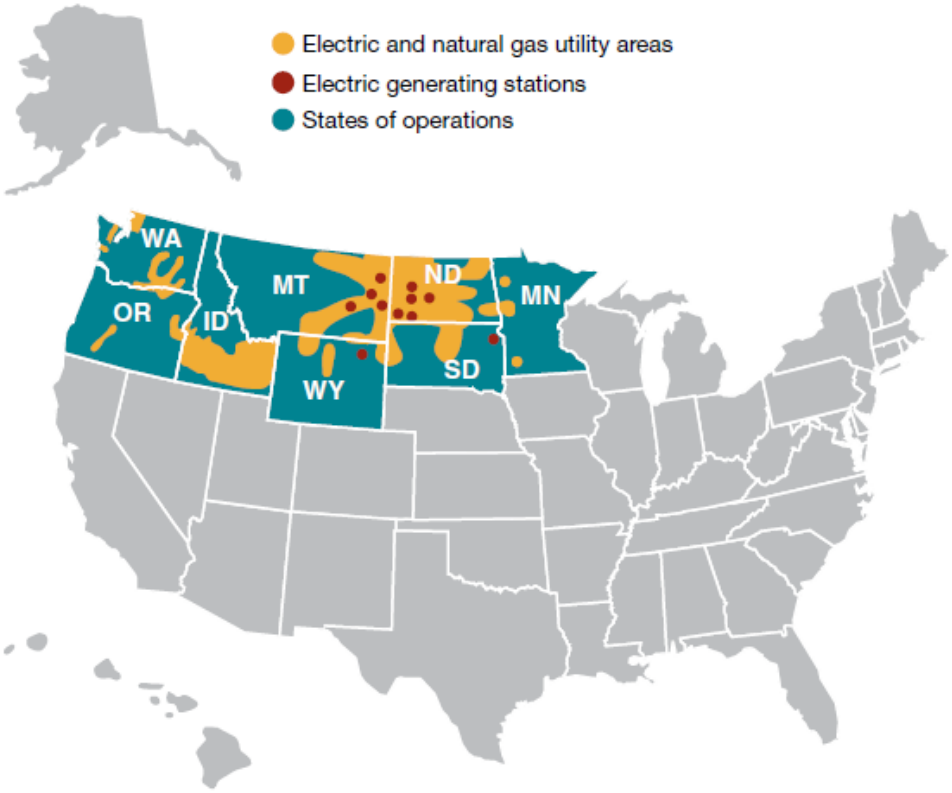


Figure 2-4: MDU Resources Electric and Natural Gas Services and Territory



Chapter 3

Demand Forecast

Overview

Each year Cascade develops a 20-year forecast of customers, therm sales, and peak requirements for use in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes. Sources of this forecast include historic data, market intelligence, and regional economic data from Woods & Poole. This forecast is a robust portfolio of estimates created by expanding a single best-estimate forecast, which includes various potential economic, demographic, and marketplace eventualities, into scenarios such as low, expected, and high growth. The scenarios are used for distribution system enhancement planning and as inputs in optimization models to determine the reasonable least cost, least risk mix of supply and energy efficiency resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Key Points

- Cascade initiates its forecast with analyses of demand area, HDDs, and wind.
- Peak day is analyzed deterministically with coldest day in 30 years, and stochastically using 10,000 Monte Carlo simulated draws.
- Cascade uses a 60 °F reference temperature to calculate HDDs.
- The Company utilizes dynamic regression modeling techniques for customer and annual demand forecasts.
- High and low scenarios are included and alternative forecasting assumptions were considered.
- Cascade expects system load growth to average 1.56% per year over the 20-year planning horizon.
- For methodological changes from previous IRPs, please refer to Appendix K.
- Uncertainties in the future, such as economic and long-term weather conditions, as well as future legislation, may cause differences from the Company's forecast.

Demand Areas

For the 2021-2040 planning horizon, Cascade continued to forecast at both the citygate and rate class levels. Cascade has a total of 76 citygates of which nine citygates feed only non-core customers and the remaining 67 serve at least one core customer. Of the 67 citygates that serve core customers, twenty are grouped into eight different citygate loops. Therefore, Cascade forecasts a total of 55 areas. Each of these areas contain multiple rate classes, resulting in approximately 200 individual dynamic regression models. Each citygate is assigned to a weather location. For this IRP, the Company assigned the citygates to the closest weather location by distance. The citygate results are rolled up into zones and districts which segregate Cascade's system based on pipelines and weather, as shown in Appendix B. Figure 3-1 provides a cross reference for the demand areas.

Figure 3-1: Demand Areas

Citygate	Loop	State	Weather Location	Zone
7TH DAY SCHOOL		WA	Yakima	10
A/M RENDERING	Sumas SPE Loop	WA	Bellingham	30-W
ACME		WA	Bellingham	30-W
ARLINGTON		WA	Bellingham	30-W
ATHENA		OR	Pendleton	ME-OR
BAKER		OR	Baker City	24
BELLINGHAM 1 (FERNDALE)	Sumas SPE Loop	WA	Bellingham	30-W
BEND	Bend Loop	OR	Redmond	GTN
BREMERTON (SHELTON)		WA	Bremerton	30-S
BURBANK HEIGHTS	Burbank Heights Loop	WA	Walla Walla	20
CASTLE ROCK		WA	Bremerton	26
CHEMULT		OR	Redmond	GTN
DEHAWN DAIRY		WA	Yakima	10
DEMING		WA	Bellingham	30-W
EAST STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
FINLEY		WA	Walla Walla	20
GILCHRIST		OR	Redmond	GTN
GRANDVIEW		WA	Yakima	10
HERMISTON		OR	Pendleton	ME-OR
HUNTINGTON		OR	Baker City	24
KALAMA #1		WA	Bremerton	26
KALAMA #2		WA	Bremerton	26
KENNEWICK	Kennewick Loop	WA	Walla Walla	20
LA PINE		OR	Redmond	GTN
LAWRENCE		WA	Bellingham	30-W
LDS CHURCH		WA	Bellingham	30-W
LONGVIEW-KELSO	Longview South Loop	WA	Bremerton	26
LYNDEN	Sumas SPE Loop	WA	Bellingham	30-W
MADRAS		OR	Redmond	GTN
MCCLEARY (ABERDEEN/HOQUIAM)		WA	Bremerton	30-S
MILTON-FREEWATER		OR	Walla Walla	ME-OR
MISSION TAP		OR	Pendleton	ME-OR
MOSES LAKE		WA	Yakima	20
MOUNT VERNON	Sedro-Woolley Loop	WA	Bellingham	30-W
MOXEE (BEAUCHENE)		WA	Yakima	11
NORTH BEND		OR	Redmond	GTN
NORTH PASCO	Burbank Heights Loop	WA	Walla Walla	20
NYSSA-ONTARIO		OR	Baker City	24
OAK HARBOR/STANWOOD	East Stanwood Loop	WA	Bellingham	30-W

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

Weather

Historical weather data is provided by a contractor, Schneider Electric. Historically, Cascade has accessed data from NOAA (National Oceanic and Atmospheric Administration), but found many months/locations with missing data. The current forecast uses 30 years of recent history as the normal or expected weather. The forecast model takes the 30 previous years, converts the data to heating degree days (HDDs), then averages the HDDs into average days to create a normal or expected year. Cascade has seven weather locations with four located in Washington and three in Oregon. The four locations in Washington are Bellingham, Bremerton, Walla Walla, and Yakima.

Heating Degree Days

HDD values are calculated with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 60 °F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to significantly rise.[1]

Peak Day HDDs

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

The deterministic peak day that was analyzed in the forecast model is a system-wide weighted HDD coldest in 30 years value.

This peak day will give Cascade the deterministic outcome with varying amounts of demand. The deterministic peak HDD methodology allows Gas Supply to plan for the highest peak event during a heating season.

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

For SENDOUT®, Cascade uses the system-wide maximum peak HDDs method. Cascade applies the HDDs experienced on December 21, 1990, to each of the regressions in the forecast model. For example, all citygates associated with the Yakima weather station use the HDD for Yakima on December 21, 1990, and similarly for all the other weather stations and citygates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for

[1] The historical threshold for calculating HDD has been 65 °F. However, as discussed in prior IRPs, Cascade has determined that lowering the threshold to 60 °F produces more accurate results for the Company's service area.

each citygate. Applying December 21, 1990, weather temperatures to today's forecast methodology gives Cascade an accurate representation of the demand the Company could expect to experience if this weather happened during the planning horizon.

Cascade is actively expanding its peak day methodology to include stochastic elements such as Monte Carlo analysis. Cascade is also considering different historical weather windows to better understand the effects of climate change on Cascade's service territory, which will be further expanded in the next IRP cycle. More on this peak day analysis can be found on page 3-10. Cascade will also continue to investigate how various peak day standards affect the core demand load areas which are short of capacity. This investigation will include (but not be limited to) analysis of how other regional utilities look at peak day, discussions with the various weather services, and continued dialogue with Commission Staff and other interested parties.

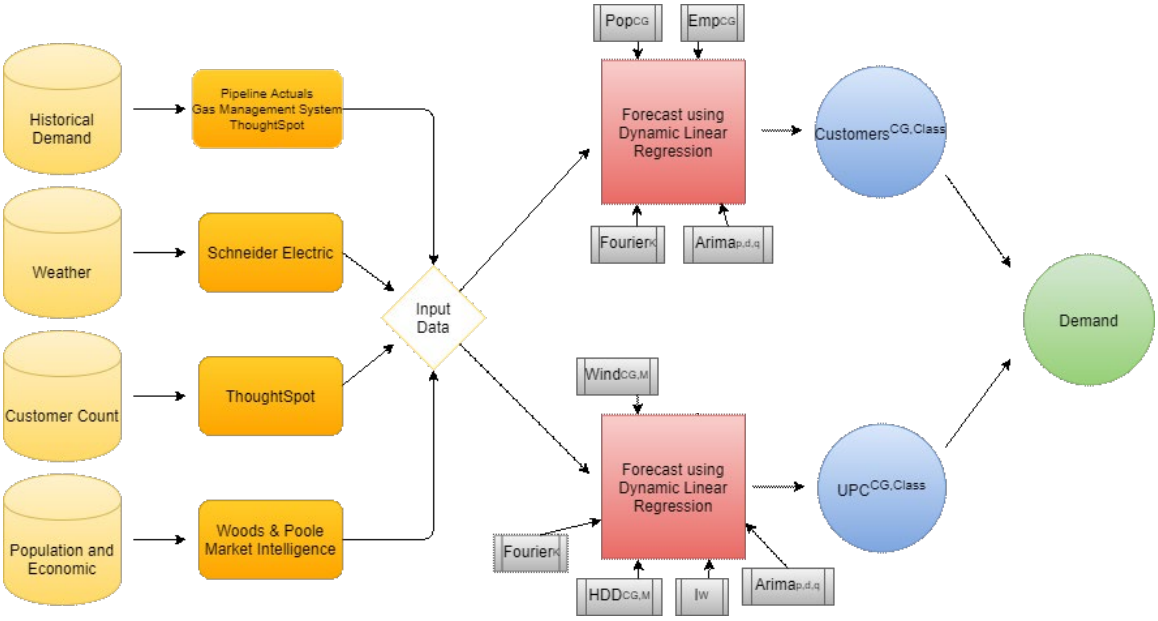
Wind

Wind values are calculated with the daily average wind speed, which is the simple average of the high and low wind speeds for a given day. Wind speeds are also weather location specific, similar to HDDs.

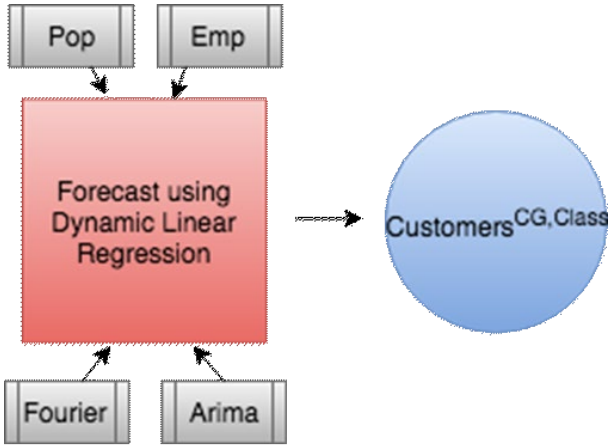
Demand Overview

Figure 3-4 provides a roadmap for Cascade's demand forecast. The inputs are displayed along with their sources in yellow and gold. The customer forecast and use-per-customer (UPC) forecast are shown in red along with their respective inputs into the model. Finally, the customer forecast is multiplied by the use-per-customer forecast to create the final demand forecast.

Figure 3-4: Demand Forecasting Process Overview



Customer Forecast Methodology



Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short- and long-term. Cascade uses population and employment growth data from Woods & Poole (W&P). Since the first quarter of 2020, Cascade has and will continue to monitor the COVID-19 impacts. Since Cascade relies on W&P for population and employment growth data, the Company is providing an update from W&P about the impacts of COVID-19 on those projections. W&P states "Despite significant 2020 impacts, COVID -19 itself does not appear to have made a quantifiable long-term economic impact that would affect forecasts: productive land area in the U.S. is still usable, productive capital (i.e. factories) are still in place, and the size of labor force has not been reduced significantly."[2] W&P growth forecasts are provided at the county level. It should be noted that W&P forecasts are adjusted when the internal intelligence about a demand area indicates a significant difference from W&P regarding observed economic

[2] Woods & Poole's 2020 State Profile: State and County Projections to 2020

trends. Cascade utilizes dynamic regression models for the customer forecast as well as regression models for the UPC forecast, which will be discussed in the next subchapter. Below is the formula the Company used to run the regressions:

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

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class$
- $Pop^{CG} = Population\ by\ Citygate$
- $Emp^{CG} = Employment\ by\ Citygate$
- $Fourier = Terms\ used\ to\ capture\ seasonal\ patterns$
- $k = Number\ of\ Fourier\ terms\ used\ in\ model$
- $ARIMA\epsilon(p,d,q) =$
  $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model approximately 200 times to account for each customer class by citygate. The Company begins by testing seven different combinations of the regressors in both dynamic regression models and one Autoregressive Integrated Moving Average (ARIMA) model. The dynamic regression models test Fourier, Population, Employment, Population + Fourier, Employment + Fourier, and Employment + Population + Fourier. The last model is called an ARIMA model, which uses ARIMA terms and no regressors. Unlike the dynamic regression models, the 'ARIMA Only' model's ARIMA term is not strictly modeling the errors, but is used as a model for the entire data set. The method used to compare and select a model is called the AIC, or the Akaike Information Criterion. This is a measure of the relative quality of statistical models, relative to each of the other models. In each of the models, except for the 'ARIMA Only' model, an ARIMA term is used to capture any structure in the errors (or residuals) of the model. In other words, there could be predictability in the errors, so they could be modeled as well. If the data is non-stationary, the ARIMA function will difference the data. Most times, the data does not require differencing, or only needs to be differenced once. Once the best model is selected for each customer class by citygate, a forecast is performed using the selected model.

Customer count and therm forecasts are augmented by revisions to the base data and output to create a portfolio of potential scenarios. Low and high growth scenarios are created from the confidence intervals from the forecast model. These scenarios, along with the original, best-estimate, expected scenario encapsulate a range of most-likely possibilities given known data. The most recent W&P data indicates an average annual population growth of 0.852% between 2021 and 2040 for Cascade's service territory. The projected customer growth is provided in Appendix B. Based on historical experience and given expected weather, Cascade expects system load will likely remain within a range bound by the low and high growth scenarios.

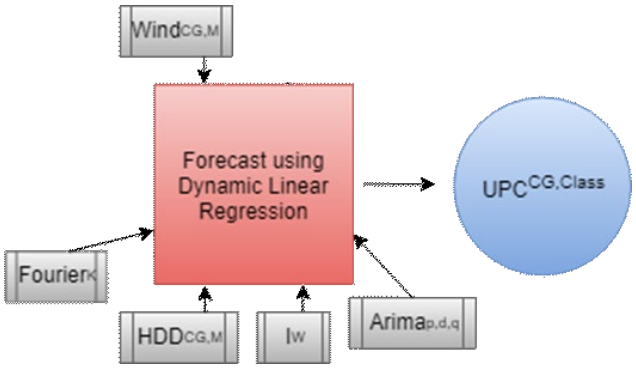
Cascade locked in the forecast model on June 10, 2020 as it is a key input for several other aspects of this IRP.

Among other reasons, the Company believes that high projected growth in the following regions is supported by the provided quantitative analysis:

- Burbank Heights Loop is expected to see a year over year average growth of 1.89%. This loop consists of the Pasco, North Pasco, and Burbank Heights citygates. These are located in southeastern Washington. Pasco sits in one of the fastest growing counties in the state, Franklin County. Future job growth is optimistic.[3]
- Kennewick Loop is expected to see a year over year average growth of 1.84%. This loop consists of the Richland Y, Kennewick, and Southridge citygates. These are located in southeastern Washington. Many new developments are a direct result of high population growth rates and optimistic job outlooks.[4]
- Longview South Loop is expected to see a year over year average growth of 1.94%. This loop consists of the South Longview and Kelso citygates. Both cities are located in western Washington. Both cities are seeing steady population growth coupled with optimistic job growth estimates.[5]

According to Tri-cities Business News and Washington's Office of Financial Management, the primary driver behind Washington's population growth is migration with net migration accounting for 76% of the population growth. The remaining 24% consisted of natural increases (births minus deaths).[6]

Use-Per-Customer Forecast Methodology



As previously mentioned, Cascade utilizes regression models for the UPC part of the demand forecast as well. Sources for the inputs into this model are pipeline actuals, Cascade's gas management system, and Cascade's billing system data from ThoughtSpot. Cascade developed the UPC coefficient by gathering historical pipeline demand data by day. The pipeline demand data includes core and non-core usage. The non-core data is

[3] *See* According to bestplaces.net, worldpopulationreview.com, and city-data.com
[4] *See* According to bestplaces.net, worldpopulationreview.com, and city-data.com
[5] *See* According to bestplaces.net, worldpopulationreview.com, and city-data.com
[6] *See* https://www.tricitiesbusinessnews.com/2020/07/tri-city-regions-population/

backed out using Cascade's measurement data stored in the Company's Aligne energy transaction system which leaves only the daily core usage data. The daily data is then allocated to a rate schedule for each citygate by using Cascade's ThoughtSpot system, which analyzes the therms billed for each rate class. This data is then divided by number of customers to come up with a UPC number for each day and for each rate schedule at each citygate.

Below is the model used for the UPC forecast:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG,M} + \alpha_2 I_w + \alpha_3 WIND^{CG,M} + Fourier(k) + ARIMA(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} = Heating\ Degree\ Days\ from\ Weather\ Location$
- $m = month$
- $w = weekend$
- $I = Indicator\ variable, 1\ if\ weekend, and\ 0\ if\ weekday.$
- $WIND^{CG} = Daily\ average\ wind\ speed\ from\ Weather\ Location$
- $Fourier(k) = Captures\ seasonality\ of\ k\ number\ of\ seasons.$
- $ARIMA(p,d,q) = Indicates\ model\ has\ p\ autoregressive\ terms,$
  $d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model for each of the 55 citygates and citygate loops by customer class where applicable, resulting in approximately 200 models. Cascade starts with the above model for Residential, Commercial, and Industrial customer classes. A change in methodology from previous IRPs involves keeping variables in the model that may appear non-significant on a statistical level but relevant on an economic level. This could be a shoulder month, i.e. September, showing insignificance in a model but economically known to affect the annual load shape of residential customers. Also, Cascade now runs the UPC forecast with Fourier and ARIMA terms.

Peak Day Forecast Methodology

Cascade's methodology for peak day forecasting is similar to its forecast of demand. For a deterministic forecast, Cascade utilizes the same dynamic regressions as before but with a peak day HDD inserted. This peak day HDD comes from the coldest on record in the last 30 years. Once this peak day is inserted for every year of the forecast, Cascade deterministically derives a peak day usage forecast.

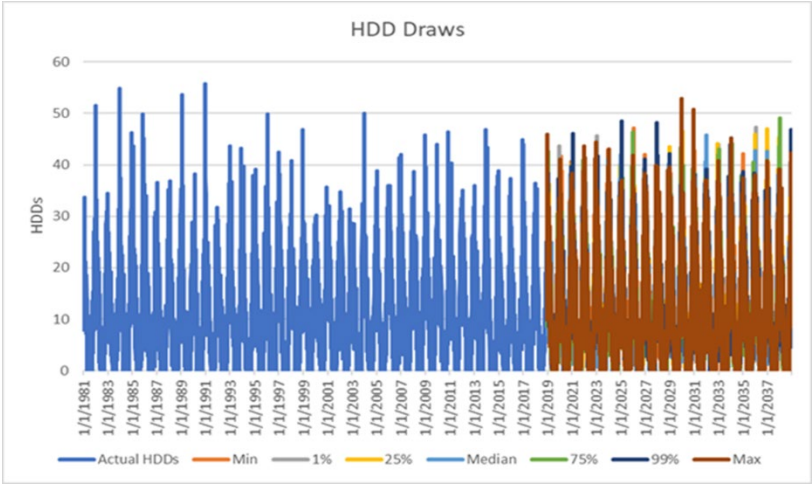
The Company also utilizes Monte Carlo simulation to stochastically analyze the peak day behavior. Through the statistical program R, Cascade runs 10,000 Monte Carlo draws in each weather zone, making sure to correlate the draws based on historical

correlations between each weather zone. This results in 10,000 draws of various weather behavior based on historical averages, standard deviations, and correlations between weather zones. Further discussion regarding the Monte Carlo methodology can be found in Chapter 10, Resource Integration.

In this stochastic analysis, Cascade analyzed many attributes, including the minimum, the maximum, and percentiles such as the 1st, 25th, 75th, and the 99th. The 99th percentile is then used to calculate the Value-at-Risk (VaR) metric to compare with the VaR limits discussed in Chapter 10.

Figure 3-5 displays the historical weather data along with the Monte Carlo simulated weather forecast. The historical weather data represents actual HDDs. The 10,000-draw simulation includes the following draws: Minimum, 1%, 25%, median, 75%, 99%, and maximum.

Figure 3-5: Historical vs. Monte Carlo Simulated Weather



Scenario Analysis

Cascade stress tests the load forecast in SENDOUT® by using alternative forecasting assumptions. These alternative forecasting assumptions refer to changing factors that influence demand. Alternative assumptions include high and low customer growth, and a stochastic study of weather using Monte Carlo simulations. These altered assumptions provide an effective tool for analyzing and stress testing the forecasts. Figure 3-6 identifies the list of scenarios.

Figure 3-6: Growth and Weather Scenarios

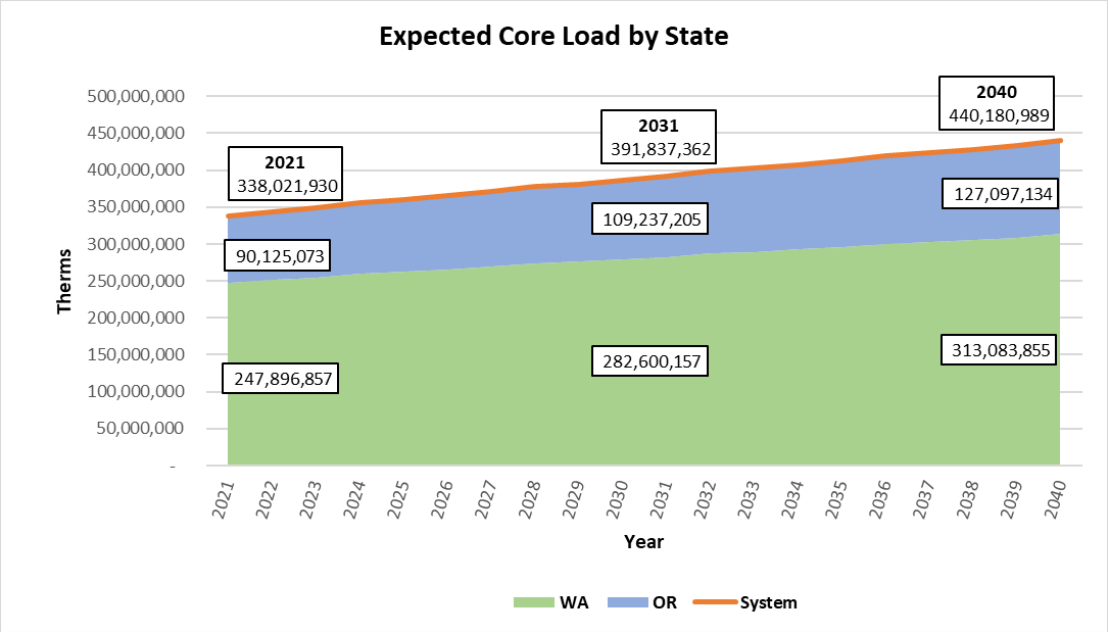
Scenario	Weather	Growth	UPC
Expected Case	Expected	Expected	Expected
Low Growth	Monte Carlo Weather	Low	Expected
High Growth	Monte Carlo Weather	High	Expected

The base case contains expected weather, customer growth, and use per customer. The base case also has one max peak day event for each weather zone. Expected weather is the average weather over the past 30 years. High and low growth scenarios, discussed more on page 3-18, explain that Cascade uses modifiers to represent higher than expected growth and lower than expected growth. Stochastic tests such as weather on demand are only to show how it can impact demand over the 20-year planning horizon. Cascade also performs a deep sensitivity analysis utilizing Monte Carlo runs for other variables such as price. Monte Carlo analysis is discussed further in Chapter 10.

Forecast Results

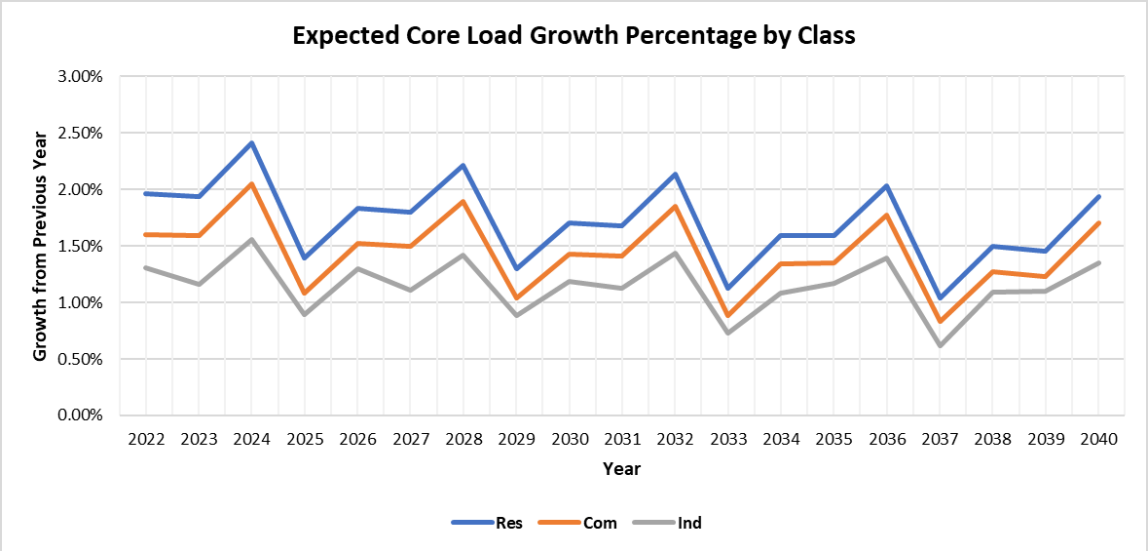
Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.56% over the planning horizon, with the Oregon portion outpacing Washington, 1.83% versus 1.24%. Figure 3-7 shows the expected core load volumes by state.

Figure 3-7: Expected Core Load by State (Volumes in Therms)



Load growth across Cascade's system through 2040 is expected to fluctuate between 0.92% and 2.19% annually, accounting for leap years. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.50% and 1.23%, while industrial expects a growth rate of approximately 1.58%. Figure 3-8 shows the percentage of core growth by class over the planning horizon.

Figure 3-8: Expected Core Load Growth Percentage by Class



In absolute numbers, system load under normal weather conditions is expected to grow annually at an average of 5.4 million therms. A majority of core load today is residential. Cascade projects the ratio between residential, commercial, and industrial to increase in favor of residential customers. Residential customers are expected to grow from 52.5% of the total core load to 53.5% of the total core load by 2040. Figure 3-9 compares the total system annual therm usage forecast of this IRP to past IRPs dating back to 2011. Figure 3-10 displays the relative percentage relationship of expected loads by class.

Figure 3-9: System Load Comparison to Previous IRPs

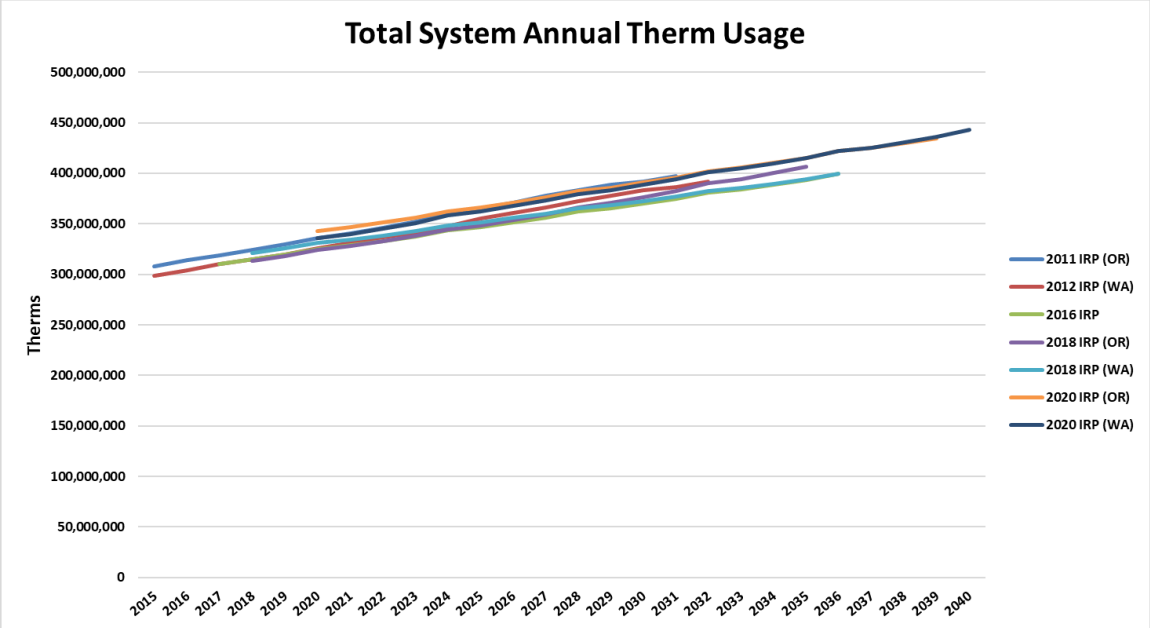
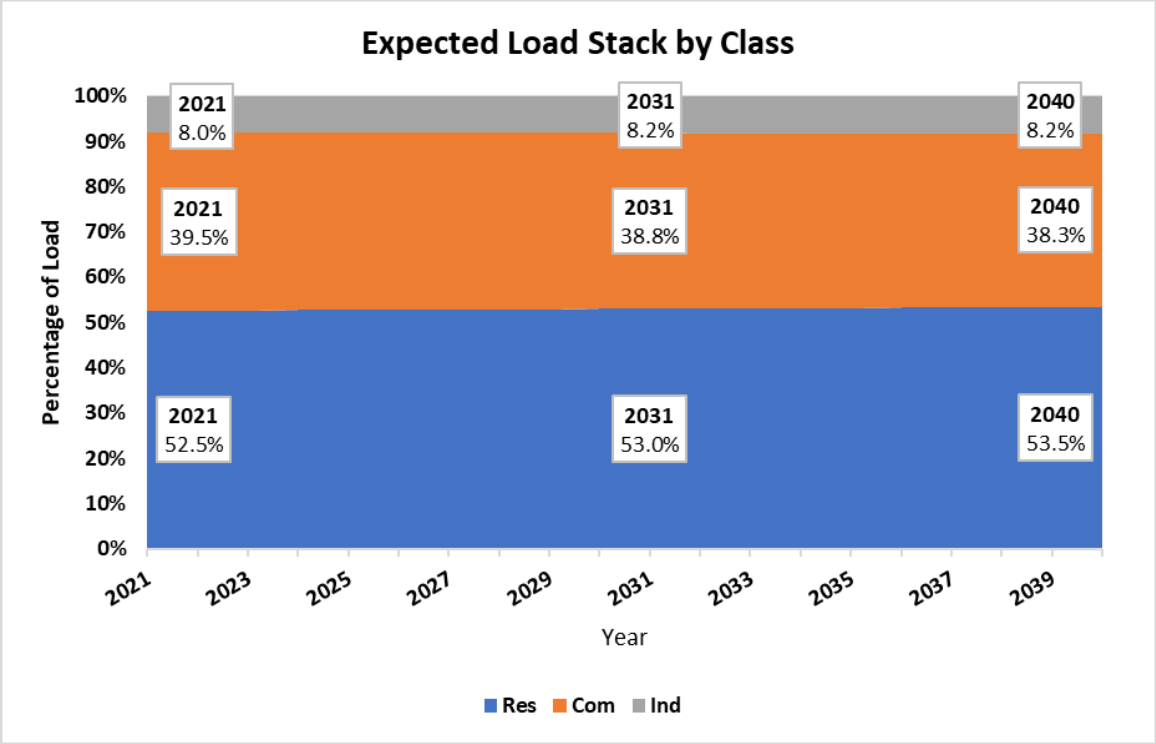
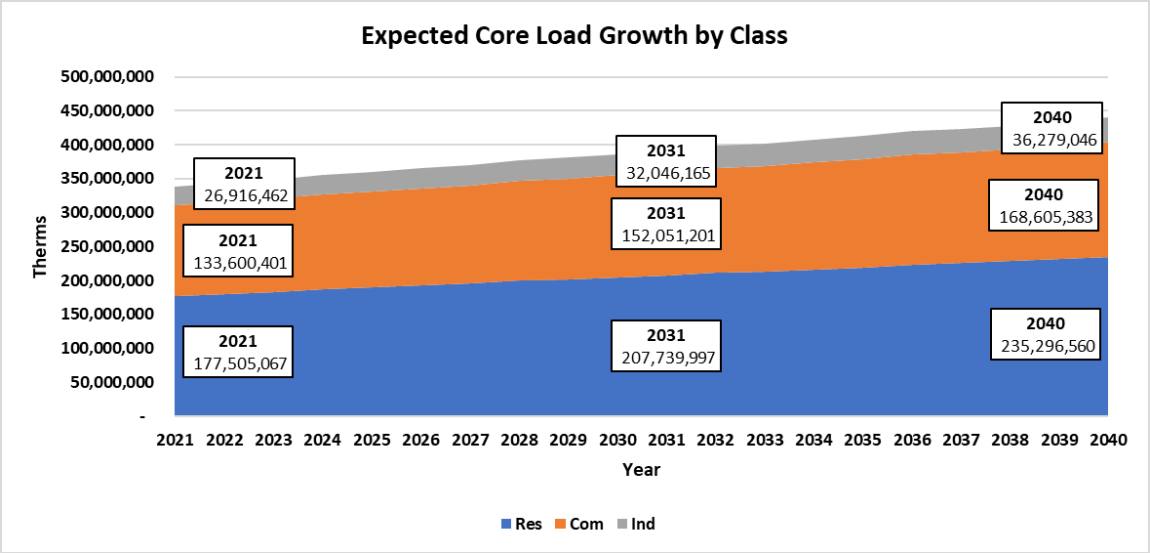


Figure 3-10: Expected Load Stack by Class



Cascade expects residential customers to increase load at an annual average growth of approximately 3 million therms and commercial core customers to increase load at an annual average growth of approximately 1.8 million therms over the 20-year planning horizon. Industrial customers are expected to increase load at an annual average growth of approximately 493,000 therms over the same period. Figure 3-11 displays the expected core load volumes by class.

Figure 3-11: Expected Load Growth by Class (Volumes in Therms)



Load growth is primarily a result of increased customer counts. The number of commercial and industrial customers is expected to increase at a slightly faster rate than therm usage, whereas residential customer growth is similar to the residential load growth. Figure 3-12 displays the expected customer counts by class.

Figure 3-12: Expected Customer Counts by Class

Year	Residential	Commercial	Industrial
2021	267,686	37,703	767
2026	294,189	40,745	839
2031	320,672	43,785	912
2036	347,104	46,811	986
2040	368,209	49,225	1,042
Average Annual Change	**1.69%**	**1.41%**	**1.63%**

Geography

Southeastern Washington is a major driver in the growth rate. This area has multiple citygates serving counties with large increases in growth rates. Figure 3-13 shows the 20-year system load by each of Cascade's pipeline zones. Figure 3-14 shows the average annual percentage growth of load by each pipeline zone over the planning horizon. For a map of the pipeline zones, please refer to Figures 13-9 and 13-10. For a detailed list, Figure 3-1 gives information on each citygate's zone. Lastly, Figure 3-15 displays the expected system core peak day growth over the planning horizon. Peak day average annual growth is expected to be approximately 1.58%.

Figure 3-13: System 20-Year Load by Pipeline Zone (Volumes in Therms)

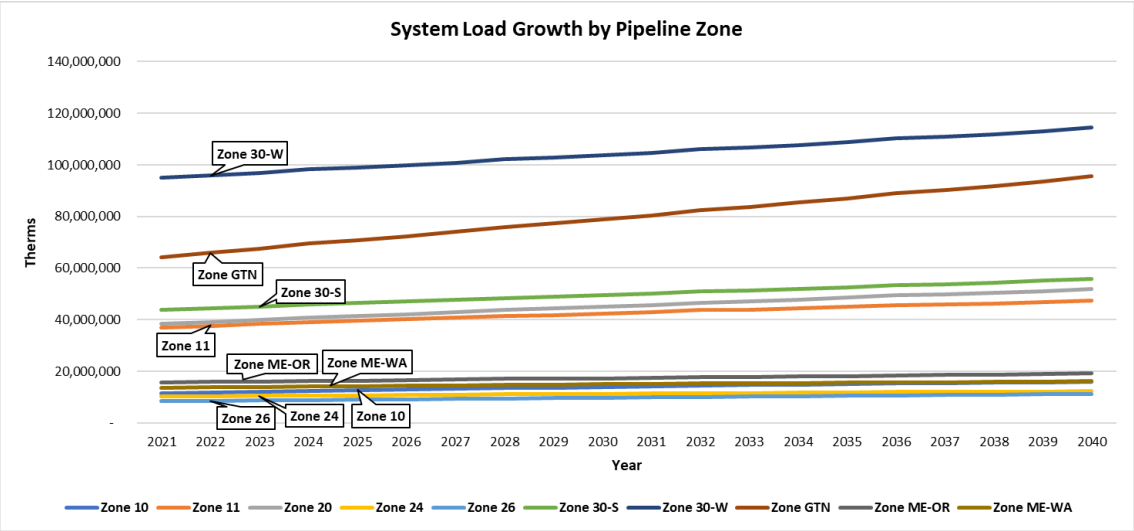
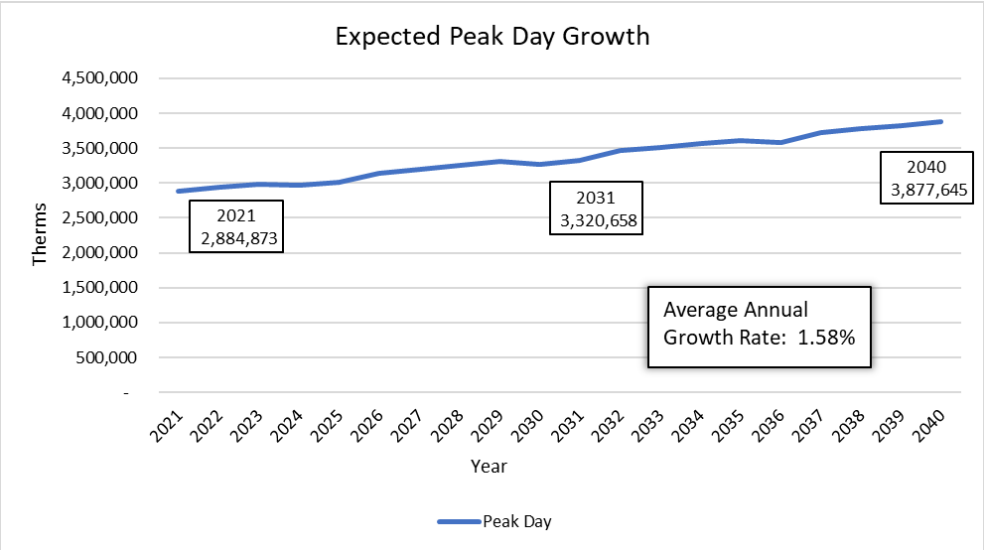


Figure 3-14: System 20-Year Average Load Growth by Pipeline Zone

Zone	Load Growth		Zone	Load Growth
Zone 10	1.75%		Zone 30-S	1.28%
Zone 11	1.30%		Zone 30-W	0.98%
Zone 20	1.61%		Zone GTN	2.12%
Zone 24	1.01%		Zone ME-OR	1.06%
Zone 26	1.58%		Zone ME-WA	0.90%

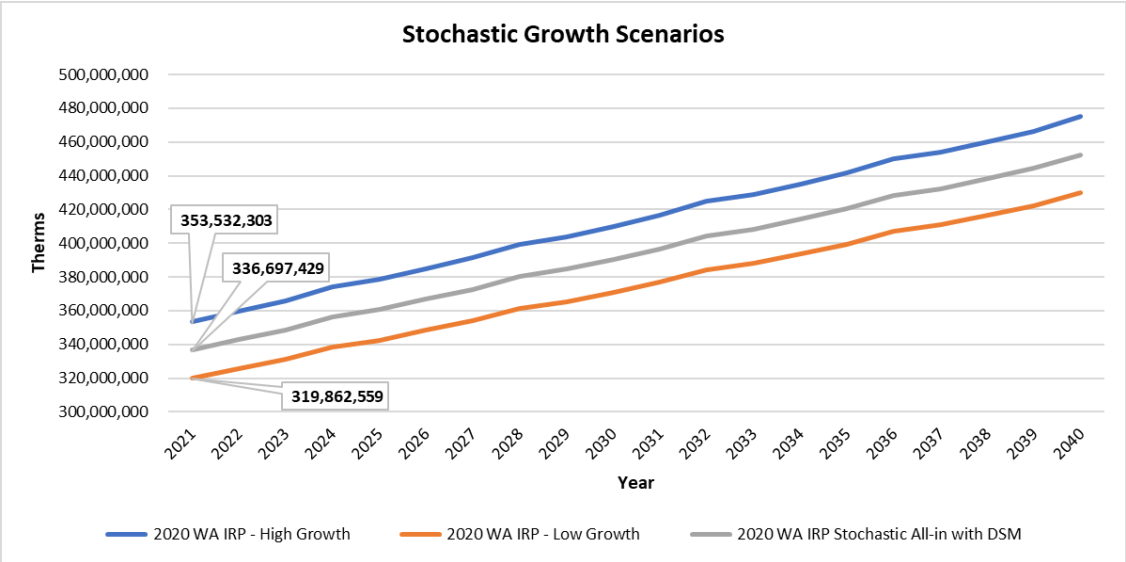
Figure 3-15: Expected System Peak Day Growth (Volumes in Therms)



High and Low Growth Scenarios

In previous IRPs, the high and low growth scenarios were built from the deterministic As-is portfolio. Cascade has moved to using the All-in portfolio as a means to compare low and high growth scenarios because Cascade believes it provides a more realistic view. There are two primary components of the growth scenarios. The first component involves varying the inputs to the model. These inputs are derived from the confidence intervals of the customer growth forecast, which were approximately 5%. The second component, new to this IRP, involves a stochastic element. This component uses stochastic weather (99th percentile) and stochastic price (95th percentile). By using both varied inputs as well as stochastic elements, Cascade can be more confident in the high and low growth scenarios. Figure 3-16 displays the stochastic total system load growth across the various stochastic scenarios.

Figure 3-16: Stochastic Total System Load Growth Across Scenarios



Load growth under the low stochastic scenario is showing approximately 17 million less therms per year while load growth under the high stochastic scenario is showing approximately 17 million more therms per year than the stochastic All-in scenario. By using Monte Carlo simulations and pulling the 99th percentile weather draw and 95th percentile price draw, Cascade can assert with a high degree of certainty that these scenarios accurately encompass a potential range of load growth scenarios. Figure 3-17 shows the values for stochastic growth scenarios.

Figure 3-17: Stochastic Total System Load Growth Across Scenarios in Therms

Year	Low	All-in + DSM	High
2021	319,862,559	336,697,429	353,532,303
2026	348,371,062	366,706,384	385,041,701
2031	376,770,704	396,600,742	416,430,775
2036	410,741,648	432,359,627	453,977,608
2040	429,748,623	452,366,973	474,985,319

Non-Core Outlook

Unlike the core, non-core (or transportation) customers are customers who schedule and purchase their own gas, generally through a marketer, to get gas to the citygate. The customer then uses Cascade's distribution system to receive the gas. Cascade has approximately 247 transportation customers, with six of those customers being electric generation customers. In both Washington and Oregon, the 2021 forecast for non-electric generation customers is approximately 581

million therms and the electric generation customers is about 417 million therms for a total of 998 million therms for the transportation customers.

Cross-Validation

Cascade continues to evolve and improve its forecasting methodologies. For this IRP, Cascade performed some model validation analysis, called cross-validation, in order to validate the assumptions going into the models as well as the results coming out. This process is time intensive, so Cascade picked a couple citygates to perform this analysis on. There are many ways to cross-validate a forecasting model such as hold-out validation, k-fold validation, and bootstrap validation. Each technique has its pros/cons when it comes to strength of validation and computational time. Cascade chose the hold-out method as it contains the best combination of having strong validation results with low computation time in reference to the other methodologies. The steps of the hold-out method involve selecting a specific citygate and rate class, limiting the historical data, developing a model using the same methodology as the original model, and then comparing the forecasted results to real world data. Cascade chose one of its more volatile citygates, Sumas SPE Loop, and one of its more stable citygates, Yakima Loop, in order to maximize the value of the cross-validation results. Figure 3-18 and Figure 3-19 show both these citygates' actual pipeline flow data compared to a forecast of a model made from only 2015 and 2016 data.

Figure 3-18: Sumas SPE Loop Cross-Validation

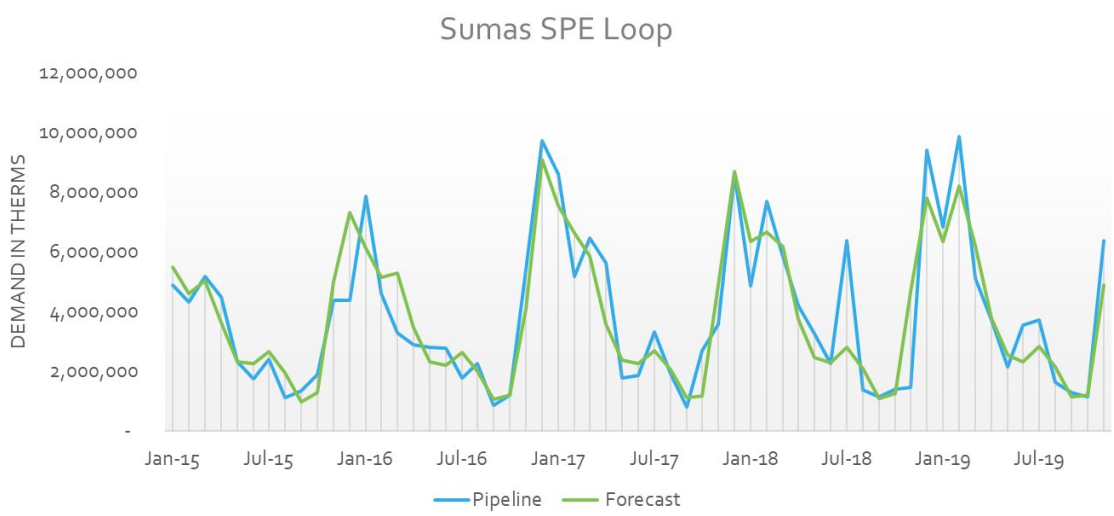
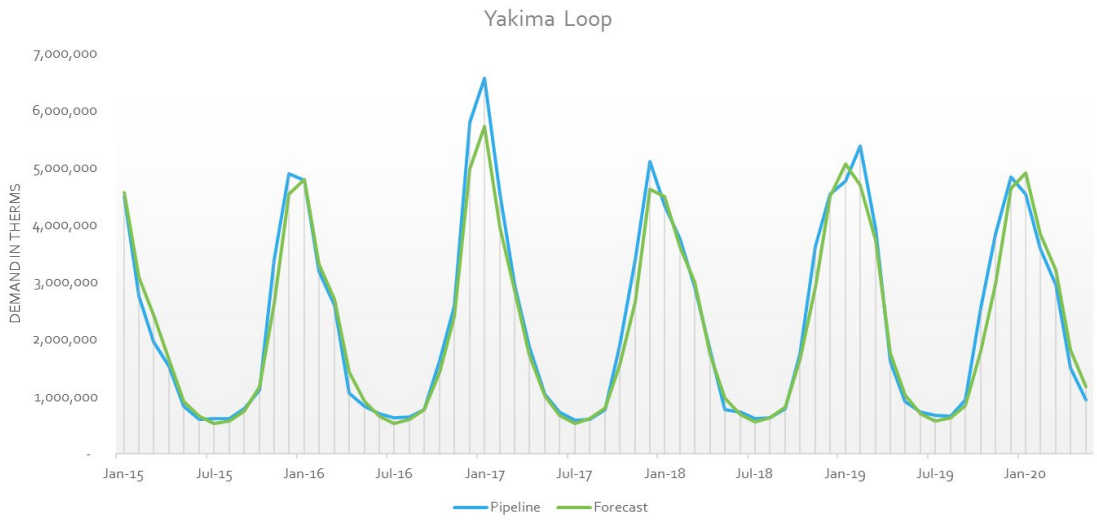


Figure 3-19: Yakima Loop Cross-Validation



Cascade will continue to perform cross-validation and will investigate ways to make this process more efficient in order to validate more models, more often.

Alternative Forecasting Methodologies

Cascade's forecasting methodologies used in the customer forecast and the UPC forecast have remained consistent. Cascade continues to utilize Fourier terms and ARIMA terms in its forecasting methods. Cascade utilizes R as its primary statistical analysis software and uses models that follow a dynamic regression methodology. The Company plans to continue improving the customer and demand forecast model through R to enhance the process' efficiency.

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

- A desire for precision and a high degree of accuracy;
- A universal understanding that forecasts should mirror future realities but may have unanticipated swings in either direction;
- A disconnect between planning and operational functions, in that natural gas purchasing and dispatch will be based on immediate needs which, in actuality, are guaranteed to vary from the plan (per the previous bullet);
- An understanding that an increased cost of improved precision sometimes has decreasing customer benefits;
- A need to meet regulators' expectation that the Company show continual improvement because new tools are available. For example, the concept of "adaptive management" can be applied;

- The major differences in accounting treatment between the states regarding test years for ratemaking purposes (that is, for general rate case filings) and not necessarily for planning. At this time, Oregon uses future test year accounting while Washington employs a historic test year;
- The fuzziness of historic data that includes effects of energy efficiency, retail price (from annual PGA—purchased gas adjustment—changes and other rate changes), sometimes abnormal weather, new technology, and then-unique economic conditions (e.g., recession, interest rates, etc.). Cascade uses actual historic data. The term fuzziness is used in the context of basing forecasts on past-period data that includes many variables, any one of which may have increased or decreased in the intervening time between historical occurrence and forecasted periods. This causes difficulty for utilities trying to isolate primary factors for greater precision of long-term calculations.
- Unknown and uncertain future changes such as the assumptions around carbon policy and other environmental externalities; and
- A need to demonstrate support for assumptions such as growth in customers, use per customer and changes from previous forecasts, type of use (i.e., heating, manufacturing, etc.), to name a few.

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

Uncertainties

This forecast represents Cascade's best estimate about future events. At this time, several important factors make predicting future demand particularly difficult – continued economic growth, carbon legislation, building code changes, direct use campaigns, energy efficiency, and long-term weather patterns. The range of scenarios presented here and in Chapter 10 encompass the full range of possibilities through econometric analysis. These forecasts were created after running through a matrix of different functional forms and economic indicators. The chosen indicators were selected because of their consistency in returning statistically valid results. While they may be the best results mathematically, they are not the sole and only determinants of demand. As a result, while Cascade believes that the numbers presented here are accurate and that the scenarios presented represent the full range of possibilities, there are and always will be uncertainties in forecasting future periods.

Chapter 4

Supply Side Resources

Overview

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

This chapter describes the various gas supply resources, storage delivery services from Jackson Prairie underground storage and Plymouth liquified natural gas (LNG) service, and transportation resource options available to the Company as supply side resources.

Key Points

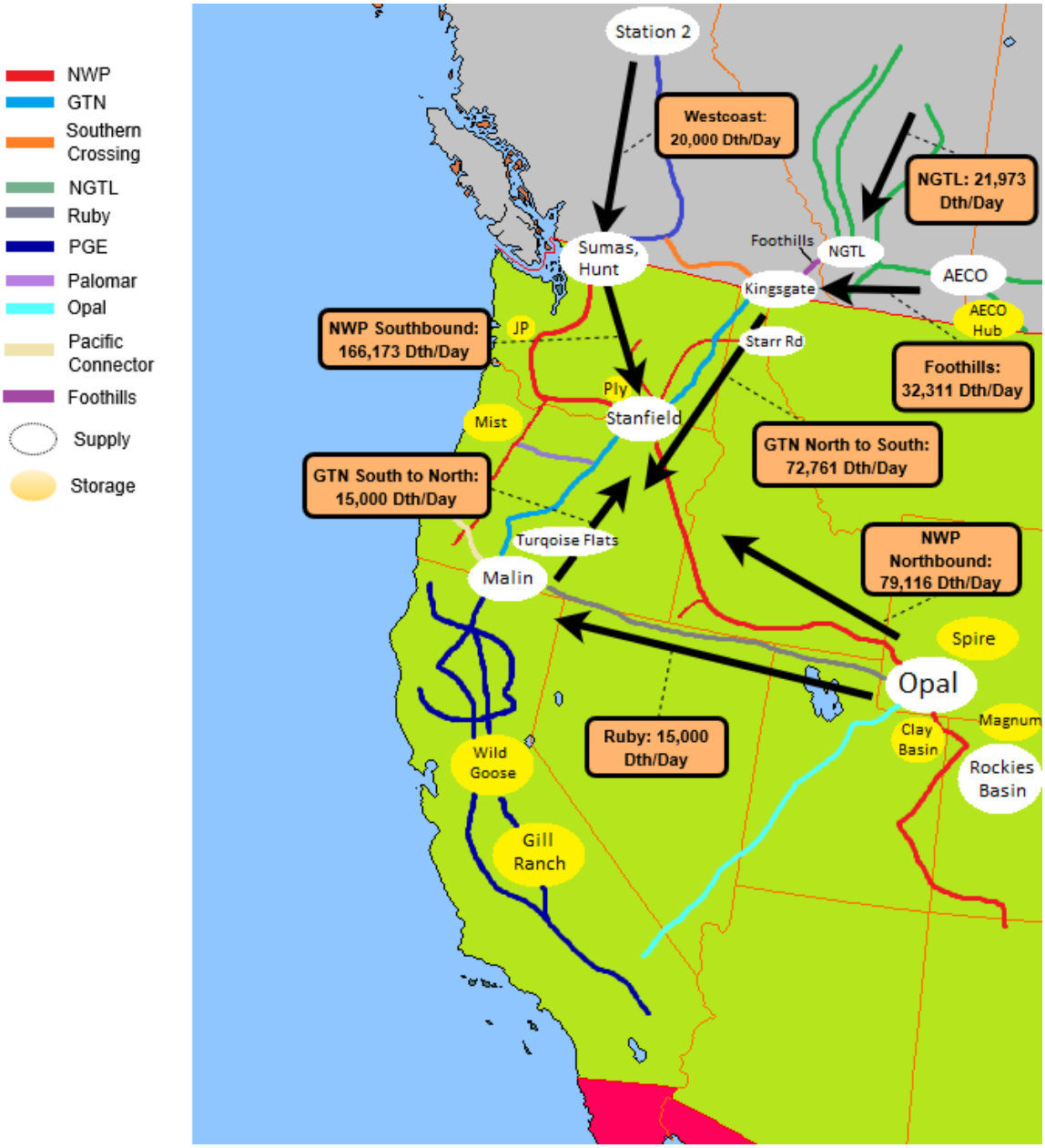
- To meet the Company's core market demand, Cascade accesses firm gas supplies and short-term gas supplies purchased on the open market, in addition to utilizing storage.
- Cascade purchases gas from the Rockies, British Columbia (Sumas), and Alberta (AECO). Gas is transported to the Company's system via pipelines by either bundled or unbundled contracts.
- The long-term planning price forecast is based on a blend of futures market pricing along with long-term fundamental price forecasts from multiple sources.
- The Company identifies potential incremental supply resources for the 2020 IRP.
- Risk management policies are implemented to promote price stability.
- Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply purchasing strategy.
- Modeling of Cascade's available resources results in the lowest reasonably priced optimum portfolio.

Gas Supply Resources

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

Cascade's gas supply portfolio is sourced from three basic areas of North America: British Columbia, Alberta, and the Rockies. Figure 4-1 provides a general overview of regional gas flows to Cascade's distribution system.[1]

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



[1] This map does not reflect three contracts Cascade anticipates to acquire November 1st, 2023: GTN North to South of 10,000 dth/day, 20,000 dth/day on NGTL, and 10,000 dth/day on Foothills.

Firm Supply Contracts

Firm supply contracts commit both the seller and the buyer to deliver and take gas on a firm basis, except during *force majeure* conditions. From Cascade's perspective, the most important consideration is the seller's contractual commitment to make gas available day in and day out regardless of market conditions. Firm supplies are a necessary component of Cascade's core market portfolio given its obligation to serve and the lack of easily obtainable alternatives for customers during periods of peak demand. Firm supply contracts can provide base load services, seasonal load increases during winter months, or they can be used to meet daily peaking requirements. Quantities vary, depending on the need and length of the contract. Operational considerations regarding available upstream pipeline transportation capacity and any known constraints must also be considered. Base load contracts can range from as small as 500 dths/day to quantities in excess of 10,000 dths/day. Blocks of 1,000, 2,500, 5,000 and 10,000 dths/day are standard as these are the most operationally and financially viable blocks for suppliers.

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

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

Supply contract terms for firm commodity supplies vary greatly. Some contracts specify fixed prices, while others are based on indices that float from month to month. Most contain penalty provisions for failure to take the minimum supply identified in the North American Energy Standards Board (NAESB) contract terms. Contract details will also vary for each individual supplier's needs and the NAESB contract special addendums.

Gas that is purchased for a short period of time (one to thirty days) when neither the seller nor the buyer has a longer-term firm commitment to deliver or take the gas is referred to as a spot market purchase. Spot market supplies differ from firm

resources in that they are more volatile, both in terms of availability and price, and are largely influenced by the laws of supply and demand.

In general, spot market supplies (also called day gas) are provided from gas supplies not under any long-term firm contract. Therefore, as firm market demand decreases, more gas becomes available for the spot market. Prices for spot market supplies are market driven and may be either lower or higher than prices under firm supply contracts. In warmer weather, as firm market demand requirements decrease, usually more gas becomes available for the spot market, resulting in lower prices. In colder weather, as firm markets demand their gas supplies, the remaining spot market supplies can carry higher prices.

The role for spot market gas supply in the core market portfolio is based on 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. Depending upon availability and price, spot market volumes may be used in place of storage withdrawal volumes to meet firm requirements on a given day or for mid-heating season refills of storage inventory during periods of moderate weather.

Storage Resources

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

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

Depending upon the location of the storage facility, pipeline transportation may also be required to move the gas from the facility to the distribution system. Storage facilities located within the Company's distribution system or on the immediately upstream interstate pipeline are preferable to those located off-system. Off-system storage requires additional upstream pipeline transportation and may limit the flexibility of the resource. Cascade does not own any storage facilities and, therefore,

must contract with storage owners to lease a portion of those owners' unused storage capacity. Figure 4-1 on page 4-3 displays the location of some of the storage facilities in the region.

Cascade has contracted for storage service directly from NWP since 1994. Jackson Prairie is located in Lewis County, Washington, approximately ten miles south of Chehalis. The following paragraph explaining the Jackson Prairie facility is found on Puget Sound Energy's website.[2] Puget is a one-third owner of the Jackson Prairie facility.

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

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

In addition to the other storage facilities, the Company leases storage capacity from Mist. The Mist facility is located near Mist, Oregon and is adjacent to Northwest Natural Gas' distribution system and has a direct connection to NWP for withdrawals and injections. The Mist facility is owned and operated by Northwest Natural Gas. Cascade has 600,000 dth of leased capacity.

Both the Jackson Prairie and the Plymouth facilities are located directly on NWP's transmission system, while Mist Storage is located on the Northwest Natural Gas system that is connected to NWP via two different citygates Therefore, storage withdrawal rates can be changed several times during an individual gas day to accommodate weather driven changes in core customer requirements. This type of operating flexibility would not necessarily be available with off-system storage. Withdrawal capabilities must also be accompanied by firm capacity on the transporting pipeline(s) to be of any value as a reliable source of gas supply. Cascade's Jackson Prairie storage and Plymouth LNG service require TF-2 firm transportation service for storage withdrawals; Cascade has sufficient firm TF-2

[2] *See:* Jackson Prairie Underground Natural Gas Storage Facility, https://www.pse.com/pages/energy-supply/natural-gas-storage, as of February 2, 2021.

service to meet its storage daily deliverability levels. The Company's contracted storage services are summarized in Figure 4-2.

Figure 4-2: Cascade Leased Storage Services (Volumes in Therms)

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

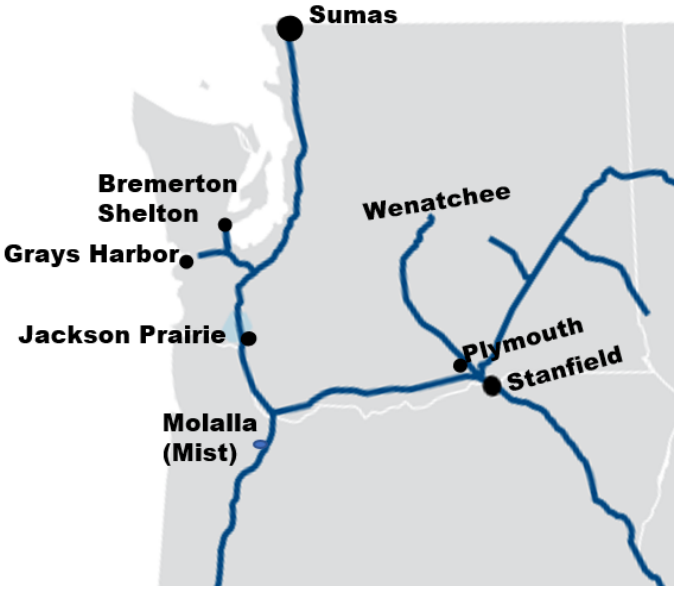
Capacity Resources

Capacity options are either interstate pipeline transportation resources or capacity on Cascade's local distribution system. Cascade's local distribution system is built to serve the entire connected load in its various distribution service areas on a coincidental demand basis, dependent upon the type of service the customer has contracted to receive.

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

Cascade has over 30 long-term annual contracts with NWP, numerous long-term annual and winter-only transportation contracts with GTN (including the upstream capacity on TransCanada Pipeline's Foothills and Alberta systems), a long-term, winter-only contract with Ruby Pipeline, and one long-term annual contract with Enbridge (Westcoast Transmission) in British Columbia, Canada. These contracts do not include storage or other peaking services that may provide additional delivery capability rights. Figure 4-1 on page 4-3 provides a general flow of Cascade's combined contracted pipeline transportation rights.

Bremerton-Shelton Realignment Package



In the 2018 WA IRP Cascade indicated the Company was considering a proposed capacity realignment to firm up Cascade's long-term rights on the Bremerton Lateral. NWP had presented Cascade with a proposal to realign a portion of the Company's transportation capacity that runs from Sumas to eastern portions of Washington and Oregon. Part of the proposal required a series of amendments to existing pipeline capacity in addition to acquiring incremental capacity to address the projected shortfalls along the I-5 corridor. Cascade agreed to the realignment package on June 14, 2019. A summary of the major components of this package follows.

Cascade acquired an incremental 10,000 dth/d of NWP capacity via a hydraulic exchange. Through a series of releases and amendments, this 10,000 dth/d addressed the I-5 shortfall identified in the 2018 IRP. The Bremerton/Shelton realignment firmed up Cascade's primary rights through the Tumwater Compressor station, which supports the Bremerton/Shelton lateral. Cascade was able to increase an existing discounted storage redelivery capacity agreement from 8,960 to 10,000 dth/d. The rate for the modified redelivery agreement is at a fraction of NWP's year-round transportation rates.

To offset the incremental costs of the 10,000 dths gained from the hydraulic exchange, Cascade released the incremental capacity at max rate to a third party for the first ten years.

The package also gave Cascade the opportunity to segment 20,000 dth/d of existing capacity to generate 20,000 of capacity to move Mist storage on NWP's system. Cascade created two segments from our main NWP capacity agreement 100002 using a full transportation path from Sumas to eastern Washington and Oregon through October 31, 2032, at no incremental cost to Cascade:

- The first segment is 20,000 dths/d from Sumas to Shelton lateral and Jackson Prairie
- The second segment is 20,000 dths/d from Jackson Prairie to eastern WA/OR (retained by Cascade)

- In order to provide upstream capacity to move Mist storage, the Company amended the second segment to change the receipt point from Jackson Prairie to Molalla (Mist) through March 31, 2024.
- On April 1, 2024 the receipt point reverts back to Jackson Prairie for the remainder of the term.

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

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

- Annual supply package;
- November through March (the whole heating season);
- December through February (peak of the heating season);
- Spring Season (Apr-Jun);
- Spring/Summer Season (April through October);
- Day Gas; and
- No more than 25% of the overall portfolio can be supplied by a single party.

Natural Gas Price Forecast

For IRP purposes, the Company develops a baseline, high, and low natural gas price forecast. Demand, oil price volatility, the global economy, electric generation, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. Cascade is closely monitoring the market for long term impacts of COVID-19. Cascade did reach out to its hedging consultant, Gelber & Associates, who provided the following analysis in the Company's 2020 Hedge Plan 'There has been a precipitous fall in oil prices early this year after a supply glut formed from the expected economic impacts of the COVID-19 outbreak and a nascent crude oil price war between Saudi Arabia and Russia. These items are both bullish for natural gas prices. This pricing relationship may be counterintuitive but approximately 15% of natural gas is produced as "associated gas". Associated gas is gas which is a direct result of crude oil production.

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

following discussion provides an overview of the development of the baseline forecasts.

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

Cascade believes that relying on a single source for developing the Company's 20-year price forecast is not the most reasonable approach. Some sources such as EIA and Wood Mackenzie produce Henry Hub pricing over the long-term; whereas other sources like the NYMEX basis (e.g., Sumas) provide price indicators over a shorter period of time. Additionally, price forecast sources produce their forecasts or indicators at varying points in time throughout the year. Finally, most forecasts are at an annual level versus a monthly level. In order to capture the potential seasonality as well as the variances of monthly price within the producing basins, the Company blends the pricing data from these various forecast sources.

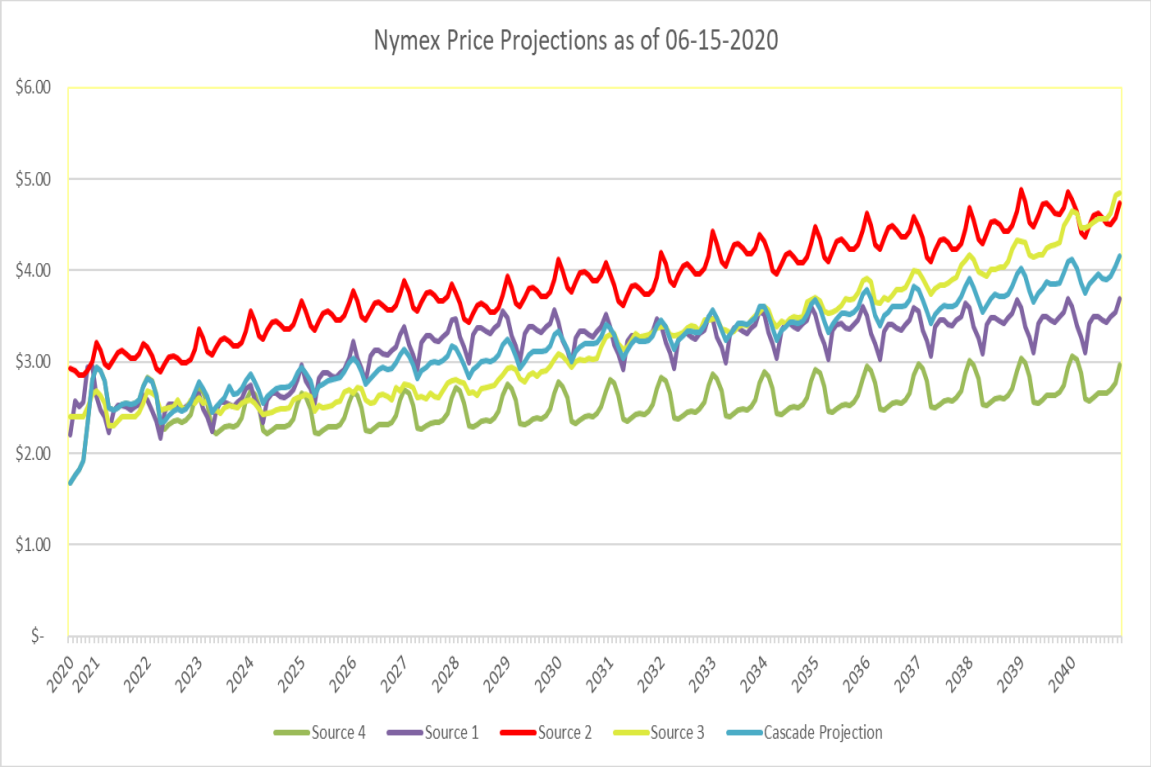
The fundamental forecasts of Wood Mackenzie, the EIA, NWPCC, Platts, S&P Global, and Cascade's trading partners are resources for the development of a blended long-range price forecast. Wood Mackenzie publishes a long-term price forecast twice a year to subscribing customers. This forecast was broken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

With a monthly Henry Hub price determined from the above sources, the Company assigned a weight to each source to develop the monthly Henry Hub price forecast for the 20-year planning horizon. These weights were derived by calculating the Symmetric Mean Absolute Percentage Error (SMAPE) of each source versus actual Henry Hub pricing since 2010. The inverse of these error terms was then used to determine the weight given to each source. A sample of the forecast weighting factors are shown in Figure 4-3. A comparison of the sources Cascade uses in its forecast and the actual blended forecast is provided in Figure 4-4. Cascade's price forecast was locked in on June 15, 2020.

Figure 4-3: Sample of Cascade's Henry Hub Price Forecast Weights

Date	Source 1	Source 2	Source 3	Source 4
T+1	9.115%	47.371%	29.499%	14.015%
T+2	10.772%	44.692%	29.580%	14.955%
T+3	9.570%	49.212%	28.405%	12.812%
T+4	12.002%	43.537%	30.386%	14.075%
T+5	11.523%	43.476%	32.206%	12.796%
T+6	14.850%	32.243%	37.449%	15.458%
T+7	13.972%	35.110%	36.448%	14.470%
T+8	15.837%	31.029%	37.275%	15.859%
T+9	15.074%	35.022%	34.192%	15.712%
T+10	16.913%	31.090%	34.166%	17.831%
T+11	16.168%	34.193%	31.641%	17.999%
T+12	17.183%	29.466%	32.449%	20.902%

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



Age-Dampening Mechanism

To ensure that the forecast is accounting for the most current information in the market, Cascade has introduced an age dampening mechanism to its price forecast. Every month, if there is a source that is over one year old, all sources' weights are reduced by their share of the total number of months that all sources are outdated by. For example, if Source 1's forecast was fifteen months old, Source 2's was seven months old, and Source 3's was two months old, then each of these sources would be reduced by 15/24, 7/24, and 2/24 respectively. The detracted weights are then added back into the weight of the forwards market since that will always be the most current source (as it is updated daily). The one-year threshold was chosen qualitatively, as this methodology could be too punishing if all sources were not that old. For example, if one source was two months old, another was one month old, and another brand new, the first source would lose 66% of its weight to the forward curve, even though it still contains relatively current information regarding the market.

Cascade weights the futures market at 100% for the first fifteen months of the forecasting period. The weights are then linearly interpolated over the next two years in order to align them with the calculated weights as described above.

The Company recognizes the importance of verifying forecast accuracy periodically and as such, will perform routine cross-validation to evaluate the impact of any modifications to the price forecast.

Development of the Basis Differential for Sumas, AECO and Rockies

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

Pros and Cons of Methodology Changes

The changes made to the 2018 IRP that carried over to the 2020 price forecast represent a continual methodological improvement over the forecasts in previous IRPs. Using the daily NYMEX forwards for short term forecasting allow the Company's forecast to incorporate current market data, such as weather and *force majeure* events, into its projections. Additionally, the age dampening mechanism favors sources that have been updated more recently, which better captures a paradigm shift in the markets on a long-term basis versus a forecast that may be a few months or even years old. Finally, the use of SMAPE to assign weights to the sources creates a more scientific rationale for the blending of forecasts.

While Cascade is pleased with this forecast, there are always areas of potential improvement. Since the forecast is a blending of other forecasts, the Company relies on the accuracy of its sources. While the SMAPE calculation helps to reward the more accurate forecasts, if all sources failed to capture a major market movement, Cascade's forecast would ultimately end up inaccurate as well. Additionally, some sources produce fairly infrequent forecasts, creating a small sample size for them to be evaluated in the SMAPE calculation. The Company is monitoring these problems to ensure they do not skew the forecast and has mechanisms in place to allow for a manual adjustment if market intelligence deems such a modification to be appropriate.

Incremental Supply Side Resource Options

As is more thoroughly described in Chapter 10, Resource Integration, some of the load growth over the planning horizon may require Cascade to secure incremental supply side resources. The purpose of this section is to identify the potential incremental supply resources the Company considered for the current IRP.

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

Pipeline Capacity

- **Cross-Cascades, Trail West (Palomar, NMax, Sunstone, Blue Bridge, et al):** Trail West is a proposed pipeline starting at GTN's system near Madras, Oregon, and connecting NWP's Grants Pass Lateral near Molalla, Oregon. Since portions of the Company's distribution system are not connected to Molalla, incremental pipeline capacity would be needed to transport gas northbound to certain load centers. NWP has proposed a transport service that would bundle Trail West capacity with NW Natural's northbound Grants Pass Lateral capacity. From Cascade's perspective, this might present an alternative means to move Rockies gas to the I-5 corridor. At this time, there has been no new activity associated with this project. The development of this project would likely have a two to three year lead time.

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

- **NWP Eastern Oregon Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 24 and Zone ME-OR. Examples of the Cascade service areas that would benefit from this project are Pendleton and Baker City. Similar to a proposed NWP Wenatchee expansion, it would be relatively small scale and could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **NWP Express Project/I-5 Sumas Expansion Project (Regional or Cascade Specific Project):** Cascade envisions this project as expanding capacity from Sumas on a potential NWP project that is the successor to the Western Expansion project. It would potentially combine Cascade's infrastructure expansion needs with other regional requests from parties such as local distribution companies (LDCs), power generators, and large petrochemical projects. The scale of this project is larger, potentially resulting in a more favorable unit cost; although with scale and multiple parties involved, timing for in-service dates may vary by the various participants. Examples of the Cascade service areas that would benefit from this project are Bellingham, Mount Vernon, Bremerton, and Longview. Cascade, through the Company's active membership in various industry task forces and associations, works with regional pipelines and LDCs to consider potential pipeline expansions. The development of this project would likely have a three or four year lead time.

As of this writing, there hasn't been any new activity associated with the potential project.

- **NWP Wenatchee Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point (e.g. Sumas) that is designed to serve load growth needs in Zone 10 and Zone 11. Examples of the Cascade service areas that would benefit from this project are Yakima and Wenatchee. Accordingly, it would have a relatively small scale and so could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **NWP Zone 20 Expansion:** This alternative resource would be incremental NWP capacity from a Washington State receipt point that is designed to serve load growth needs in Zone 20. Examples of the Cascade service areas that would benefit from this project are Kennewick and Moses Lake. Similar to a proposed NWP Wenatchee expansion, it would have a relatively small scale and so could be expected to have a relatively high unit cost. The development of this project would likely have a three or four year lead time. As of this writing, there hasn't been any new activity associated with the potential project.

- **Pacific Connector:** The Pacific Connector Pipeline project is tied to the development of the Jordan Cove LNG export terminal in Coos Bay, Oregon. This pipeline would start near Malin, Oregon, and would cross NWP's Grants Pass Lateral (GPL) in the vicinity of Roseburg, Oregon. This project presents an opportunity as a potential supply resource for this IRP. Cascade would not be seeking to become a shipper on Pacific Connector. The Company views this project as a bundled pipeline supply service from Malin to the Company's citygates. The project was initially denied due to lack of demand, which has since increased, but faces considerable opposition including but not limited to landowners, activists, and protesters. Incremental transport involving GTN might be necessary to ensure transport from Malin to Cascade's GTN receipt point at Turquoise Flats. On January 19, 2021 federal regulators upheld Oregon's decision to deny a water quality certification for Jordan Cove and Pacific Connector.[3] This latest event has led to some concern the project may not proceed.

- **Southern Crossing Expansion:** FortisBC Southern Crossing is considering an addition of 300-400 MMcf/d of bidirectional capacity. FortisBC has proposed a reinforcement project for the Southern Crossing

[3] *See* https://www.oregonlive.com/politics/2021/01/federal-regulators-deliver-potentially-fatal-blow-to-jordan-cove.html

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

Storage Opportunities

- **AECO Hub Storage:** This is Niska's commercial natural gas storage business in Alberta, Canada. The service is comprised of two gas storage facilities: Suffield (South-eastern Alberta) and Countess (South-central Alberta). Although the two AECO facilities are geographically separated across Alberta, the toll design of the Nova Gas Transmission Ltd. (NGTL) system means they are both at the same commercial point. Capacity at one of the facilities is possible as an alternative resource. However, some services are available for limited periods of time but are subject to possible interruption. Incremental transport involving NGTL, Foothills, GTN, and possibly NWP would also be necessary.

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

- **Mist Storage:** This facility is located near Mist, Oregon and is adjacent to NW Natural Gas' distribution system and has a direct connection to NWP for withdrawals and injections. The Mist facility is owned and operated by NW Natural Gas**.** NW Natural's 2018 IRP (LC71), Chapter 9, Section 9.2.1 indicates that "Mist storage capacity is currently reserved for the core market… NW Natural has developed additional capacity in advance of core customer need. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire."

In the past several years NW Natural has held a Mist open season in 2017, followed by two Mist RFPs. Cascade became a Mist ISS customer for the first time in May 2019. The Company leases 600,000 dths of storage capacity. This lease is set to expire in 2024.

On January 14, 2021 NW Natural sent their latest RFP to Cascade with bids due by January 29, 2021. With assistance in modeling from Cascade's asset manager, Tenaska Marketing, Cascade's GSOC authorized Cascade to submit a bid at 76% of the maximum rate (for reference, the current Mist agreement is at 100% of the maximum rate). Cascade was awarded 540,000 dths of additional Mist capacity on February 1, 2021. The term of this additional Mist service is May 1, 2021 through April 30, 2026. Please note that as of this writing, this second Mist is still in the final contracting stage and technically is not yet part of the portfolio.

As the Company states throughout, the IRP is developed at a point in time. Unfortunately, Cascade had no advanced knowledge of the 2021 Mist RFP during the development of this IRP. Therefore, this latest Mist leased storage is not included in the IRP analysis. It is important to note that Cascade does not own any storage. In addition to the currently leased Mist storage, the Company leases storage at Jackson Prairie and Plymouth LNG. Given the Company's wide geographical and noncontiguous service territory, storage has a unique role in daily upstream operations compared to other regional LDCs. For Cascade, storage functions primarily as an operational tool for balancing and upstream pipeline operational flow orders as opposed to use primarily for price arbitrage. Also, Cascade continues to have the lowest ratio of customers to storage capacity in comparison to other regional LDCs. The addition of this second Mist account improves the Company's portfolio flexibility with minimal impact to customer rates.

- **Spire (formerly Ryckman Creek) Storage:** As of December 2017, Ryckman Creek, LLC operates as a subsidiary of Spire Inc. Spire Gas Storage Facility is located near the town of Evanston, Wyoming and approximately twenty-five miles southwest of the Opal Hub. Spire Storage has converted a partially depleted oil and gas reservoir into a gas storage facility with 35 BCF of working gas and a maximum daily withdrawal rate of 480,000 Dths/d. Spire Storage currently has interconnects with Questar Gas Pipeline, Kern River Transmission, Questar Overthrust Pipeline, Ruby Pipeline, and NWP. Incremental transport involving Questar and possibly Ruby would be necessary.

- **Wild Goose Storage:** Wild Goose is located north of Sacramento in northern California and is the first independent storage facility built in the

state. The facility commenced full commercial operations in April 1999 and in April 2004 completed its first expansion. Storage from this facility would require California Gas Transmission (CGT) transport, which has a potentially cost-prohibitive demand charge of $1.68/Dth. Incremental transport involving GTN would also be necessary.

- **Magnum Gas Storage:** Magnum is currently developing the Magnum Gas Storage facility at the Western Energy Hub. Magnum Gas Storage will be the first high-deliverability storage facility in the Rocky Mountain Region. The facility will contain four solution mined storage caverns capable of storing 54 billion cubic feet (Bcf) of natural gas.[4] Magnum would be connected to the Kern River Gas Transmission and Questar Pipeline systems at Goshen, Utah. Incremental transport involving Questar and possibly Ruby would be necessary.

- **Clay Basin:** Clay Basin is located in Northeast Utah and is a 54 Bcf working gas storage facility. Clay Basin is connected to the Questar Pipeline system. Incremental transport involving Questar and possibly Ruby would be necessary.

Other Alternative Gas Supply Resources

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

- **Renewable Natural Gas (RNG):** Cascade is committed to the acquisition of cost-effective RNG under the current regulatory guidance provided by the OPUC and WUTC. An in-depth discussion of Cascade's RNG

[4] *See* https://www.wyopipeline.com/magnum-gas-storage-llc-western-energy-hub-project/

philosophy and analysis techniques can be found in Chapter 8, Renewable Natural Gas.

- **Additional transportation realignments:** The Company's geographically widespread service territory gives Cascade great flexibility to utilize 316,994 Dths/day of delivery rights vs 205,123 Dths/day of receipt rights. Cascade has the right to deliver gas to any delivery point within Washington and Oregon so long as the total MDDOs are not exceeded. Cascade and NWP have worked continuously in recent years for ways to address Cascade's potential peak day capacity shortfalls through re-alignment of the Company's contractual rights where possible, which mitigates the need to acquire incremental NWP capacity through expansions.

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

Supply Side Uncertainties

Several uncertainties exist in evaluating supply side resources. These include regulatory risks, deliverability risks, and price risks. Regulatory risks include the unknown impacts of future Federal Energy Regulatory Commission (FERC) or Canada's Energy Regulator (CER)[5] rulings that may impact the availability and cost of interstate pipeline transportation.

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

[5] The Canada Energy Regulator (CER) is the agency of the Government of Canada under its Natural Resources Canada portfolio, which licenses, supervises, regulates, and enforces all applicable Canadian laws as regards to interprovincial and international oil, gas, and electric utilities. The agency came into being on August 28, 2019, under the provision of the Canada Energy Regulator Act of the Parliament of Canada superseding the National Energy Board from which it took over responsibilities.

As the United States continues to search for environmentally friendly, economically viable options to displace gasoline and coal, natural gas is seen as a fuel that could be a viable resource in a greener future. It is worth noting that some planned and proposed projects could have a direct impact on the availability of supply or at least may pose potential risks to increasing the price of supplies sourced from British Columbia and Alberta. For example, Coastal GasLink Pipeline is currently under construction. Coastal GasLink, once completed in 2023, will transport natural gas from northeast British Columbia to an LNG export facility near Kitimat BC near the Pacific coast. Shippers using this pipeline will likely lead to increased competition for gas supplies in the region. Also, proposed expansions on the TransCanada pipelines in 2022 and 2023 may also increase competition for available gas supplies in Alberta and British Columbia. The Company will continue to monitor and be actively involved in the various pipeline forums as these initiatives develop.

Financial Derivatives and Risk Management

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

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

In a swap, parties agree to exchange an index price for a fixed price over a defined period. In this scenario, Cascade would be able to provide its customers with a fixed price over the duration of the swap period. In theory, the price would be levelized over the long-term. Futures and swaps are typically called costless collars.

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

to the underlying futures price, the period of time before the option expires, and the volatility of the futures contract.

Cascade's Gas Supply Oversight Committee (GSOC) oversees the Company's gas supply hedging strategy. The Company's current gas hedging strategy is outlined below:

Hedged Fixed-Price Physical or Financial Swap Targets

- Year one target set at 50% of annual requirements.
- Year two target set at 30% of annual requirements.
- Year three target set at 10% of annual requirements.

Depending on market conditions, the strategy allows for the ratchets to increase to 60%, 40%, and 20%, respectively, provided current market information supports moving to a different level.

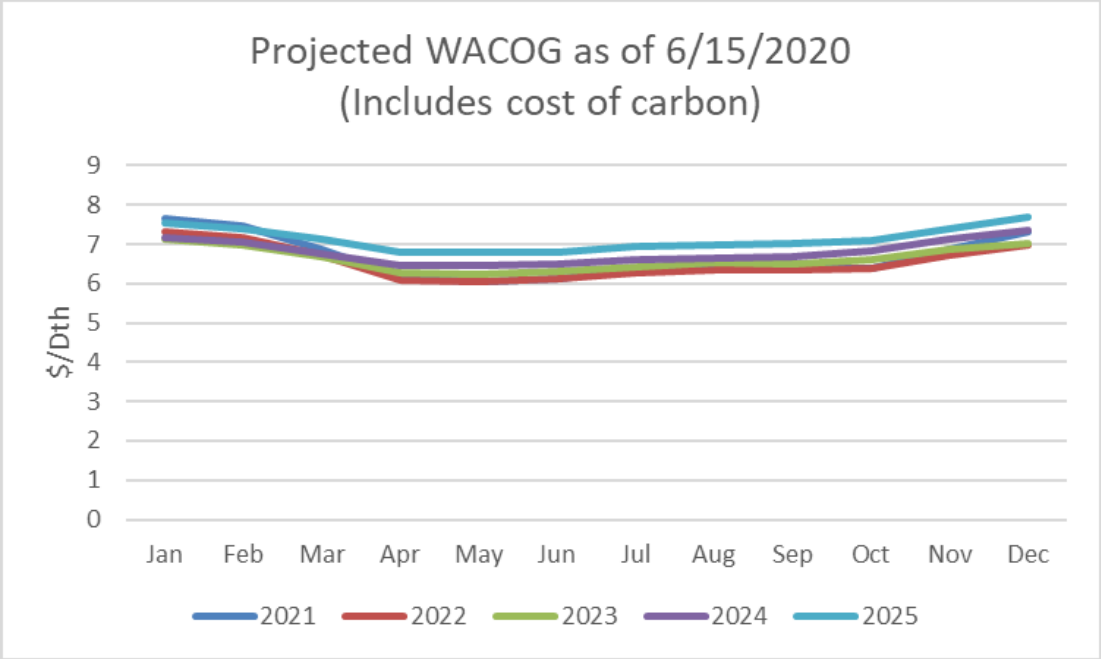
Cascade employs prudent risk management strategies within designated parameters to minimize the risk of operating losses or assumption of liabilities from commodity price increases because the price the Company pays for gas is subject to market conditions. Risk is associated with business objectives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

The use of derivatives is permitted only after identified risks have been determined to exceed defined tolerance levels and are considered unavoidable. Cascade's GSOC makes these decisions. In recent years, GSOC has adjusted the percentage of the portfolio hedged based on volatility of the market. For example, in the early 2000s, the Company hedged up to 90% of the base gas supply portfolio. When MDU Resources acquired Cascade in 2007, this threshold was reduced to 75% to align with MDU Resources' Corporate Derivatives Policy. As the market began to fall dramatically in the 2008-2010 period, the Company continued to lower the

percentage to approximately 30%. Current MDU Resources' corporate policy encourages Cascade to keep the hedging percentage at approximately 50%. For the 2020 procurement design, GSOC felt that it prudent for Cascade to enter into its first financial derivative during the 2019-2020 period, which the Company successfully executed.

The Company entered into fixed price physical transactions and one financial swap for the current programmed buying period. The Company entered into fixed price physical transactions rather than executing financial swaps for the current programmatic buying period. Fixed prices consist of locked-in prices for physical supplies. As discussed in Appendix E, the Company utilizes a multi-tiered buying approach for locking in or hedging gas supply prices. The Company monitors market conditions and stands ready to execute financial swaps when market and pricing conditions warrant. At the time the current procurement strategy was made, the forward price spread between the November 2019 through October 2020 period and the November 2022 through October 2023 period was less than 20%, which was deemed a reasonable and manageable spread given market intelligence available. Figure 4-5 provides a graph showing the Company's projected weighted average cost of gas (WACOG), including the base case carbon adder, for the 2020 IRP.

Figure 4-5: Projected Cascade WACOG as of June 2020



With the assistance of Gelber & Associates (G&A or Gelber), an energy consulting firm with 30 years of experience in utility hedging, Cascade has continued to evolve its hedging practices to develop a hedging plan that uses a data-driven approach, and provides the flexibility to manage both upside price risk and downside hedge loss risk.

Gelber has been working in close coordination with Cascade to design and implement processes and analytics to comply with the Washington Utility and Transportation Commission UG-132019 policy statement while simultaneously complying with Oregon Public Utility Commission UM-1286 PGA integrated hedging guidelines.

WUTC's Docket UG-132019 requires that hedging programs steer away from inflexible, programmatic practices employed previously to become more "risk responsive" and "data driven". WUTC requires an annual hedging plan submission that demonstrates risk responsive strategies in addition to retrospective hedge reporting. Gelber believes and Cascade concurs that the use of a diversified portfolio of hedging instruments including swaps, call options, and fixed-price physicals is the appropriate design criteria to satisfy Commission requirements.

An update on Cascade's work with Gelber on an evolving hedge program can be found in the Company's 2020 Annual Hedge Plan in Appendix E.

Portfolio Purchasing Strategy

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

GSOC determines the framework for the portfolio design including the allowable percentage of fixed-priced purchases. The execution of the portfolio and the hedging plan is accomplished primarily by the Supervisor of Gas Supply, under the leadership of the Manager of Gas Control & Supply for the Western Region. Either the Supervisor or Manager can execute purchases under the current plan; additionally, they may designate a backup within Gas Supply with the responsibility to execute trades in the event of their absence. The Manager of Supply Resource Planning functions as compliance manager regarding the WUTC's UG-132019 policy statement. These teams are overseen by the Director, Gas Supply—Utility Group.

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

Once GSOC has approved the portfolio procurement strategy and design, the Company employs a variety of methods for securing the best possible transactions under existing market conditions. The Company employs a variety of methods for securing the best possible deal under existing market conditions. CNGC employs a number of processes when procuring fixed-price physical and indexed-riced spot physical. There is a separate process for financial derivatives as discussed throughout this annual hedge plan.

Physical Supply

CNGC utilizes TruMarx's COMET transaction bulletin board system to assist in communicating, tracking, and awarding most activities involving the Company's physical supply portfolio. In the procurement process for physical natural gas the Company posts an RFP to Cascade's 25+ physical supply parties to solicit offers on needed supply. The Company then collect bids from these parties over a period, 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, CNGC awards the posted packages. Please note that posting on COMET does not obligate CNGC to execute any proposal made by physical suppliers.

Naturally, price is the principal factor; however, CNGC also considers reliability, financial health, past performance, and the party's share of the overall portfolio as to ensure party diversity. It should be noted that there is always the possibility the lowest market price may be during period when the Company is initially gathering the price indicatives; in that situation there is a risk that a sudden price run-up may lead to filling the transaction at the higher end of the bids over time or delay the acquisition to another time. However, the reverse is also true—the initial price indicatives may start high and drop over time, allowing CNGC to capture the transaction on the downward swing. In the end, timing is always a factor as the market cannot be perfectly predicted.

Occasionally, an operational situation may occur where time is of essence, such as a need to acquire spot gas to meet sudden swings in load demand or in response to an upstream pipeline operational event. In such situations, CNGC may make a short procurement purchase within a narrow time window to procure and schedule the supply. The Company contacts one to three reliable physical parties to meet these

short-term supply needs. Again, price is the principle but not the only driver for the awarding of these supply needs. Also, please note the Company always encourages physical suppliers to propose other transactions or packages that they feel may be of interest in helping CNGC secure cost effective and operationally flexible transactions to meet CNGC's needs. In addition to analysis using Excel, CNGC also uses the SENDOUT® resource optimization model, which is a useful tool for examining logical, operationally and financially feasible physical packages that best utilizes CNGC's various transportation, storage and operational capabilities.

Financial Derivatives

For financial derivatives, CNGC contacts Company-approved financial counterparties ("counterparties") to request bids consistent with the GSOC approved hedge execution plan (HEP). Naturally, this process requires additional analysis regarding financial reasonableness, timing, hedging strategy, and volumes. The Monthly Guidance and CNG Book Model are the primary tools used to identify and analyze potential financial derivatives possibilities. Price comparisons may also become more complicated since pricing could be tiered; part of a structure deal may be tied to an index or contain floors, caps, etc. Bids are received from the counterparties and, similar to the physical portfolio, the Company then collect bids from these parties over a period, depending on the number or time requirements of the packages sought, comparing the indicative pricing to each party as well as applying the information from market intelligence available at the time. Furthermore, G&A uses MarketView and CNGC has limited access to ICE. Both deliver real-time market pricing information for hedging transactions. Ideally, after monitoring these indicatives and the market, CNGC will award the specific packages to individual parties. Again, please note that CNGC is not obligated to execute any offer received. Further information regarding Cascade's evolving hedge program can be found in the Company's 2020 Annual Hedge Plan in Appendix E.

Conclusion

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

Chapter 5

Avoided Costs

Overview

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

This chapter presents Cascade's avoided cost forecast and explains how it was derived. While the IRP planning horizon is twenty years, avoided costs are forecasted for 45 years to account for the full measure life of some energy efficiency measures, such as insulation, which has a 30-year life. The avoided cost forecast is based on the performance of Cascade's resource portfolio under expected conditions.

Key Points

- Avoided cost forecasting serves as a primary input for determining energy efficiency targets.
- Cascade's avoided costs include fixed transportation costs, variable transportation costs, commodity costs, carbon compliance costs, distribution system costs, a risk premium, and a 10% adder.
- As per WUTC guidelines, Cascade is using the Social Cost of Carbon with a 2.5% discount rate as its base carbon compliance costs
- The total avoided cost ranges between $0.79 and $1.09/therm over the 20-year planning horizon.

Costs Incorporated

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

$$AC_{nominal} = TC_f + TC_v + SC + \left((CC + C_{Comp}) * E_{adder}\right) + DSC + RP$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year. To put this into real dollars apply the following: Avoided Cost/ (1+inflation rate)^Years from the reference year.
- TC_f = Incremental Fixed Transportation Costs
- TC_v = Variable Transportation Costs
- SC = Storage Costs
- CC = Commodity Costs
- C_{Comp} = Carbon Compliance Costs
- E_{adder} = Environmental Adder, as recommended by the Northwest Power and Conservation Council
- DSC = Distribution System Costs

- RP = Risk Premium

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

- The most recent load forecast (6/10/2020);
- The inflation rate used to scale the Social Cost of Carbon (SCC) from Real $2007 to Real $2020 uses the chain type price index for the Gross Domestic Product from the Bureau of Economic Analysis (BEA)[1]
- The discount rate of 3.40% (30-year fixed mortgage rate as of 6/26/2020).

Understanding Each Component

- **Incremental Fixed Transportation Costs**

  In the 2020 IRP, Cascade has not included any additional upstream capacity in its preferred portfolio for the 20-year planning horizon. If such a need were to be identified, fixed transportation costs would represent the average reservation rate of all incremental contracts that would be used to solve shortfalls. Importantly, in some cases, these costs are an estimate based on information from the pipeline companies, and furthermore, are treated as confidential as any incremental fixed transportation costs could ultimately be a negotiated rate.

- **Variable Transportation Costs**

  Variable transportation costs are the cost per therm that Cascade pays only if the Company moves gas along a pipeline. This rate is set by the various pipeline companies and can be changed if one of the pipeline companies files a rate case. The final rates filed at the conclusion of a rate case (whether reached through a settlement or a hearing) must be approved by the Federal Energy Regulatory Commission (FERC) for U.S. pipelines and the Canadian Energy Regulator (CER) for Canadian pipelines. To model rate changes in its forecast, Cascade multiplies its transportation costs by the CPI escalator every four years. Four years is a proxy, since rate cases may not be filed each year.

- **Storage Costs**

  Storage costs are the cost per therm that Cascade would pay for a storage contract that solved some or all of Cascade's peak day shortfalls. This

[1] *See* https://officeofbudget.od.nih.gov/gbiPriceIndexes.html

would include an on-system storage facility, or a satellite LNG facility connected to Cascade's distribution system.

- **Commodity Costs**

  Commodity costs are the costs of acquiring one therm of gas. Cascade first uses SENDOUT® to calculate the monthly percentage of gas that the optimizer would purchase from each of the three basins to serve that climate zone. These weights are then used to derive a single price for the acquisition of that therm. The source for the price that is used for each month's calculation is the monthly price from each year of Cascade's 20-year price forecast.

- **Carbon Compliance Costs**

  Once the Company has calculated its average cost of gas, a price for expected carbon compliance costs must be added. Cascade converts the cost of carbon in dollars per metric ton to dollars per dekatherm, accounting for the upstream natural gas value chain emissions in this calculation. Further information about this calculation can be found in Chapter 6, Environmental Policy. Accurate modeling of these costs has been challenging in years past due to uncertainty surrounding how these costs will ultimately be quantified. For this IRP, Cascade will follow the guidance outlined in Docket U-190730 by using the SCC with a 2.5% discount rate as its base case carbon compliance cost. Cascade will also follow the WUTC guidance for adjusting the values of the SCC from Real $2007 to Real $2020 by using GDP data published by the BEA.

  Cascade calculates the inflation adjusted SCC to start at $78.13/Metric Ton CO_2e in 2021, rising to $104.18/Metric Ton CO_2e in 2040. In Cascade's initial avoided cost calculation, these values were equivalent to $4.02/dth in 2021, rising to $5.36/dth in 2040. After valuable conversations with stakeholders, the Company enhanced its methodology with regards to the accounting of upstream emissions, leading to an adjustment of 2.51%-2.76% per year to the total avoided cost. The results of this adjustment can be seen in Appendix H, Avoided Cost. Overall, carbon compliance costs related to the SCC are a significant factor in Cascade's avoided cost calculation, accounting for a range of 49.64% to 54.69% of the total system avoided cost.

- **Environmental Adder**

  Cascade includes a 10% adder for non-quantifiable environmental benefits as recommended by the Northwest Power and Conservation Council. The 10% adder is added after the cost of gas and taxes are applied.

- **Distribution System Costs**

  Distribution system costs capture the costs of sending gas from the citygate to Cascade's customers. For this IRP cycle, Cascade calculates distribution system costs as its system weighted average of its authorized margins, as posted in the Company's tariffs. Distribution system projects that are not related to growth are then backed out of the weighted margin figure to capture only the costs that can be deemed avoidable. Cascade calculates distribution system costs for both peak day and peak hour, as distribution system analysis is most concerned about system capabilities during a peak hour scenario.

- **Risk Premium**

  Cascade views a risk premium as a cost associated with uncertainty around the other avoided cost factors, versus relative certainty of the costs around energy efficiency programs. For the 2020 IRP, the Company worked closely with its stakeholders to create a methodology to quantify this premium. Cascade requested a hypothetical 20-year fixed price quote from its Asset Management Agreement (AMA) partner, Tenaska Marketing Ventures. The Company then compared the prices offered at each of its basins to its 20-year price forecast. Interestingly, the 20-year fixed prices offered by Tenaska were lower than projected floating market prices, which would lead to a negative risk premium. Thus, Cascade is following regional best practice and recording a value of zero for risk premium instead of the negative values that were calculated.

Application

The 2020 IRP makes several enhancements in calculating and applying the avoided costs, specifically related to its quantification of upstream emissions, accuracy around carbon compliance costs, and enhancements to the distribution system cost calculation methodology. This cost figure becomes the foundation for prudency determinations regarding energy efficiency, both operationally and from a resource planning perspective. It may be helpful to think of the final avoided cost figure as something of a cutoff point. Any action that would save a therm of gas could be evaluated based on the cost per therm saved of that measure. If that number is lower

than the avoided cost, it may make sense to implement that measure. If not, such a measure may not be optimal to engage in.

Cascade locked in the avoided cost on June 24, 2020 as it is a key input to Demand Side Management. The initial avoided cost, which was used for the IRP draft filing, did not include upstream emissions. An upstream emissions workshop was conducted after the fifth TAG meeting and a new avoided cost was locked in after that workshop, on October 15, 2020. As previously mentioned, the final IRP includes upstream emissions in the avoided cost calculation.

Results

Figure 5-1 displays a comparison of the average nominal avoided cost over the 20-year horizon for the current and past IRPs. Figure 5-2 displays the total avoided cost by each conservation zone over the 20-year IRP horizon, while Figure 5-3 provides the net present value of avoided costs over the planning period. Conservation Zone 1 covers the west side of Cascade's service territory, with load centers such as Bellingham, Stanwood, and the Sedro/Wooley area. Conservation Zone 2 refers to the central Washington service area, with load centers such as Bremerton, Longview, and Castle Rock. Conservation Zone 3 covers the eastern Washington service area, including Yakima, Walla Walla, and the Tri Cities. Finally, Zone 4 refers to Oregon citygates. A map of the Conservation Zones can be found in Figure 13-14 in Chapter 13, Glossary and Maps. For the 2020 IRP, nominal system avoided costs range between $0.79/therm and $1.09/therm.

As mentioned earlier, the avoided cost is based on the performance of the portfolio under expected conditions for the entire 20-year planning horizon. Overall, avoided costs for the 2020 IRP are higher than in the 2018 IRP. The main driver of this is higher carbon compliance costs, specifically the change from using an SCC with a 3% discount rate to an SCC with a 2.5% discount rate, as well as the adjustment from real $2007 to real $2020. The 45-year avoided costs and other detailed tables of avoided costs, including various carbon scenarios, are found in the Excel version of Appendix H.

Figure 5-1: Avoided Cost Comparison to Previous IRPs

	2010 IRP	2012 IRP	2014 IRP	2016 IRP	2018 IRP	2020 IRP
Nominal $/Therm	$ 0.810	$ 0.528	$ 0.610	$ 0.571	$ 0.673	$ 0.936

Figure 5-2: Nominal Avoided Costs by Zone (Cost per Therm)

Nominal Avoided Cost including upstream emissions (By Zone) - $/Therm							
	Zone 1	Zone 2	Zone 3	Zone 4	Oregon	Washington	System
2021	$ 0.885	$ 0.876	$ 0.878	$ 0.839	$ 0.839	$ 0.884	$ 0.849
2022	$ 0.842	$ 0.837	$ 0.838	$ 0.809	$ 0.809	$ 0.841	$ 0.816
2023	$ 0.814	$ 0.812	$ 0.812	$ 0.791	$ 0.791	$ 0.814	$ 0.795
2024	$ 0.838	$ 0.835	$ 0.836	$ 0.813	$ 0.813	$ 0.838	$ 0.817
2025	$ 0.882	$ 0.876	$ 0.877	$ 0.852	$ 0.852	$ 0.881	$ 0.858
2026	$ 0.903	$ 0.898	$ 0.899	$ 0.873	$ 0.873	$ 0.903	$ 0.879
2027	$ 0.916	$ 0.911	$ 0.912	$ 0.887	$ 0.887	$ 0.916	$ 0.893
2028	$ 0.919	$ 0.915	$ 0.916	$ 0.889	$ 0.889	$ 0.919	$ 0.894
2029	$ 0.935	$ 0.931	$ 0.931	$ 0.903	$ 0.903	$ 0.934	$ 0.909
2030	$ 0.951	$ 0.947	$ 0.948	$ 0.920	$ 0.920	$ 0.951	$ 0.925
2031	$ 0.958	$ 0.954	$ 0.954	$ 0.927	$ 0.927	$ 0.957	$ 0.932
2032	$ 0.977	$ 0.973	$ 0.974	$ 0.946	$ 0.946	$ 0.977	$ 0.952
2033	$ 0.995	$ 0.991	$ 0.992	$ 0.964	$ 0.964	$ 0.995	$ 0.969
2034	$ 1.002	$ 0.999	$ 0.999	$ 0.971	$ 0.971	$ 1.002	$ 0.977
2035	$ 1.020	$ 1.017	$ 1.017	$ 0.988	$ 0.988	$ 1.019	$ 0.993
2036	$ 1.033	$ 1.031	$ 1.031	$ 1.002	$ 1.002	$ 1.033	$ 1.007
2037	$ 1.057	$ 1.053	$ 1.054	$ 1.025	$ 1.025	$ 1.057	$ 1.031
2038	$ 1.079	$ 1.075	$ 1.076	$ 1.047	$ 1.047	$ 1.079	$ 1.053
2039	$ 1.103	$ 1.098	$ 1.099	$ 1.070	$ 1.070	$ 1.102	$ 1.076
2040	$ 1.117	$ 1.113	$ 1.114	$ 1.085	$ 1.085	$ 1.117	$ 1.091

Figure 5-3: Real $2020 Avoided Costs by Zone (Cost per Therm)

Real 2020$ Avoided Cost including upstream emissions (By Zone) - $/Therm							
	Zone 1	Zone 2	Zone 3	Zone 4	Oregon	Washington	System
2021	$ 0.885	$ 0.876	$ 0.878	$ 0.839	$ 0.839	$ 0.884	$ 0.849
2022	$ 0.814	$ 0.810	$ 0.810	$ 0.783	$ 0.783	$ 0.814	$ 0.789
2023	$ 0.761	$ 0.759	$ 0.760	$ 0.740	$ 0.740	$ 0.761	$ 0.744
2024	$ 0.758	$ 0.755	$ 0.756	$ 0.735	$ 0.735	$ 0.758	$ 0.739
2025	$ 0.771	$ 0.767	$ 0.768	$ 0.746	$ 0.746	$ 0.771	$ 0.751
2026	$ 0.764	$ 0.760	$ 0.760	$ 0.739	$ 0.739	$ 0.764	$ 0.744
2027	$ 0.750	$ 0.746	$ 0.746	$ 0.726	$ 0.726	$ 0.749	$ 0.731
2028	$ 0.727	$ 0.724	$ 0.725	$ 0.703	$ 0.703	$ 0.727	$ 0.708
2029	$ 0.715	$ 0.712	$ 0.713	$ 0.691	$ 0.691	$ 0.715	$ 0.696
2030	$ 0.704	$ 0.701	$ 0.702	$ 0.681	$ 0.681	$ 0.704	$ 0.685
2031	$ 0.685	$ 0.683	$ 0.683	$ 0.663	$ 0.663	$ 0.685	$ 0.667
2032	$ 0.677	$ 0.674	$ 0.674	$ 0.655	$ 0.655	$ 0.676	$ 0.659
2033	$ 0.666	$ 0.663	$ 0.664	$ 0.645	$ 0.645	$ 0.666	$ 0.649
2034	$ 0.649	$ 0.647	$ 0.647	$ 0.629	$ 0.629	$ 0.649	$ 0.633
2035	$ 0.639	$ 0.637	$ 0.637	$ 0.619	$ 0.619	$ 0.638	$ 0.622
2036	$ 0.626	$ 0.624	$ 0.624	$ 0.607	$ 0.607	$ 0.626	$ 0.610
2037	$ 0.619	$ 0.617	$ 0.617	$ 0.600	$ 0.600	$ 0.619	$ 0.604
2038	$ 0.611	$ 0.609	$ 0.609	$ 0.593	$ 0.593	$ 0.611	$ 0.596
2039	$ 0.604	$ 0.602	$ 0.602	$ 0.586	$ 0.586	$ 0.604	$ 0.589
2040	$ 0.592	$ 0.590	$ 0.590	$ 0.575	$ 0.575	$ 0.592	$ 0.578

Chapter 6

Environmental Policy

Purpose

This chapter considers Greenhouse Gas (GHG) emission reduction policies and regulations that have the potential to impact natural gas distribution companies. In addition, this chapter examines methodologies for applying a cost of carbon to natural gas distribution companies and identifies the assumptions made in determining a 45-year avoided cost of natural gas and pairs these costs with associated two-year action items.

Since the last IRP, policymakers in Washington and Oregon continue to actively pursue GHG emission reductions while the Federal Government has lessened its focus on the pursuit of reductions.

Key Points

- State and federal agencies continue proposing GHG emission reduction regulations and are considered in the 2020 IRP.
- Cascade models SCC at 2.5% discount rate as its main carbon forecast, including sensitivities of a Cap and Trade pricing forecast and two Congressional Proposals: House of Representatives Raise Wages, Cut Carbon Act and the Market Choice Act.
- On Jan. 16, 2020 WA Supreme Court invalidated CAR WAC-173-442 for non-emitters.
- Cascade continues to monitor federal and state regulation and congressional and state legislative actions.
- On March 20, 2020 Oregon Governor Brown issues EO 20-04 directing state agencies to reduce GHG emission under their existing authority with DEQ to commence cap and reduce requirements by Jan. 1, 2022.

Company Environmental Policy

Cascade's policy states:

"The Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. The environmental goals are:

> *To minimize waste and maximize resources;*
>
> *To be a good steward of the environment while providing high quality and reasonably priced products and services; and*
>
> *To comply with or surpass all applicable environmental laws, regulations and permit requirements."*

Cascade is committed to maintaining compliance with all laws and regulations and strives to operate in a sustainable manner, while taking into consideration the cost to customers. Cascade actively engages in public proceedings related to federal and state legislative and regulatory activities. This includes offering comments on environmental policy, including air emissions and other environmental requirements. The Company has also established memberships in relevant trade organizations to assist in monitoring the potential impact of proposed legislation

and regulation to the Company's operations. Cascade's goal is to ensure safe, affordable, reliable energy for our customers while serving as stewards of our natural resources.

Overview

Cascade monitors environmental regulatory requirements in progress nationally, regionally, and locally that have the impacts to local distribution companies (LDCs). As of November 17, 2020, there are no regulations at the federal level that would require the Company to reduce GHG emissions. Also, there are currently no direct regulations or laws applying a carbon price to Cascade operational GHG emissions or GHG emissions resulting from customer use of natural gas which Cascade sells to customers. However, there are several policies with emergent implications for carbon emission pricing and reductions in both Washington State and Oregon. These include the WA Greenhouse Gas Assessment for Projects (GAP) rulemaking led by the Department of Ecology, and Governor Kate Brown's Executive Order 20-04 Directing State Agencies to Take Actions to Reduce and Regulate Greenhouse Gas Emissions.

The requirements discussed in this section are projected to be the most informative for the Company to determine how to model potential impacts of carbon pricing in the IRP. With discussion in both states served by Cascade centering on the valuation and quantification of carbon and other GHG emissions there is a high potential for a cost of carbon to impact Cascade in the future.

Only a limited number of congressional bills proposing GHG reductions have been drafted during former President Trump's administration and those bills focused mainly on the electric industry and none passed into law. President Biden announced his "Build Back Better" plan for reducing GHG emissions during his campaign for president. Cascade will continue to monitor how this plan is introduced in legislation and review requirements that would apply to natural gas utilities.

Further, on a federal level, there have been programs established to provide platforms to encourage LDCs to make voluntary commitments in reducing GHG emissions. One of the voluntary platforms is EPA's Natural Gas Star Methane Challenge Program. The Methane Challenge Program was established by EPA in collaboration with oil and natural gas companies with Cascade participating as a founding partner of the program in March 2016 along with about 50 other companies. Partners in the program demonstrate their commitment and concern for the environment through voluntary methane emissions reductions.

In the previous IRP, Cascade used the Social Cost of Carbon (SCC) with a three percent discount rate that was established by the Interagency Working Group (IWG) on Social Cost of Greenhouse Gases to model societal costs of GHG emissions resulting from customers' combustion of natural gas. The SCC is estimated using different discount rates to develop a range of costs in dollars per ton of CO_2 that would represent the avoided cost of long-term damage from climate change caused by a ton of CO_2 emitted in a given year. Agencies, such as the EPA, have used the SCC in determining the cost of climate impacts from rulemakings. For this IRP, as suggested by WUTC and outlined in Docket U-190730, Cascade is applying the SCC with a two and one-half percent discount rate as the main CO_2 adder in modeling.

From the state perspective, Washington and Oregon have adopted regulations and legislation limiting GHG emissions predominantly from electric utility fossil-fired electric generation resources and continue to explore expansion of GHG regulation to other sectors.

The Company has been involved in state-focused evaluation of renewable natural gas (RNG) opportunities in Washington and Oregon, and also monitors federal efforts on development of RNG policy through the Company's membership in trade organizations. Cascade has included a preliminary analysis of renewable natural gas projects in the Company's service area in Appendix J. Additionally, the Company is currently in the process of soliciting a third-party consultant to support an assessment of the total RNG potential available to Cascade as it seeks to ramp-up renewable efforts.

From a regional perspective, Cascade reviews energy and GHG emissions analyses published by the Northwest Power and Conservation Council (NWPCC or Council) to inform on cost impact and potential future regional policy development. Cascade reviewed the NWPPC Seventh Plan for the Company's IRP. The NWPCC is scheduled to release a new Plan in 2021.

There continues to be community-driven efforts in adopting GHG emission reduction targets within, and adjacent to, Cascade's service areas. Communities such as the city of Bellingham and Whatcom County, Washington, have adopted a decarbonization strategy which includes more challenging and aspirational GHG emission reduction measures. At the time this chapter was drafted, Bellingham City Council was currently working with City staff to assess a series of Climate Action Task Force (CATF) recommendations for potential integration into the City's Climate Action Plan. Such measures include exploring the electrification of new homes and buildings within Bellingham. The City of Bend, Oregon has also adopted GHG reduction measures. Their approved plan has expanded Cascade's discussions with the City regarding potential future partnership on RNG development and community-wide carbon offset programs. Cascade has engaged

with these communities and is working with them to support GHG emission reduction targets and goals as appropriate while supporting the triple bottom line of economics, equity, and sustainability.

Cascade examines the policies and regulatory activities mentioned above in determining the GHG emission or carbon costs to model in IRP analyses. The Company considers both proposed and final regulations and legislation in this process. The following subsections provide more explanation of the policy and regulatory development that would be most informative in determining how to best model potential carbon impacts on Cascade's operations and customers. Cascade explains its approach and support for carbon cost modeling for this IRP. Cascade also includes further discussion on GHG emissions in general, as well as actions and commitments the Company has taken to reduce GHG emissions.

Federal Regulation and Policy

1. Congressional Actions

Cascade monitors congressional actions on reducing GHG emissions and a few recent examples, as well as President Biden's proposed plan for reducing GHG emissions, are provided below.

a. U.S. House of Representatives Market Choice Act (HR 6463)

The Market Choice Act was introduced in the U.S. House of Representatives on July 23, 2018. This bill includes provisions for addressing GHGs, including a carbon tax for combustion of fossil fuels. The bill proposes to apply an initial tax of $24/ton of CO_2 equivalent emitted from fossil fuel combustion starting in 2020 which would escalate annually by 2% plus an inflationary adjustment. Affected emissions would be quantified annually to determine if annual caps identified in the bill are met. If GHG emissions caps are not met, the tax would increase an additional $2/year. Although this bill did not pass, it provides an example of a cost of carbon resulting from congressional action. The Company is using the Market Choice bill as a CO_2 adder sensitivity as it represents a recent congressional outlook of potential carbon pricing for fossil fuels.

b. U.S. House of Representatives Raise Wages, Cut Carbon Act (HR 3966)

In 2019, the Raise Wages, Cut Carbon Act (HR 3966) was introduced in the U.S. House of Representatives. This bill would apply a tax to importers of fossil fuels and fluorinated greenhouse gases and use tax revenues to

reduce social security taxes, as well as increase funding for the low-income home energy assistance program and the weatherization assistance program for low-income persons. The tax would apply to (1) the manufacturer, producer, or importer of coal (including lignite and peat), petroleum and petroleum products, and natural gas; (2) any imported taxable product sold or used by its importer; and (3) fluorinated greenhouse gases. Generally, the tax would start at $40/metric ton of CO_2 equivalent emitted and increase 2.5%/year plus inflation but may also depend on other factors. This rate could be increased if emission reduction targets are not met. The Company is using the Raise Wages, Cut Carbon Act as a CO_2 adder sensitivity as it also represents a recent congressional outlook of potential carbon pricing for fossil fuels.

c. Other Congressional Activities

Other federal legislative activities Cascade has monitored include the Climate Leadership and Environmental Action for the Nation's (CLEAN) Future Act discussion draft developed in the U.S. House of Representatives Energy and Commerce Committee, American Energy Innovation Act (AEIA) S.2657 developed in the U.S. Senate Energy and Natural Resources Committee, U.S. Senate Clean Energy Innovation and Deployment Act (CEIDA) and President Biden's climate action GHG emissions reductions proposed in his "Build Back Better" plan. Each have national GHG emission reduction achievement targets or plans varying in application to certain sectors or economy-wide. Cascade is monitoring these ongoing congressional activities, but not including these proposals in modeling.

2. Social Cost of Carbon (SCC)

The SCC is estimated using different discount rates to develop a range of costs in dollars per ton of CO_2 that would represent the avoided cost of long-term damage from climate change caused by a ton of CO_2 emitted in a given year. Agencies, such as the EPA, have used the SCC in determining the cost of climate impacts from rulemakings. Other agencies, such as FERC, continue to consider whether and/or how to incorporate the SCC into their permitting and rulemaking processes.

Cascade modeled societal costs of CO_2 emissions resulting from customers' combustion of natural gas in the previous IRP using the SCC with a three percent discount rate that was established by the U.S. Governmental Interagency Working Group (IWG) on Social Cost of Greenhouse Gases. In this IRP and in consideration of HB 1257 adding further instruction in RCW 80.28 on conducting avoided cost calculations, Cascade is applying the SCC with a two and one-half percent discount rate

from the IWG's August 2016 SCC report as the main CO_2 adder in modeling impacts of a potential price that could be placed on CO_2 emissions from customers' usage of natural gas.

State Regulation and Policy

New environmental regulations and policies continue to be proposed in Washington and Oregon. The purpose of these proposals is to address GHG emissions resulting from the use of fossil fuels. Some of these regulations could have the potential to increase Cascade operating costs and/or reduce sale of natural gas.

1. Washington

Since the previous IRP, the Washington State Supreme Court invalidated the Clean Air Rule (CAR) for non-emitters (natural gas distribution companies) and remanded the case to Thurston County Superior Court for further proceedings. Washington environmental legislative action included carbon tax and cap and trade proposals that did not pass. The Clean Buildings Act passed which provides new targets for energy efficiency and allows utilities rate recovery on certain renewable natural gas investments. The state also continued to pursue energy and building code revisions.

a. Washington Department of Ecology (Ecology) Clean Air Rule (CAR)

On September 15, 2016, the Washington Department of Ecology (Ecology) issued the final Washington CAA CAR WAC-173-442 requiring greenhouse gas emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. On the same date, Ecology finalized requirements for reporting GHG emissions from natural gas distributors under WAC 173-441.

On September 27, 2016 and September 30, 2016, Cascade and three other natural gas distribution utilities jointly filed complaints in the United States District Court for the Eastern District of Washington and the State of Washington Thurston County Superior Court, respectively, challenging the legal underpinnings of CAR. On December 15, 2017, Thurston County Superior Court Judge James Dixon ruled that Ecology can limit GHG emission from direct emitters, but LDC and petroleum producers are not direct emitters, and

invalidated CAR based on that argument. Later that December, Ecology suspended all rule requirements.

On May 16, 2018, Ecology filed an appeal with the Supreme Court of Washington and the court issued a 5-4 decision on January 16, 2020 vacating in-part and upholding in-part the lower court's decision to vacate CAR. The Court conclusively determined that the Clean Air Act's purpose section does not authorize Ecology to set emission standards for "indirect emitters" (such as natural gas utilities). The court went on to sever the portions of the rule as they applied to actual emitters (the direct emitter sources) and remanded to the Superior Court for further proceedings. HB 2957 was introduced to amend existing law to allow CAR to regulate "indirect emitters". A compromise between parties on certain issues in the bill was successful and the bill died when the legislature adjourned.

At this time, parties have filed status reports with the court agreeing to delay proceedings in Superior Court. Ecology has expressed the desire to evaluate its position on whether additional regulatory changes may be needed and requested additional time due to delays caused by COVID-19 and mandatory furloughs.

b. Washington Department of Ecology (Ecology) - GHG Assessment for Projects (GAP)

At the end of 2019, Governor Inslee directed Ecology to adopt a rule by Sept 1, 2021 to consider GHG emissions in environmental assessments for major industrial projects and major fossil fuel projects with significant environmental impacts. Ecology announced rulemaking commencement on April 30, 2020 and is currently engaging stakeholders to obtain input for drafting a proposed rule in late 2020. Ecology has requested input on whether and how the agency should incorporate mitigation of GHG emissions from projects that would require review. If mitigation of emission would be required, Cascade anticipate the cost to utilize natural gas for these types of projects would increase. This regulatory action does not have an impact on this IRP but may impact future IRPs.

c. 2019 Clean Buildings Act - HB 1257

On July 28, 2019 HB 1257, the Washington bill concerning energy efficiency improvements, went into effect. The law set new requirements for conservation planning, and energy efficiency target setting, as well as new rules governing the development of

conservation potential assessments. It also added language to RCW 80.28 to allow for the recovery of certain renewable natural gas investments under the guidance of the WUTC. Cascade is currently engaged in workshops and other regulatory discussions to fully understand the changes that will need to be made to energy efficiency programs, and what opportunities may arise concerning renewable natural gas. Further details on energy efficiency and renewable natural gas plans can be found in Chapter 12, Two-Year Action Plan.

HB 1257 also added language to RCW 80.28 instructing utilities to utilize the two and one-half percent discount rate in Table 2 of the IWG August 2016 update to the Social Cost of Carbon, and adjust costs for inflation, in applying a cost of carbon in avoided cost calculations. Cascade has applied this methodology to avoided costs presented in this IRP.

d. Building Code Changes

On November 8, 2019, the Washington State Building Code Council ("SBCC") voted to approve the Fuel Normalization and Additional Credits tables in Section R406.2 with an electric emissions factor of 0.7 lbs/kwh instead of the previously approved carbon emissions factor of 0.8 lbs/kwh for electricity. Under this new language, an electric heat pump receives one credit assigned when the 0.7 lbs/kwh carbon emissions factor is used. This results in a full credit going to homes using a minimum code electric heat pump and has tilted the selection of heating systems in that direction and away from efficient gas furnaces (which do not receive similar treatment under the code). Cascade continues to evaluate the impact of the code change and address this in the Company's 2021 Conservation Plan.

e. Washington Department of Commerce (Commerce) State Energy Strategy

The Department of Commerce has released the first draft of its 2021 State Energy Strategy. As part of its planning efforts, Commerce commissioned a study with Evolved Energy Research to identify cost-effective pathways to decarbonization. The draft Energy Strategy concludes that full electrification is the best-cost pathway for decarbonization. The draft also includes several recommendations that would impact all facets of energy policy— such as integrated resources planning— and would have significant impacts on both energy costs and grid reliability. Cascade believes

it will be essential for the Commerce report to be compared against a review of other decarbonization and economic studies before a final draft of policy recommendations is released. In the meantime, Cascade will continue to monitor Commerce's development of the State Energy Strategy and provide ongoing feedback as appropriate. This does not impact this IRP but may impact future IRPs.

f. Other Washington 2020 Legislative Activity

Cascade is keeping apprised of additional legislation in Washington State with the intent to reduce GHG emissions. No carbon pricing legislative initiatives in Washington passed into law in the last session. A couple bills affecting GHG emissions reductions from this last session that passed are HB 2311 and HB 2518. HB 2311 updated Washington's GHG emissions reduction goals to 45% below 1990 levels by 2035, 75% below 1990 levels by 2040, and 95% below 1990 levels by 2050. HB 2518, the Natural Gas Transmission bill, requires natural gas transmission and distribution companies to expedite mitigation of hazardous leaks, reduce as practicable non-hazardous leaks, and provides utilities rate recovery to mitigate these leaks. Cascade is working with the other distribution companies in Washington state on implementing these actions.

Cascade anticipates some form of carbon emissions reduction or carbon pricing legislation could be introduced in the next legislative session which would have a direct impact on the use and price of natural gas. These legislative activities do not impact this IRP but may impact future IRPs.

g. Preliminary Washington 2021 Legislative Activity

Two decarbonization bills have been introduced in the 2021 Washington legislative session that have significant potential to impact natural gas usage and rates in the State of Washington. These bills are not included in IRP modeling.

House Bill (HB) 1084 is a buildings decarbonization bill aiming to reduce statewide greenhouse gas emissions through electrification of residential and commercial buildings. The bill also promotes reduced energy consumption in buildings and institutes electrification of buildings by eliminating natural gas as a fuel choice for space and water heat. It would also remove a gas utility's obligation to serve. As introduced, the UTC would be required to establish a surcharge to natural gas utilities to switch their natural gas customers to

electricity. The bill would additionally limit expansion of the natural gas distribution system for residential and commercial space and water heating.

As of the time of this filing, Senate Bill (SB) 5126 is a cap and invest program for reducing Washington economy-wide GHG emissions. Allowances, a portion of which would be required to be consigned at auction, would be provided to natural gas utilities at no cost for the benefit of customers, deposited for compliance, or a combination of both. The program would be implemented by the Department of Ecology by January 1, 2023.

Cascade is monitoring and engaging actively on both proposals.

2. Oregon

Since the previous IRP, Oregon environmental legislative action focused on GHG cap and trade programs and RNG development. As no GHG cap and trade program passed, Governor Brown released an Executive Order (EO) for state agencies to implement GHG reductions within their authority. Discussion of this EO is provided below. Discussion on Oregon RNG SB 98 legislation and subsequent PUC rulemaking are provided in Chapter 8, Renewable Natural Gas.

a. Executive Order (EO) No. 20-04

The Oregon State Legislature did not reach consensus on a direction this year regarding cap and invest legislation. As a result, Governor Kate Brown issued Executive Order 20-04, directing state commissions and agencies to facilitate achievement of new GHG emissions goals of at least 45% below 1990 levels by 2035, and at least 80% below 1990 levels by 2050. The order specifically directs the Environmental Quality Council (EQC) and Department of Environmental Quality (DEQ) to take actions necessary to cap and reduce GHG emissions. EO 20-04 is also intended to build on EO 17-20, Accelerating Efficiency in Oregon's Built Environment to Reduce Greenhouse Gas Emissions and Address Climate Change.

EO-20-04 includes 13 directives to multiple state agencies establishing reporting requirements and deadlines for implementing GHG reductions. Specifically, the EO directs the EQC and DEQ to take actions necessary to cap and reduce GHG emissions, consistent with the new GHG emissions goals from large stationary

sources, transportation fuels, and other liquid and gaseous fuels, including natural gas. As the EQC and DEQ do not appear to have the authority to implement a market-based cap and trade type system, it is anticipated that emissions would be capped at a baseline emissions value with a limited number of allowances distributed to regulated entities and these allowances would decline over time. The EO directs DEQ to commence cap and reduce program options no later than January 1, 2022.

The first reporting deadline associated with EO 20-04 was on May 15, 2020. The Governor designated state agencies to report on proposed actions within their statutory authority to reduce GHGs and mitigate climate change impacts. DEQ published a report describing the EQC's legal authority to cap and reduce GHG emissions and proposed a process for rulemaking. DEQ has sought input from the public over the past months to inform the agency's rulemaking approach and design. Cascade has engaged in the public meetings and provided input to DEQ.

The GHG reductions for natural gas suppliers are likely to have substantive impacts to Cascade's customers. However, the rule has not yet been drafted and the cost impacts are currently unknown. If the same reduction goals are applied to natural gas distribution utilities as in past Oregon legislative actions, Cascade's residential and commercial customers may see rate increases in their bills starting in the first year the reductions are to be implemented and increase over time as compliance requirements would increase.

DEQ plans to commence formal rulemaking work with the appointment of a rules advisory committee (RAC) by the end of November 2020. To help inform the rulemaking design and considerations for natural gas suppliers, Cascade has nominated Alyn Spector from Cascade for the RAC. DEQ plans to host RAC meetings and any additional public or invited stakeholder meetings in early 2021 and to release a notice of rulemaking packet for public comment in Summer/Fall 2021. The rulemaking packet is expected to be provided to the EQC in Fall 2021. DEQ has not determined a final cap and reduce timeline/trajectory or compliance obligation for regulated entities. Cascade will continue to monitor these potential impacts as part of its resource planning. This rulemaking does not have an impact on this IRP but is provided for general understanding of regulatory activities occurring in Cascade service areas in the neighboring state of Oregon.

Regional Policy

The NWPCC examines CO_2 costs in its periodically published Power Plans. The NWPCC's Seventh Power Plan, released in May 2016 is considered a recognized standard for carbon analysis in the Pacific Northwest and Cascade utilized the Seventh Plan's projected CO_2 costs to model cost impacts to natural gas distribution utilities in the 2016 IRP. The next Power Plan is expected to be published in 2021. The Company will continue to review and consider NWPCC's updated reports for modeling costs in future IRPs.

Local Policy

In the past few years, Cascade has observed a heightened interest by local jurisdictions and municipalities in committing to the reduction of GHG emissions within a municipality, as well as some applying commitments community-wide. Those cities or counties establishing commitments are focusing on goals and aspirations in the range of 80% GHG reductions relative to 1990 levels by 2050, which is consistent with the Paris Climate Agreement.

For background, the Paris Climate Agreement was a pact made by many countries across the globe, responding to concerns regarding climate change. In the pact, countries committed to GHG reductions to limit increasing global temperatures and fund response to impacts of climate change. The U.S. had been a party to the pact in 2015 and in 2017, former President Trump withdrew the U.S. from the Paris Climate Agreement. President Biden re-entered the U.S. into the Paris Climate Agreement on February 21, 2021. Cascade will monitor this for any impacts it may have on future IRP cycles.

Within Cascade's service areas, the City of Bellingham and Whatcom County in Washington, and the City of Bend, Oregon have developed GHG reduction goals. A summary of those commitments is provided below. Also, Snohomish County, which overlaps Cascade's service area, created an ad hoc Climate Advisory Committee in 2019 to provide recommendations in the next few years that encourage adoption of policies, programs, and practices in order to reduce GHGs, address climate change, protect public health, and preserve the natural environment within the county. The Company is considering how it should utilize local policies as these goals are stated as aspirational and goals continue to be evaluated by these local entities.

There are other areas adjacent to Cascade's service areas adopting similar commitments, such as Tacoma, Seattle, and Edmonds, Washington, Multnomah County and Portland, Oregon, and Vancouver, British Columbia. Cascade has also

observed adoption of energy action plans to switch from gas to electric in the Cities of Ashland and Eugene.

1. **City of Bellingham, Washington**

The City of Bellingham passed a GHG Reduction and Renewables Energy Targets resolution in March 2018 updating emission reduction targets for municipal facilities and operations to reduce emissions 85% below 2000 levels by 2030, and 100% below 2000 levels by 2050, making the city facilities and operations carbon-neutral. Bellingham also included in the resolution a target to reduce community-wide emissions 70% below 2000 levels by 2030, and 85% below 2000 levels by 2050. Specifically, the goals are to obtain energy from all renewable resources and remove use of fossil fuels by 2030 and 2035 within the city, including transportation.

The City created the Climate Action Task Force to explore and recommend how the city and community can meet these new targets, taking into account technology, feasibility, possible accelerated targets, funding mechanisms, as well as costs and other impacts. The task force included community members that have experience in renewable energy, energy conservation, land use, energy/resource economics, community engagement, transportation, and finance. Energy utility representation and public transportation representatives were identified. However, the City did not allow more than one utility representative at the table and Puget Sound Energy (PSE) was chosen by the City to represent utilities on the task force. Cascade worked together with PSE to include Cascade's input. Minimal input was accepted from Cascade, and efforts seemed primarily focused on electrification to the exclusion of other decarbonization strategies that utilize offsets and renewable natural gas as pathways to carbon reduction.

The task force first met on September 5, 2018 and continued to meet regularly through late 2019. On December 2, 2019, the task force finalized a report of GHG reduction recommendations. City staff reviewed the Task Force recommendations and narrowed them down to those most likely to be integrated successfully and discussed the results with the City Council. City staff used a tiered ranking system for this evaluation, considering such factors as whether the measure has already been implemented, needed further research and analysis, or tabled for future review. The measures will go through a triple bottom line "plus" assessment before adding to the City's Climate Action Plan (CAP).

In the next 6 months, the City Council will amend the CAP, and City staff will develop a Climate Implementation Plan. The implementation plan will be reviewed ongoing. The City is currently working cross-departmentally to

determine which of the CATF's recommendations should be integrated into Bellingham's Climate Action Plan. Ten recommendations are currently being vetted, including encouraging the State to ban internal combustion engine vehicles, expanding weatherization efforts, and disallowing the use of natural gas in new homes and buildings. At this time, the City Council is seeking additional information before these measures are folded into the CAP. Additional detail can be found on the following City of Bellingham webpage: https://www.cob.org/services/environment/climate/Pages/program.aspx.

2. Whatcom County, Washington

Whatcom County, in which the City of Bellingham is situated, has committed to the "Ready for 100" campaign that the Sierra Club is advocating and has established goals through a county ordinance. The "Ready for 100" campaign website recommends a goal of 100% renewable electricity by 2035 and 100% renewable for all other energy sectors by 2050, but participants can target less stringent goals. Whatcom County has chosen to commit to 100% renewable electricity for county operations by 2035 and plans to also apply the goal for the larger Whatcom County community.

Whatcom County established a Climate Impact Advisory Committee which provides review and recommendations to the Whatcom County Council and Executive on issues related to the preparation and adaptation for, and the prevention and mitigation of, impacts of climate change. The committee has continued to meet on climate and energy policy.

3. City of Bend, Oregon

The City Council of Bend, Oregon passed Resolution 3044 in 2016 establishing voluntary GHG emission reduction goals for City facilities and operations of 40% reduction of 2010 baseline year emissions by 2030 and 70% reduction of 2010 baseline year emissions by 2050. The City Council passed another resolution, Resolution 3099, which created a Climate Action Steering Committee (CASC). The CASC provided recommended actions to the City Council that encourage and incentivize businesses and residents, through voluntary efforts, to reduce GHG emissions and fossil fuel use considering the voluntary goals.

Cascade was appointed to the CASC, and actively engaged in supporting the development of a viable pathway forward that considers the essential balance between the City's economic vitality, reliability of its energy supply, and environmental goals. The CASC authored a plan recommending a set

of strategies to guide both the City and the surrounding community in achieving its goals.

On December 4, 2019, the Bend City Council approved the Climate Action Steering Committee's (CASC) recommendations concerning a pathway to reducing its fossil fuel use by 40% by 2030, and by 70% by 2050. Cascade publicly supported the recommendations presented to the City. Cascade is now engaged with Bend City staff and other members of the community to identify ways to help the City meet its targets. Possible pathways forward include partnerships on the integration of biogas, and possible carbon offset programs.

Natural Gas Industry Emissions

From review of EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2018, in 2018 the oil and gas sector was estimated to emit about 10.7% of the total GHG emissions from all industries, equating to approximately 319 million metric tons of CO_2 equivalent per year. LDC facilities and operations contribute to GHG emissions generally through fugitive methane emissions and leaks from pipeline infrastructure, as well as from combustion of fuel in compressors. EPA's emissions estimates indicate a little over four percent of oil and gas sector emissions are from LDC infrastructure, equating to about 13 million metric tons of CO_2 equivalent per year.

Cascade is required to report annual facility GHG emissions to EPA and the State of Washington. These emissions have generally been in the range of about 24,000 to 27,000 metric tons of CO_2 equivalent per year. Cascade's facility GHG emissions in Oregon are lower and have not been required to be reported to EPA or the State of Oregon in the past. However, the Oregon Department of Environmental Quality finalized a GHG reporting rule earlier in 2020 that requires Cascade to report annual facility GHG emissions to the State of Oregon starting in 2021.

Upstream Natural Gas Value Chain Emissions

GHG emissions in the oil and gas sector include fugitive methane emissions from well/pipeline infrastructure and well completion processes, as well as GHG emissions from natural gas flaring, compressor engines and other combustion equipment. There is continued debate on contribution of these emissions and how to consider emissions in total energy supply chain since emissions studies vary.

Noted in Chapter 3 of the NWPCC's Seventh Power Plan,[1] the uncertainty around how to consider impacts from methane emissions and what assumptions to make about methane impacts from the regions' supply of natural gas and infrastructure:

> *"…there is considerable uncertainty around such issues as whether its impacts compared to carbon dioxide are over or under-stated…and whether accounting for the methane emissions from coal production would also raise that fuel's full life-cycle climate impacts…"*
>
> *"…will likely draw on gas production from new wells which have lower fugitive emissions…"*
>
> *"…unless new pipeline capacity is needed, fugitive emissions from pipeline leaks remain relatively constant…"*

As the NWPCC has prepared for the next Power Plan release, the Council further explored upstream emissions for modeling emissions from fossil-fired electric generating units. The Council created a Natural Gas Advisory Committee (NGAC)[2] in June 2020 which met to evaluate upstream methane emissions studies and to provide input to the Council on upstream methane emissions. Based on this review, the NGAC recommended the Council use an upstream methane release rate of 1.37% for natural gas used in the region. This was derived after reviewing studies and choosing a value that is a weighted mix from an estimate of gas from the British Columbia and U.S. Rockies. Cascade, through membership in the Northwest Gas Association (NWGA), expressed concern in a letter to the Council[3] about the upstream emissions loss rate chosen by the Council for the U.S. Rockies, among other concerns regarding the application of upstream emissions to only certain generation resources. In the letter, NWGA took exception to the application of a 2.47% emission rate for the U.S. Rockies since it is not believed to represent an appropriate regional emission rate, is an older snapshot in time, and was derived from site-based estimates in the Environmental Defense Fund (EDF) study published in Science Direct (Alvarez, 2018)[4] and not the source-based (life-cycle) emissions estimates reviewed in that study which were more closely approximate to the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks.[5]

Per language added to RCW 80.28.395[6] from passage of HB 1257 in 2019, natural gas utilities are to include upstream emissions in the avoided cost calculations in

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[1] NWPCC's Seventh Power Plan.
[2] NWPCC Natural Gas Advisory Committee webpage.
[3] Letter included in the June 17, 2020 Council briefing packet.
[4] Science, 13 Jul 2018, Vol. 361, Issue 6398, pp. 186-188.
[5] EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks website.
[6] RCW 80.28.395.

determining conservation program potential. Cascade reviewed the upstream emissions values from the Council's evaluation of natural gas supplied from Canada and the U.S. Rockies,[7] One Future Coalition[8] reported values, values chosen by other utility companies, and EPA reported GHG data from the oil and gas industry segments in choosing an upstream emissions factor for estimating upstream emissions. For this IRP, Cascade has chosen to use a 0.77% upstream emissions loss rate for natural gas supplied from Canada and a 1.0% upstream emissions loss rate for natural gas supplied from the U.S. Rockies.

For the U.S. Rockies, the 1.0% upstream emissions loss rate chosen is a rate calculated by the American Gas Association (AGA) in a June 2020 Energy Analysis Report[9] which is based on 2018 emissions data compiled by EPA in the agency's most recent Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018.[10] AGA's report explains the calculation of this emissions loss rate the assumptions applied. There are other estimates of upstream emissions reported by various entities and sources. Cascade has chosen to use the 1.0% loss rate AGA calculated for the U.S. Rockies since it is based on the EPA GHG inventory[11] which considers emissions data regularly evaluated and updated, vetted through engagement with industry and technical experts and other public stakeholders. This value is also in the range of other upstream emissions factors noted in recent project literature, as provided in Table B.4 of Appendix LCA-B: Upstream Lifecycle Emissions in Appendix B: PSE Tacoma LNG Project GHG Analysis Final Report of the Final Supplemental Environmental Impact Statement (SEIS) for the Proposed PSE Tacoma LNG Plant[12] and the 3-StudyResults tab of the NWPCC Methane 2021 Power Plan Workbook.[13]

Cascade also notes that the 1.0% loss rate chosen is in the range of, but notably higher than, the emissions intensity reported in One Future Coalition's 2018 Methane Intensities Report.[14] One Future reported an estimated 0.33% methane lost per methane throughput from the natural gas segment considering data compiled and reported through their membership. Some of the members of One Future are within the natural gas supply chain for Cascade and their One Future membership would serve to further support Cascade's use of a loss rate in the range of 1.0%.

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[7] Ibid 6-17.

[8] One Future 2018 Methane Emission Intensities – A Progress Report.

[9] AGA Energy Analysis 2020, June 2020, Understanding Updates to the EPA Inventory of Greenhouse Gas Emissions from Natural Gas Systems.

[10] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018.

[11] Ibid.

[12] Final Supplemental Environmental Impact Statement for the Proposed PSE Tacoma LNG Plant.

[13] NWPCC Methane 2021 Power Plan Workbook.

[14] Ibid 6-18.

The British Columbia upstream emissions loss rate of 0.77% that Cascade is using for Canada sourced natural gas is based on data reported in a recent environmental impact study for the PSE Tacoma LNG plant, Kalama Manufacturing and Export Facility and the 2019 Puget Sound Energy IRP.[15] Also, NWPCC's NGAC applied this data in estimating the upstream emissions loss factor for Canada sourced natural gas in their analysis. The study for the PSE project includes data modeled by a consultant for the Puget Sound Clean Air Agency's review of life cycle GHG emissions for that project.

The emissions loss rates reviewed by Cascade and others above may also vary depending on whether they represent upstream methane emissions alone or if they also include upstream GHG combustion emissions. If the loss rates would only include methane fugitive emissions upstream, considering that those emissions are the majority of GHG emissions that occur upstream in the natural gas value chain as understood through review of the oil and gas industry emissions tables in EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018.[16]

Cascade acknowledges that the Canada and U.S. Rockies upstream emissions loss rates are estimates and may be updated in future as more accurate methods of estimating upstream emissions from the oil and gas industry are realized. The Company will continue to monitor developments and studies in this area to revisit and update the upstream emissions factor and estimation methodologies applied to avoided cost calculation in future IRPs.

[15] Ibid.
[16] Ibid 6-18.

Cascade's Upstream Emissions Factor Calculation

In this section, Cascade demonstrates the upstream emissions calculation. The equations and inputs for calculating upstream emissions and the emissions rate used in the avoided cost calculation are shown and explained below:

$$ER_T = \frac{1\ dekatherm}{10\ therms} * \frac{1\ mmbtu}{1\ dekatherm} * (UER_{CO2e} + CER_{CO2e})$$

And;

$$UER_{CO2e} = UER_{CH4} * GWP_{Methane}$$

And;

$$CER_{CO2e} = EF_{EPA\ Subpart\ NN} / Heating\ Value$$

And;

$$UER_{CH4} = \rho\ methane * \frac{\%\ methane\ in\ natural\ gas}{Heating\ Value} * ULF_{Weighted\ \%}$$

And;

$$ULF_{Weighted\ \%} = (ULF_{US\ Rockies\ \%} * \%\ Cascade\ U.S.Rockies\ Supply) + (ULF_{Canada\ \%} * \%\ Cascade\ Canada\ Supply)$$

Where;

- ER_T = Total emissions rate in CO_2e Metric tons per therm of natural gas delivered, the sum of the upstream emissions rate and the customer end-use emission rate.
- UER_{CO2e} = Upstream emissions rate (emissions estimated to occur upstream of customer receipt) in CO_2e metric tons per MMBtu of natural gas delivered.
- UER_{CH4} = Upstream emissions rate (emissions estimated to occur upstream of customer receipt) in CH_4 metric tons per MMBtu of methane delivered.
- CER_{CO2e} = the customer emission rate, from customer end-use combustion of natural gas delivered, in CO_2e metric tons per MMBtu.
- $GWP_{Methane}$ = 25, the global warming potential (GWP) of methane at 100 years. This GWP value is from Chapter 2, Table 2.14, of IPCC 4th Assessment Report AR4 Climate Change 2007: The Physical Science Basis)[17] to convert methane into CO_2e at 100 year.

[17] IPCC AR4 Climate Change 2007: The Physical Science Basis, Chapter 2.

- $EF_{EPA\ Subpart\ NN}$ = 0.0544 metric tons of CO_2 emitted per the combustion of 1 Mcf of natural gas, an EPA emission factor from 40 CFR Part 98 Subpart NN.[18]
- *Heating Value* = 1.07904 mmbtu per Mcf of natural gas. This is a 2019 average of the heating value of gas supplied to Cascade's distribution system in Washington and was taken from Cascade's 2019 annual GHG emissions report to EPA.[19]
- *ρ methane* = 0.0192 metric tons of methane per 1 Mcf of methane, the density of methane as provided in 40 CFR Part 98 Subpart W.[20]
- *% methane in natural gas* = 93.4%. This value represents an average percentage of methane in natural gas of 93.4% from EPA GHG inventory data and is discussed on page 14 of AGA's June 2020 Energy Analysis Report.[21] Cascade reviewed data from September and October 2020 on Williams', (Northwest Pipeline) website,[22] analyses posted for public review, and confirmed locations where Cascade receives natural gas were in the range of 93.4%.
- $ULF_{Weighted\ \%}$ = the upstream loss factor expressed in percent methane emitted upstream per total methane delivered and is a weighted average of the different methane emission loss factors representing the estimated natural gas that is supplied to Cascade from the U.S. Rockies or Canada.
- $ULF_{US\ Rockies\ \%}$ = 1.0%. This upstream loss factor represents an estimate of the percent of methane lost from infrastructure supplying natural gas from the U.S. Rockies. As discussed in the Upstream Natural Gas Value Chain Emissions section above, Cascade has chosen at this time to use a 1.0% loss rate for gas supplied from the U.S. Rockies.
- $ULF_{Canada\ \%}$ = 0.77%. This upstream loss factor represents an estimate of the percent methane lost from infrastructure supplying natural gas from Canada. As discussed in the Upstream Natural Gas Value Chain Emissions section above, Cascade has chosen at this time to use a 0.77% loss rate for gas supplied from Canada.
- *% Cascade U.S. Rockies Supply* = 35.8% for Cascade's Washington customers, estimated using 2019 gas supply data.
- *% Cascade Canada Supply* = 64.2% for Cascade's Washington customers, estimated using 2019 gas supply data.

[18] e-CFR 40 CFR Part 98 Mandatory Greenhouse Gas Reporting, Subpart NN – Suppliers of Natural Gas and Natural Gas Liquids.
[19] Cascade Natural Gas Corporation Washington 2019 EPA Subpart NN GHG Emission Report.
[20] e-CFR 40 CFR Part 98 Mandatory Greenhouse Gas Reporting, Subpart W – Petroleum and Natural Gas Systems.
[21] Ibid 6-18.
[22] Williams Northwest Pipeline Daily Gas Quality Values website.

Based on the equations and input explained above, Cascade estimated a total emissions rate, ER_T, to be 0.00540 CO_2e metric tons per therm of natural gas delivered and uses this value in avoided cost calculations. Further background on this calculation and spreadsheet used to memorialize this calculation was discussed in a supplemental TAG meeting on October 15, 2020.

As noted in the equations section, Cascade utilizes the 100-year global warming potential (GWP) for methane of 25 per Chapter 2, Table 2.14, of IPCC 4th Assessment Report (AR4) Climate Change 2007: The Physical Science Basis[23] to convert to CO_2e in the upstream emissions rate of UER_{CO2e} calculation. Cascade has chosen to follow EPA's application of GWPs for methane in the agency's Inventory of U.S. Greenhouse Gas Emissions and Sinks at this time. EPA provides explanation on the agency's *Understanding Global Warming Potentials* webpage,[24] explaining the agency is complying with the United Nations Framework Convention on Climate Change (UNFCCC) [Review Practice Guidance[25] published in March 2016] reporting standards. The UNFCCC's guidance instructs GHG inventories to be compiled using the AR4 GWPs.

Cascade acknowledges the IPCC 5th Assessment Report published in 2014 includes 100-year GWPs for methane in the range of about 28-36.[26] The company expects this range may continue to be refined in future. Cascade notes that ICF included some discussion on the uncertainties of the IPCC AR5 GWPs for methane in their report Finding the Facts on Methane Emissions: A Guide to the Literature, published for The National Gas Council in April 2016.[27] The report notes that the AR5 GWPs for methane have not been adopted by all parties and parties using the values appear to choose different GWP values with differing warming feedback impacts and it was not clear to Cascade how others are making choices in applying the different values and how Cascade would accurately apply the feedback impacts. Cascade will continue to monitor and adjust the GWPs used in IRPs as more refinement occurs and as EPA and UNFCCC consider adoption of more recent GWPs into their processes.

Cascade Customer Emissions from Natural Gas Combustion

GHG emissions are generated by Cascade's customers due to combustion of natural gas. Over time, the Company's sales of natural gas have grown to accommodate customers' demand for natural gas, and therefore, GHG emissions have increased from customers' combustion of natural gas. Increased demand is

[23] Ibid 6-20.
[24] EPA - Understanding Global Warming Potentials.
[25] UNFCCC Review Practice Guidance, March 3, 2016.
[26] IPCC AR5 Synthesis Report: Climate Change 2014.
[27] ICF's Finding the Facts on Methane Emissions: A Guide to the Literature.

expected to be due to currently stable natural gas prices and steady economic growth.

The total annual emissions from Cascade's core customers are in the range of about 1.4 million metric tons of CO_2. Emissions from non-core customers have totaled in the range of about 2.5 to 3 times higher than total emissions from core customers, depending on the year and whether customers switch from non-core to core customer arrangements.

Cascade GHG Emissions Reductions

Cascade is not currently subject to any GHG emissions reduction requirements. However, the Company has achieved GHG emissions reductions through economically prudent voluntary efforts. Some of Cascade's GHG emissions reductions have been realized through implementing operational changes and capital projects required through other regulatory requirements. These GHG emissions reductions are discussed in the following section.

1. Fugitive Methane Emissions Reductions

EPA has focused on reducing fugitive methane emissions from the oil and gas sector but has not applied emission reduction requirements specifically to LDCs. Instead, the agency has focused on sponsoring voluntary programs to encourage commitments to reduce methane emissions from LDCs.

a. EPA Natural Gas Star Methane Challenge Program.

Cascade became a Founding Partner of the EPA's Natural Gas Star Methane Challenge Program in March 2016. As a Founding Partner, Cascade has chosen to participate in the program under the Best Management Practice (BMP) Commitment – Excavation Damages within the natural gas distribution sector. The BMP Commitment entails a Partner's commitment to company-wide implementation of BMPs to reduce methane emissions. Involvement in this program also provides a forum for companies to share knowledge on successfully implementing BMPs and methane emissions reductions. During the initial commitment timeframe, Cascade will conduct incident analyses on all excavation damages and report the relevant data to EPA as the agency finalizes the reporting forms.

Specifically, Cascade demonstrates its commitment to this program through implementation of BMPs to promote leak reductions.

Cascade created the position of Public Awareness and Damage Prevention Coordinator in 2018. This position assists in providing community education and outreach opportunities, focusing on damage prevention, and further reducing potential releases of methane from excavation damages. This position also focuses on working with contractors or third parties that are repeat offenders. By identifying and reaching out to these repeat offenders prior to work beginning on their respective project, Cascade expects to see a reduction in excavation damages throughout the Company's service areas.

Additionally, Cascade actively participates in 811, Common Ground Alliance, and damage complaint programs in Washington and Oregon. Cascade continues to explore other voluntary actions which could reduce methane emissions resulting from excavation damage.

Beyond Cascade's commitment to reduce methane emissions from excavation damages, Cascade has completed operational and infrastructure changes to comply with federal requirements which have resulted in lower methane emissions, and therefore lower GHG emissions in the State of Washington. This has mainly been realized through pipeline replacement projects where newer pipeline materials such as polyethylene and steel are used to replace older materials. Since 2012, Cascade has replaced nearly 75 miles of early vintage steel pipe in Washington with new steel or polyethylene pipe, ranging from service lines up to 12-inch mains. Also, Cascade has no unprotected steel pipe and no leak-prone cast iron pipe in its systems.

b. Energy Efficiency Program Greenhouse Gas Emission Reductions

Cascade's conservation programs help reduce GHG emissions by providing incentives to customers for a comprehensive set of prescriptive and custom energy efficiency upgrades designed to streamline their use of natural gas, thus reducing their overall carbon footprint. Space, water heating, and weatherization incentives drive lowered energy consumption and positive energy behavior in customers' homes and businesses. This leads to lowered demand, bill reductions, and overall carbon emission reductions in the communities. Cascade's energy efficiency programs currently save about 40,000 to 80,000 dekatherms annually, about 4,000 to 5,000 metric tons of CO_2/year. More emission reductions will be realized

as the Company's programs mature and continue to grow. Please see Chapter 7, Demand Side Management, for additional details.

In addition to the conservation and efficient use of natural gas, the direct use of this resource can also be a significant source of carbon reduction. Source efficiency is an important consideration when developing programs and policies to achieve meaningful carbon reductions. When natural gas is transported to electric generation facilities which, in turn, transmit electricity for customers' end-uses (e.g., space heating, water heating, cooking, etc.), 50% to 75% of the Btu content of the power is lost when compared to the same end-uses which have been supplied by natural gas. According to the American Gas Association's whitepaper, Dispatching Direct Use: Achieving Greenhouse Gas Reductions with Natural Gas in Homes and Businesses, a typical gas water heater uses half the energy of an electric resistance hot water heater, emits half the CO_2, and costs less than half as much to operate on an annual basis. This opportunity for carbon savings applies to space heating equipment as well.

In fact, EPA recognizes source efficiency as the method utilized when assessing the energy efficiency value of conservation equipment and measures.

It is for these reasons that Cascade has encouraged the direct use of natural gas when paired with strong energy efficiency measures. Accelerating this effort in tandem with the integration of renewable natural gas would be of benefit from both a demand response and a GHG emissions reduction standpoint—a win for the community, Company, and customers.

CO_2 Adder Analyses

Cascade has chosen to model CO_2 adders from a review of the information compiled above for the 2020 IRP. Since there are currently no GHG reduction requirements finalized for LDCs, the Company has chosen the most representative of state and federal GHG policies for modeling potential carbon regulatory impacts on operations and customers.

Although this section is dedicated to CO_2 adder discussion, Cascade also applies environmental adder sensitivity analyses in modeling environmental general impacts of 0%, 20%, and 30%, as well as impacts on timing and quantity of demand side resources, total system costs of candidate portfolio under stochastic

conditions, and timing and quantity of viability of renewable natural gas. For detail and discussion on the application of the adders in the modeling analysis, see Chapter 10, Resource Integration.

1. CO_2 Adders Modeled

Cascade has chosen to use one main CO_2 adder scenario and three sensitivities to model cost impacts from potential future carbon pricing that could apply to customer's usage of natural gas. The new methodologies chosen to model are discussed below. The Company discussed the proposed CO_2 adders and modeling approaches in Technical Advisory Group (TAG) meetings and received no objections.

a. Social Cost of Carbon

Cascade is modeling the SCC as the main carbon adder in its IRP. Cascade is specifically modeling the two and one-half percent discount rate SCC published in the U.S. IWG on the Social Cost of Greenhouse Gases' Social Cost of Carbon. The IWG SCC values based on this discount rate are shown below in Figure 6-1, sourced from the IWG's publication Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.[28] Cascade is following WUTC guidance as outlined in Docket U-190730 by using the SCC with a two and one-half percent discount rate, and by scaling it to real dollars by using the GDP price index as published by the Bureau of Economic Analysis.

[28] *See* Page 4 of https://www.utc.wa.gov/regulatedIndustries/utilities/Documents/Technical%20Support%20Document%20Social%20Cost%20of%20Carbon%20August%202016.pdf

Figure 6-1: Social Cost of CO_2, 2010-2050 (in 2007 dollars per metric ton of CO_2)

Year	5% Average	3% Average	2.5% Average	High Impact (95th Pct at 3%)
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

b. Cap and Trade

Cascade is modeling its cap and trade forecast after the California Energy Commission's Integrated Energy Policy Report (IERP) 2019 Preliminary GHG Allowance Price Projection. Cascade projects this to equate to a scaling carbon emissions cost, starting at $24.70/metric ton in 2021 and capping at $61.50/metric ton from 2030 onward. This provides an example of cap and trade program approach to carbon pricing, occurring in the nearby state of California and which has been in place for several years.

c. U.S. House of Representatives Market Choice Act

Cascade is modeling the Market Choice bill as a CO_2 adder sensitivity since it represents recent carbon legislation proposed at the federal level in the past couple years. This bill includes provisions for addressing GHGs, including a carbon tax for combustion of fossil fuels. The bill proposes to apply an initial tax of $24/ton of CO_2 equivalent emitted from fossil fuel combustion starting in 2020 which would escalate annually by two percent plus an inflationary

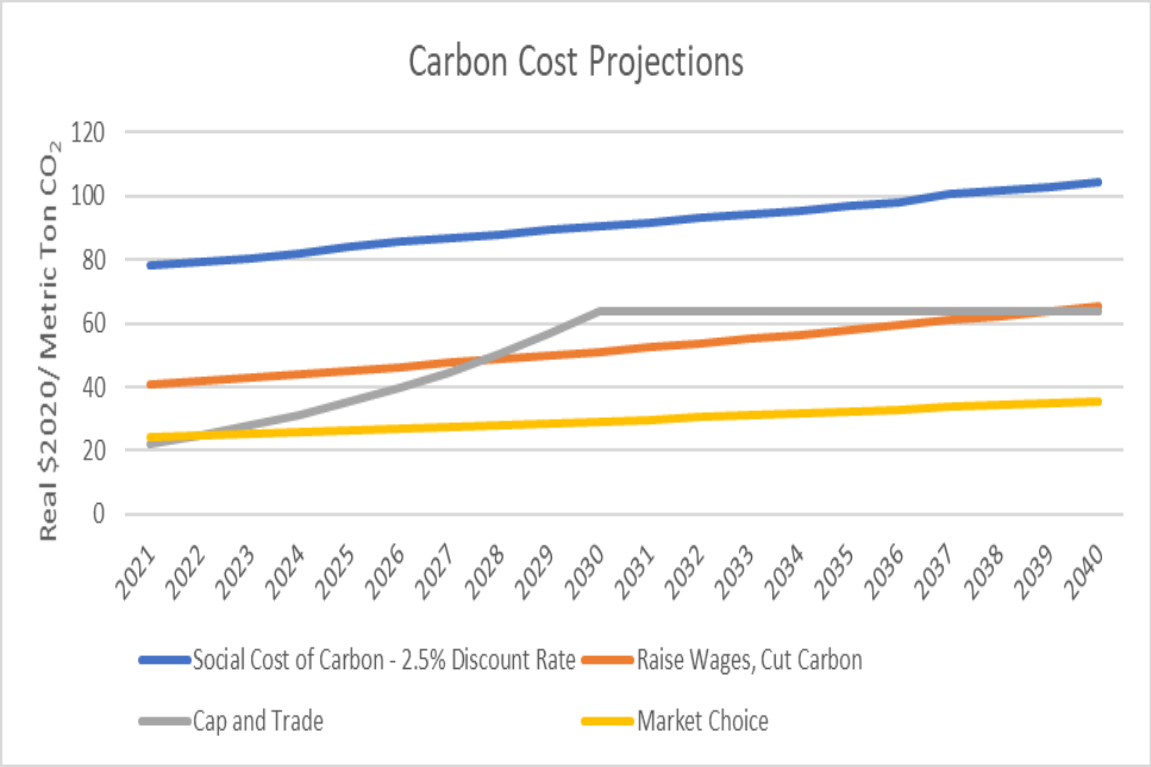
adjustment. Affected emissions would be quantified annually to determine if annual caps identified in the bill are met. If GHG emissions caps are not met, the tax would increase an additional $2/year. Cascade models the two percent annual increase, plus inflationary adjustment, in this IRP analysis, but assumes GHG emissions caps are met and no additional penalties would be applied to the carbon tax.

d. U.S. House of Representatives Raise Wages, Cut Carbon Act (HR 3966)

Cascade is modeling the Raise Wages, Cut Carbon Act as a CO_2 adder sensitivity since it represents the most current carbon legislation proposed at the Federal level. This bill would apply a tax to importers of fossil fuels and fluorinated greenhouse gases. The tax would start at $40/metric ton of CO_2 equivalent emitted and increase 2.5%/year plus inflation. Cascade models the 2.5% annual increase, plus inflationary adjustment, in this IRP analysis, and assumes GHG emissions caps are met and no additional penalties would be applied to the carbon tax.

Figure 6-2 illustrates all the CO_2 adder values discussed above over an approximate 20-year period.

Figure 6-2: Carbon Cost Projections



Conclusion

There are currently no GHG emissions reduction requirements that have been finalized for LDCs. Although there are no applicable GHG reduction requirements for LDCs, Cascade has been voluntarily reducing fugitive methane emissions and reducing GHG emissions from customer combustion of natural gas through implementation of energy efficiency and conservation programs.

The Company is exploring renewable natural gas opportunities to comply with new requirements for the company to establish prudently acquired renewable natural gas projects or environmental attributes accordingly with HB 1257. Implementing renewable gas into Cascade's system would serve to reduce GHG emissions from the natural gas supply chain. Further discussion of renewable natural gas can be found in Chapter 8, Renewable Natural Gas.

Cascade will review the NWPCC's next Power Plan to inform the Company on regional energy and GHG emissions analyses, cost impacts and potential future

regional policy development. The Company will continue to monitor and be engaged in Cascade's service area community-driven efforts in adopting GHG emission reduction targets. As state and federal GHG emissions policy and regulatory activity are introduced, Cascade will monitor to consider and incorporate these potential impacts into the Company's IRP process.

Chapter 7

Demand Side Management

Overview

Key Points

- Cascade projects 45.22 million therms of energy efficiency in Washington over the 20-year planning horizon.
- This plan is informed by Cascade's stand-alone Conservation Advisory Group (CAG).
- Cascade examines the Technical, Achievable Technical and Achievable Economic Potential of DSM programs through the LoadMAP model.
- LoadMAP generates targets used within the Conservation Plan, based on unique service territory therm savings potential.
- Programs are based on incentives, research, information, outreach, and engagement of key parties – and are designed and implemented to achieve DSM savings targets.

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

This Chapter presents the methodology used to determine the Company's DSM supply curve for the 20-year planning period, the Company's annual savings targets, and a narrative DSM goal achievement.

Chapter 6 considers state and federal policy initiatives addressing carbon mitigation that may increase the cost of natural gas service, thus increasing the amount of cost-effective DSM.

Chapter 5 outlines the avoided cost of natural gas which is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost serves to represent the cost that could be avoided through energy efficiency programs. The average avoided cost per therm increased from ~$0.32 in 2018 to ~$0.57 in 2020, representing an average increase of ~78%. Further, the long-term discount rate decreased from 4.43% to 3.40%, aligned with this IRP's models is tied to the average 30-year mortgage rate; a lower discount rate combined with higher avoided costs increases efficiency potential.

The Company's energy efficiency (or demand side) resources are acquired from individual customers in the form of unused energy. This Chapter is responsive to the Washington Utilities and Transportation Commission's (WUTC or Commission) requirement that natural gas utilities consider cost-effective DSM resources in their energy portfolio on an equal and comparable basis with supply side resources.

In the natural gas industry, DSM resources are energy efficiency measures that include, but are not limited to: ceiling, wall, and floor insulation; higher efficiency natural gas appliances, insulated windows and doors, ventilation heat recovery systems and other commercial/industrial equipment. By influencing customers through energy efficiency outreach to reduce their individual demand for gas, Cascade can reduce the need to purchase additional gas supplies, displace or delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcements on the Company's distribution system.

By incentivizing efficiency from customers versus conservation to reduce overall system load, the Company can more accurately track load reduction and does not solely depend on customer behavioral change. Energy conservation involves using less energy by adjusting behaviors and habits. Energy efficiency, on the other hand, involves using technology that requires less energy to perform the same function.

Cascade targets the saving of approximately 57 million therms systemwide over the 20-year planning horizon; 45 million therms in Washington and 12 million therms in Oregon.

DSM Resources

There are two basic types of demand side resources: base load resources and weather dependent resources. Base load resources offset gas supply requirements throughout the year, regardless of weather conditions. Base load DSM resources include equipment such as high-efficiency water heaters and higher efficiency cooking equipment. Weather dependent 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 and will provide little to no savings in the summer months. These types of weather dependent measures for space heating offset some peaking or seasonal gas supply resources and are typically more expensive than base load supplies (such as water heating).

Energy efficiency is delivered to Cascade customers through a portfolio of services in Washington and Oregon.

Cascade's Washington Energy Efficiency Program

Cascade delivers energy efficiency services to its Washington core customers through the Company's Energy Efficiency (EE) department for the Residential program and a third-party implementer, TRC Companies, for Commercial/Industrial (C/I). Cascade also is a funding member of the Northwest Energy Efficiency Alliance (NEEA) which provides additional efficiency savings by joining with other utilities to promote market transformation.

NEEA is a consortium of funding utilities and energy efficiency stakeholders:

- Natural gas market transformation efforts have longstanding effects on future therm saving opportunities.
- The goal is to increase market adoption of energy efficient natural gas products and practices in the future.

Cascade manages the following Washington residential incentive programs:

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

TRC Companies manage the following Washington C/I programs on Cascade's behalf:

- Commercial (Existing and New Construction)
    - Retail, offices, schools, groceries & other associated market segments
        - Weatherization, controls, HVAC & water heating equipment
- Industrial & Agriculture (core customers)
    - Manufacturing facilities, greenhouses
        - Process improvements, HVAC & water heating equipment, operations and maintenance

The Company is committed to meeting 100 percent of its conservation target. Cascade files an annual conservation plan by December 1 of each year, and files an annual conservation achievement report by June 1 each year. The Conservation Plan serves to provide greater specificity for achieving energy efficiency and conservation where possible and will serve as a biennial report from 2021 forward.

Cascade's Oregon Energy Efficiency Program

Energy Efficiency and conservation offerings for the Company's Oregon customers are offered through the Energy Trust of Oregon with program planning developed through the Cascade Oregon IRP cycle. (This subsection regarding Oregon DSM is included for informational purposes only to depict different program delivery in Oregon, although with similar methodologies.)

Energy Trust administers the following EE programs in Oregon on Cascade's behalf:

- Residential (Existing and New Home Construction)
    - Single family, moderate income, manufactured homes
        - Weatherization, Heating Ventilation and Air Conditioning (HVAC) & water heating equipment
- Commercial (Existing, New and Multifamily)
    - Retail, offices, schools, groceries & other associated market segments

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

Conservation Potential Assessment

Cascade now performs a Conservation Potential Assessment (CPA) biennially. A CPA consists of estimates of potential reductions in annual energy usage for natural gas customers in the Cascade service territory from energy efficiency. This process is outsourced as a means to maintain impartial findings.

Cascade employs a third-party firm, Applied Energy Group (AEG), for the development of its CPA. AEG is an industry leader who developed Cascades' 2018 CPA and who works with other regional utilities on their assessments. The conservation potential for this IRP is calculated through AEG's forecasting model.

Load Management Analysis and Planning Tool (LoadMAP)

AEG's LoadMAP model is separated into three results modules:

- LoadMAP Baseline takes a units-based approach to stock turnover, tracking equipment installations in each year.

- LoadMAP Potential forecasting module calculates potential savings relative to the baseline projection developed in the previous module. This model begins with the detailed stock accounting results from the LoadMAP Baseline analysis but converts all measures to single line-items for transparency and ease of review.

- LoadMAP Results summarizes modeling outputs from the two prior modules at both a high level and in measure-by-measure detail. This module does not perform any potential estimation calculations but is instead intended to serve as a centralized location for reviewing model outputs and summarizing results.

The model then forecasts efficiency potential in terms of Technical Potential, Achievable Technical Potential, Achievable Economic Utility Cost Test (UCT) Potential, and Achievable Economic Total Resource Cost (TRC) Potential. The end result provides Cascade with a full twenty-year forecast and the tools to develop a two-year action plan for Cascade stakeholders.

AEG's forecasting term definitions for the CPA and LoadMAP:[1]

> ***"Baseline Projection**: Projection of baseline energy consumption under a naturally occurring efficiency case, described at the end-use level. The LoadMAP models were first aligned with actual sales and Cascade's official, weather-normalized econometric forecast [per Section 3, Demand Forecast] and then varied to include the impacts of future federal standards, ongoing impacts of the 2015 Washington State Energy Code on new construction, and future technology purchasing decisions.*
>
> ***"Technical Potential** is defined as the theoretical upper limit of EE potential. It assumes customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option.*
>
> ***"Achievable Technical** Potential refines technical potential by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that affect market penetration of conservation measures. The customer adoption rates used in this study were the ramp rates developed for the Northwest Power & Conservation Council's Seventh Plan based on the electric-utility model, tailored for use in natural gas EE programs.*
>
> ***"UCT Achievable Economic** Potential further refines achievable technical potential by applying an economic cost-effectiveness screen. In this analysis, primary cost-effectiveness is measured by the UCT, which assesses cost-effectiveness from the utility's perspective. This test compares lifetime energy benefits to the costs of delivering the measure through a utility program, excluding monetized non-energy impacts. These costs are the incentive, as a percent of incremental cost of the given efficiency measure, relative to the relevant baseline course of action (e.g. federal standard for lost opportunity and no action for retrofits), plus any administrative costs that are incurred by the program to deliver and implement the measure.*

Note: The cost-effectiveness threshold at 0.9 functions as a proxy for cost effectiveness measures seen as attractive but not cost-effective e.g. February 1, 2021, 0.30 windows are being offered at a UCT value of 0.75. This example demonstrates CNGC's response to market forces that require consideration of all portfolio possibilities.

> ***"TRC Achievable Economic** Potential is similar to UCT achievable economic potential in that it refines achievable technical potential through cost-effectiveness analysis. The TRC test assesses cost-effectiveness from a combined utility and participant perspective. As such, this test includes full*

[1] 2018 IRP, Appendix D

measure costs but also includes non-energy impacts realized by the customer if quantifiable and monetized."

Energy Efficiency 20-Year Potential Forecast

This IRP provides Cascade's Washington service territory therm savings potential as calculated by AEG in Phase 1 of the 2020 CPA. It is intended to add an improved level of transparency and granularity to the Company's planning processes from previous iterations.

AEG's updates for Phase I of Cascade's CPA included revised:

- Sector and segment energy baseline totals using 2019 billing data from CNGC
- Saturations (presence of equipment) based on updated billing data
- Residential annual equipment consumption data based on most recent DOE data
- Commercial end use intensities to align with Commercial Building Stock Assessment 2019
- Measure achievability ramp rates to improve model alignment with achieved program results
- Avoided costs to be consistent with Chapter 5 and include the social cost of carbon adder
- Model engine files to reflect the current AEG versions
- Reviewed and updated incentives for measures currently active in CNGC programs

A Phase 2 CPA will launch in January 2021 and will provide greater granularity on measure assumptions based off of 2020 program results. This will bring energy efficiency program models in line with natural gas regional protocols creating a nuanced approach to natural gas forecasting that works in parallel with the electric-focused Northwest Power and Conservation Council (NWPCC) 2021 Power Plan. At the completion of Phase 2 the Company will file the CPA with the Commission in early summer of 2021.

Phase 2 will cover:

- Calibration to 2020 calendar year actuals
- Comprehensive updates to all measure characterizations, including new and emerging measures identified during phase I
- Revisit electric NWPCC Power Plan participation rates in the context of gas programs
- Update non-energy impacts (NEIs) and values and evaluate potential under the UCT and TRC as well as the Resource Value test, which will be available pending future WUTC direction.
- Pending scope/budget addition: Characterize measures and estimate energy efficiency potential specific to Cascade's low-income customer

Please see Cascade conservation and energy efficiency climate zones used for program planning and evaluation within the CPA in Figure 13-14 in Chapter 13, Glossary and Maps.

The efficiency potential forecast in this IRP is calculated through the AEG LoadMAP model. The forecast is categorized by the three customer classes: Residential, Commercial and Industrial. The forecast for each class includes individual savings assumptions, market segmentations, and end uses (weather dependent measures have different residential savings potential by climate zone). The demand planning assumptions were provided by Cascade's Resource Planning Team (RPT) and, thereafter, the efficiency potential forecast outcome was delivered to the RPT for integration into the IRP demand forecast model.

> *"Load Management Analysis and Planning (LoadMAP™) tool was developed in 2007 and was first used for the EPRI National Potential Study. Since that time, LoadMAP has been used to develop end-use forecasts and perform dozens of energy efficiency (EE) potential studies. The LoadMAP model provides forecasts of energy use by sector, segment, end use and technology for existing and new buildings. It can also be used to isolate and estimate savings from DSM measures and programs. LoadMAP was developed by Global Energy Partners, LLC (GEP) under the direction of Ingrid Rohmund. EnerNOC acquired GEP and the LoadMAP model in 2011. In June 2014, AEG acquired EnerNOC's Utility Solutions Consulting Group and the LoadMAP model. AEG supports ongoing enhancements to the model."*[2]

This modeling tool provides the ability to run multiple scenarios and re-calculate potential savings based on variable inputs, such as the customer and demand forecasts, IRP long term discount rate, transmission loss rate and avoided costs. Recent annual program performance and measure data collected through energy efficiency programs are incorporated to establish incremental costs reflective of Cascade's service territory. This model provides transparency to all assumptions and calculations for estimating market potential.

Avoided costs are a key input to the potential model. They are variable costs for a unit of energy, or capacity, or both that are avoided through energy efficiency adoption. There is a direct correlation between variable energy costs and savings potential. The higher the variable energy costs, the greater the savings potential when those costs are avoided through energy efficiency. These per therm avoided costs flow through the forecast and are the primary factor in calculating efficiency potential.

The economic merits of the portfolio are gauged through standard industry cost-effectiveness tests. Each test compares the benefits of the energy efficiency savings to their costs defined in terms of net present value of future cash flows.

[2] 2018 IRP, Appendix D

While Technical and Achievable Technical potential are both theoretical limits to efficiency savings, Achievable Economic potential embodies a set of assumptions about decisions consumers will make regarding the cost and benefits of the equipment they purchase. Based on Northwest regional standard practice, Cascade's Energy Efficiency planning adopts the Achievable Economic potential to set goals under an array of possible future conditions.

Cascade applies the UCT for evaluating the Benefit Cost ratio across its programs. The Benefits in the UCT calculation are the avoided energy capacity costs for the lifetime of the measure; the Costs in this test are the program administrator's incentive costs and administrative costs.

In addition, LoadMAP concurrently runs all scenarios under the TRC for comparison. The cumulative long-term potential under the UCT remains higher at the programmatic level than the TRC, whereas this may not always be the case in the short-term.

Washington Market Segmentation & End Use

An important first step in calculating Cascade's energy efficiency potential estimates is to establish baseline energy usage characteristics and disaggregate the market by sector, segment, and end use.

The Residential market has three Climate Zone segments for Single family and some Multi Family housing stock, resulting in six market segments.

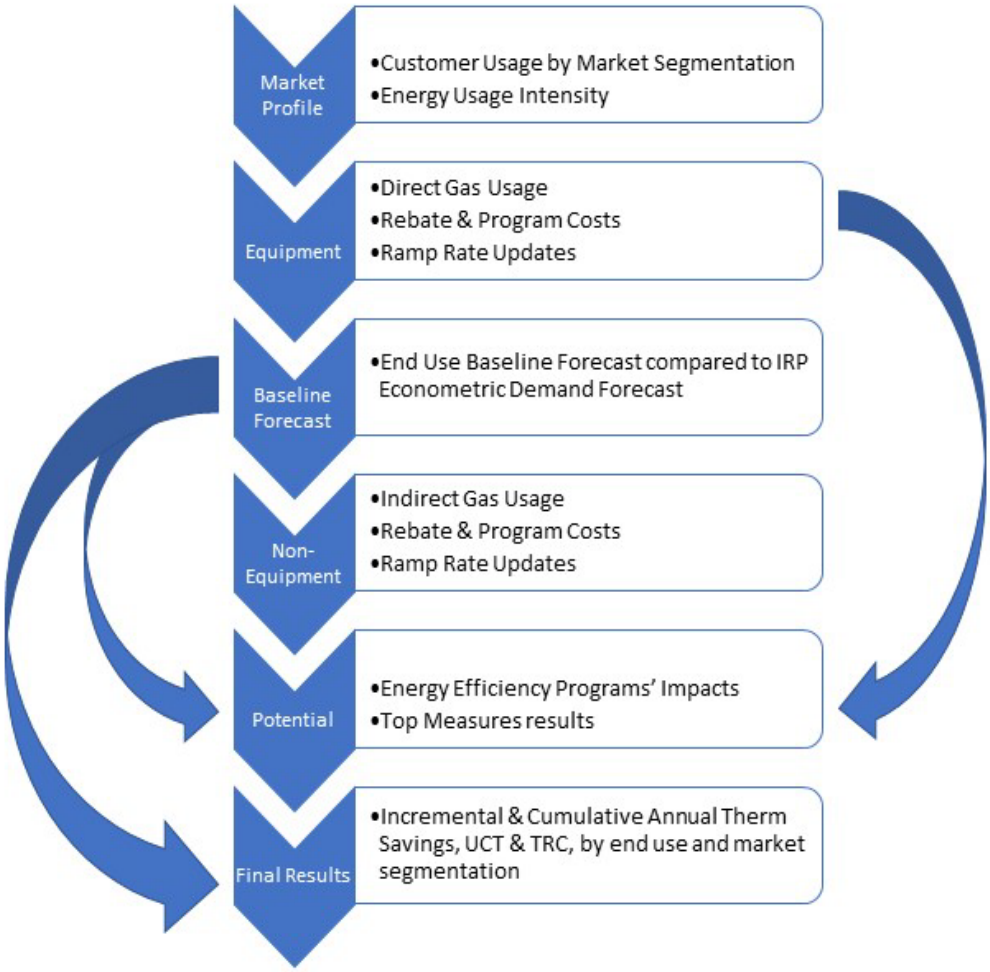
Commercial market segmentation includes: Office, Retail, Restaurant, Grocery, Education, Healthcare, Lodging, Warehouse, and a "Miscellaneous" category.

Industrial market is segmented by: Food Processing, Agriculture, Primary Metals, Stone/ Clay/ Glass, Petroleum, Paper & Printing, Instruments, Wood & Lumber Products, and an "Other" category.

End use categories include: Space Heating, Water Heating, Secondary Heating, Food Preparation, Appliances, Process Heating, and miscellaneous. All of these are ultimately categorized into baseline and peak load.

Figure 7-1 illustrates the LoadMAP efficiency potential process.

Figure 7-1: Savings Potential Process in LoadMAP



There are six separate workbooks that make up the full DSM forecast for each customer class. These all follow the same order of operation, starting with the Market Profile, which feeds into the Equipment workbook. The Equipment then feeds into the Baseline which feeds into Non-Equipment. When running the Potential model, the Equipment, Baseline, and Non-Equipment are all imported. The Final results import the Potential results and the Baseline.

AEG also provides advice on how to update ramp rates based on the NWPCC methodology and industry best practices.

As part of Phase 1 of the 2020 CPA, AEG updated ramp rates for measures within the Residential Program where appropriate, allowing for select measures to move forward

more quickly along the NWPCC's ramp rates than initially anticipated. These include furnaces and insulation measures.

For example, the 2019 achievement for furnace savings is very close to the 2023 forecast. This demonstrates the adaptiveness of the model because the Company can intuitively update its progression along the ramp rates as appropriate. Figure 7-2 provides residential furnace ramp rate potential.

Figure 7-2: Residential Furnace ramp rate potential

Measure Category	CNGC 2019 Achievement	LoadMAP UCT Incremental Savings		
		2021	2022	2023
Furnace	170,680	144,883	149,666	171,801

The participation forecast is a function of the ramp rate and unit turnover from the baseline. In 2021, LoadMAP predicts 13,495 units will be retired in Cascade's Washington market, the majority of which could be incentivized as high-efficiency units (the baseline assumes some customers already buy higher efficiency units without program intervention). The ramp rate states that 32% of the available customers in 2021 will participate, which comes out to 3,409 units. Savings per unit vary by segment based on their base consumption, but run between 30-48 therms/year, depending on climate zone and segment. This type of analysis is repeated across all measures and programs to develop potential savings.

Progress to Plan

The Company's DSM efforts for this cycle and associated incorporation into the IRP provides context on the service territory current potential as calculated by AEG in Phase 1 of the 2020 CPA.

Company therm savings achievements for the past four IRP's compared to the 2020 IRP are in Figure 7-3. Totals for 2020 accomplishments will not be available until the annual report is filed in June 2021. The *Difference* column represents the percent change from goal to actual and the *Growth* column represents the percent change from one biennium IRP to the next.

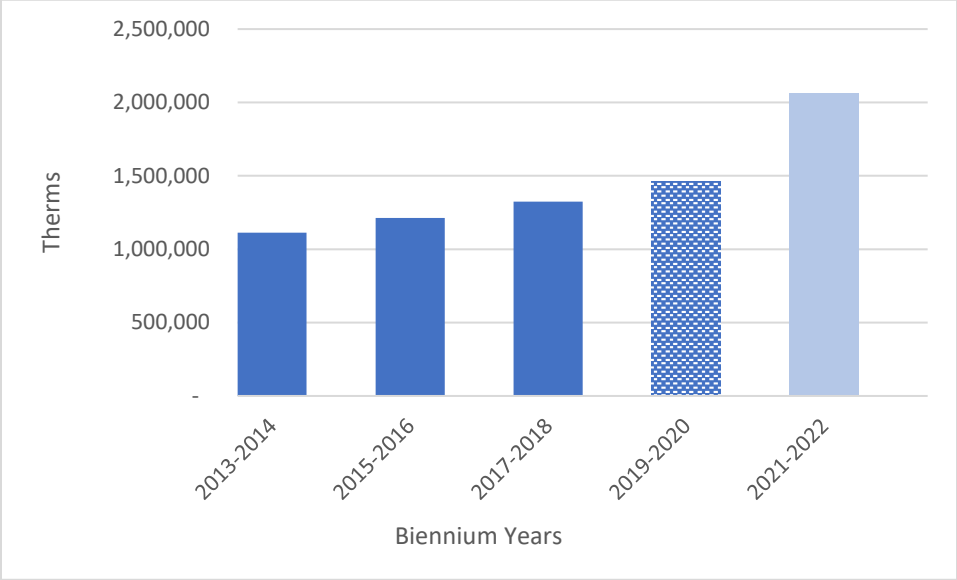
Figure 7-3: Historical IRP Goal to Actual Therm Accomplishments

Years	Biennium	Goals	Actuals	Difference	Growth
2013	**2012 IRP**	1,076,661	1,113,046	**3%**	**-9%**
2014					
2015	**2014 IRP[1]**	1,496,969	1,213,591	**-19%**	**9%**
2016					
2017	**2016 IRP**	1,456,143	1,324,030	**-9%**	**9%**
2018					
2019	**2018 IRP**	1,419,636	**1,463,165[2]**	**3%**	***11%***
2020					
2021	**2020 IRP**	2,063,892	**TBD**	**TBD**	***45%***
2022					

[1]2014 goals were not acknowledged by the WUTC
[2]This number is year to date and subject to final reporting for 2020, which occurs by June 1, 2021

Figure 7-4 shows the actual historical performance and short-term biennium forecast.

Figure 7-4: Incremental Portfolio Biennium Actuals + Forecast



Nexant

As the Company moves into 2021, the "iENERGY DSM Central" software product from Nexant Inc. remains Cascade's tool for processing residential and low income (LI) projects and assisting with management of the TA program. In 2018 the Company implemented a joint effort to design an interim solution to internal eM&V (evaluation, Measurement, and Verification) on the Nexant software platform. For the software design,

development and testing cycles, Nexant required Cascade to serve as thought leaders (as beta testers) during the development process, helping to shape the capabilities of the software. Once fully functional, the product should allow the Company access to advanced reporting through limited internal measurement and verification to develop plans on areas to concentrate efforts. While it will not take the place of external EM&V it does allow for some independent verification of savings.

Low Income

Cascade is committed to increasing participation from Community Action Agencies to serve more customers through the Company's Weatherization Incentive Program (WIP) and Enhanced Weatherization Incentive Program (E-WIP).

In Phase II of the CPA, AEG will work with Cascade to develop a suitable scope to characterize the "low-income" demographic for the purpose of better understanding customer end use and to establish better alignment between LI and Residential program potential. AEG will primarily rely on two data sources to inform the LI analysis.

1. The American Community Survey will be used to estimate the share of Cascade's residential customers that fall above and below the defined low-income threshold. These percentages will be used to apportion Cascade's total residential customer population into these two groups within the LoadMAP model.

2. The 2016-2017 Residential Building Stock Assessment (RBSA) will be used to inform differences in building characteristics (e.g., home size, number of water fixtures, existing insulation levels), equipment efficiency, and saturations of energy efficient technologies for homes above and below the defined low-income threshold. This information will allow AEG to develop separate market profiles for, and more accurately assess, the remaining energy efficiency potential of low-income homes.

AEG will update the existing LoadMAP segmentation to separate LI and non-LI residential customers in each of Cascade's climate zones; base-year market profiles will be developed for each of the segments, beginning with the market profiles from Phase 1 of the current CPA, and on the results of the RBSA analysis as well as actual customer consumption.

The Company also expects the support of the agencies and their outreach efforts to be increased to local communities to reach those customers who have yet to engage in the Energy Efficiency Incentive Programs (EEIP). Cascade will also take the opportunity to partner with other utilities, and community programs, as appropriate and available, to promote a more widely understood goal toward high-efficiency uptake and energy conservation in its service territory.

Budget to Plan

Cascade set an administrative budget to plan and operate programs under the avoided costs shown in Appendix H. This budget currently estimates a 70/30 ratio of Direct Benefit to Customer (DBtC) compared to program costs. Since therm savings offset the costs of administrative investment, the greater the achievement, the more cost-effective the programs. See Figure 7-5 for the goals and budgets for 2021 and 2022 (rounded to the nearest dollar) for reference. These will be used in development of the 2021 Conservation Plan.

Figure 7-5: Program Goals & Budgets at a Glance 2021 & 2022

	Calendar Year 2021				Calendar Year 2022			
	Residential	C/I	Low Income	Total	Residential	C/I	Low Income	Total
Admin Budget[1]	$1,066,042	$1,436,858	$59,900[3]	$2,562,800	$1,110,764	$1,494,332	$61,697	$2,666,793
Therm Targets[2]	471,164	578,483	12,180	1,061,827	504,604	509,641	13,000	1,027,245
NEEA Natural Gas Market Transformation				$127,663				$183,025
Regional Technical Forum				$31,400				$31,400
Conservation Potential Assessment				$98,386				

[1] *Note budgets in this table are estimates and refer to administrative costs for program implementation, not rebate payments*
[2] *Therm targets from this graph have been developed through LoadMAP. Calendar Year 2022 targets will be revised through the 2022 Biennial Conservation Plan*
[3] *Represents only Cascade staff salary and outreach costs associated with weatherization program delivery that are not part of payments to agencies*

LoadMAP generated targets are acknowledged in the Conservation Plan and programs are managed to ensure cost effectiveness is maintained.

Energy Efficiency Programs Forecasted Savings

Cascade utilizes the UCT to measure the program's cost effectiveness. The UCT Test is the optimal vehicle for valuation of these measures since it is a straightforward and clean calculation of the utility's investment in DSM and does not penalize customers for making independent determinations regarding the cost-benefit of an energy efficiency upgrade. The UCT instead treats the rebate from utility run natural gas efficiency programs as a leveraged partnership that drives positive market change and the installation of measures with the potential for long-lived and deeper energy savings.

Figure 7-6 shows the residential, commercial, industrial cumulative DSM forecast by Technical, Achievable Technical and both UCT/TRC Achievable Economic Potentials.

Figure 7-6: Cumulative Residential, Commercial, Industrial Potential Forecasts

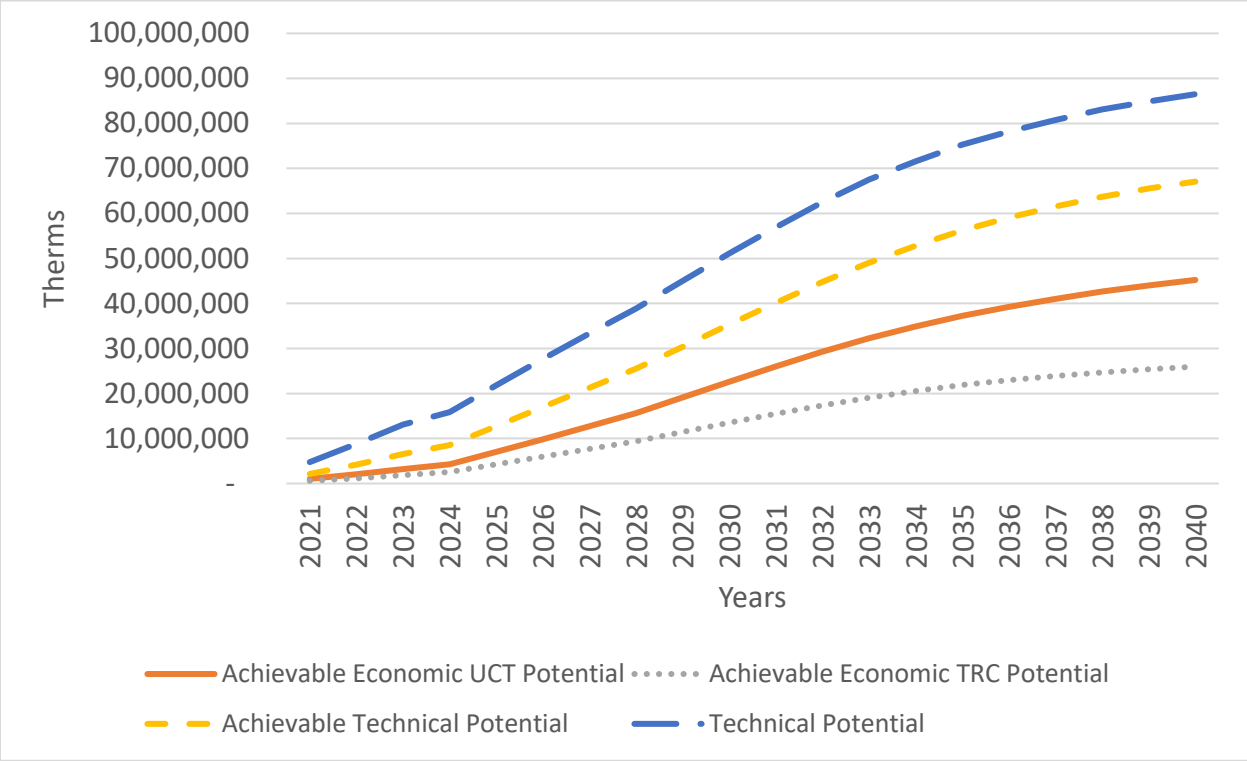


Figure 7-7 shows cumulative savings potential across programs through 2040.

Figure 7-7: DSM Cumulative Forecast by Program

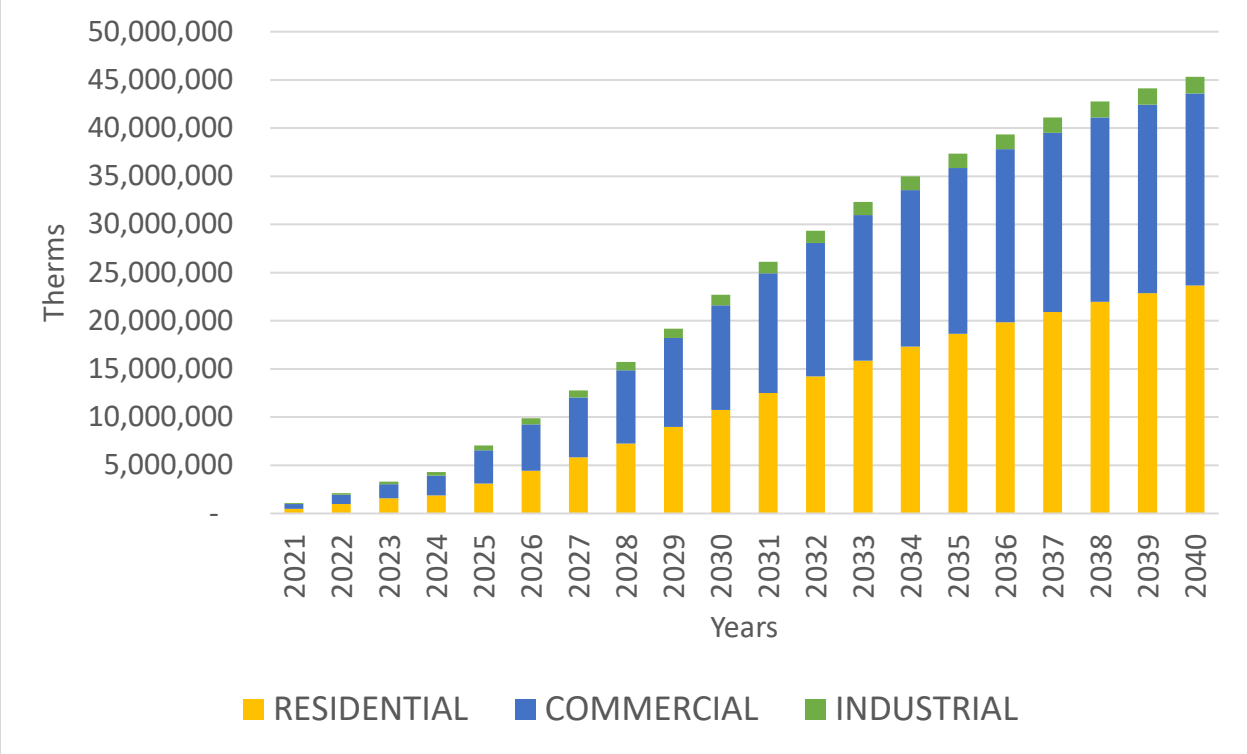
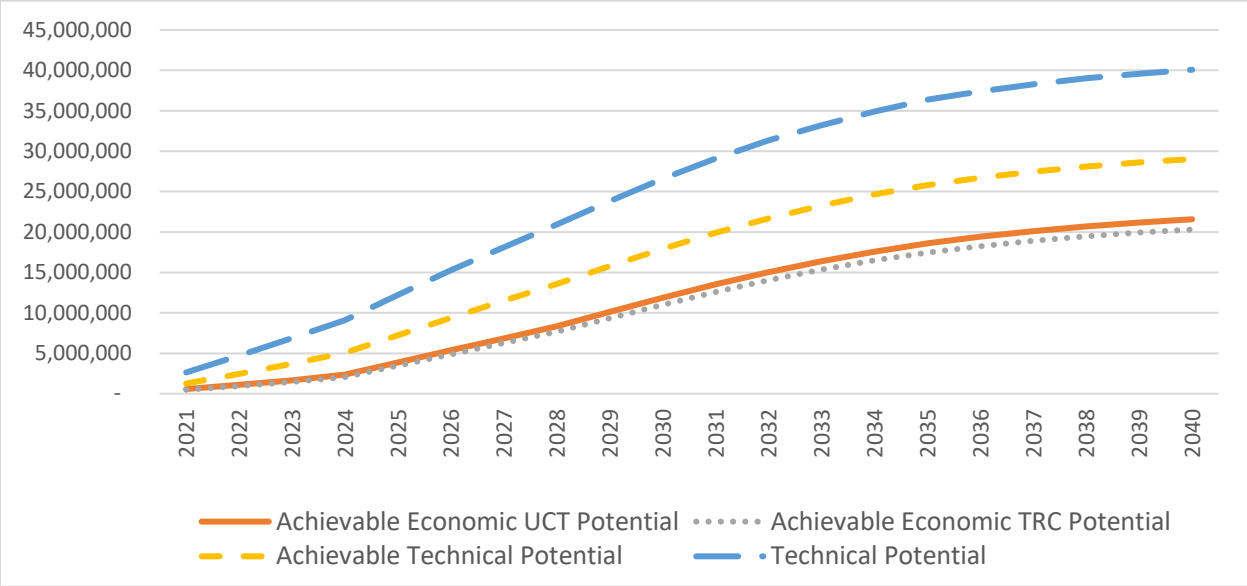


Figure 7-8 shows the C/I cumulative DSM forecast by Technical, Achievable Technical and both UCT/TRC Achievable Economic Potentials for the base case.

Figure 7-8: Cumulative Commercial & Industrial Forecasts



Figures 7-9, 7-10, and 7-11 show the top 10 measures by sector with the most potential for 2021. Top ten measures account for more than 90% of all potential across programs.

Figure 7-9 shows 2021 top ten UCT measures for Residential

Figure 7-9: 2021 Top Ten UCT Residential Measures

Rank	Measure	2021 Savings (therms)	% of Total Savings
1	Natural Gas - Furnace - Direct Fuel	111,535	25.3%
2	Natural Gas - Insulation - Infiltration Control (Air Sealing)	83,388	18.9%
3	Natural Gas - Insulation - Ceiling, Installation	74,668	17.0%
4	Natural Gas - Water Heater <= 55 gal.	42,423	9.6%
5	Natural Gas - Doors - Storm and Thermal	37,375	8.5%
6	Natural Gas - ENERGY STAR Connected Thermostat	18,167	4.1%
7	Natural Gas - Built Green homes	16,016	3.6%
8	Natural Gas - Fireplace	10,424	2.4%
9	Natural Gas - Water Heater > 55 gal.	7,537	1.7%
10	Natural Gas - Ducting - Repair and Sealing	7,332	1.7%

Figure 7-10 shows 2021 top ten UCT measures for Commercial

Figure 7-10: 2021 Top Ten UCT Commercial Measures

Rank	Measure	2021 Savings (therms)	% of Total Savings
1	Boiler	152,831	29.7%
2	Insulation - Roof/Ceiling	38,017	7.4%
3	Gas Boiler - Insulate Steam Lines/Condensate Tank	29,847	5.8%
4	Gas Furnace - Maintenance	26,241	5.1%
5	Fryer	21,815	4.2%
6	Insulation - Wall Cavity	20,422	4.0%
7	Water Heater	20,098	3.9%
8	Gas Boiler - Insulate Hot Water Lines	19,943	3.9%
9	HVAC - Shut Off Damper	19,213	3.7%
10	Gas Boiler - High Turndown	18,533	3.6%

Figure 7-11 shows 2021 top ten UCT measures for Industrial

Figure 7-11: 2021 Top Ten UCT Industrial Measures

Rank	Measure	2021 Savings (therms)	% of Total Savings
1	Strategic Energy Management	18,870	23.7%
2	Retrocommissioning	16,055	20.2%
3	Gas Boiler - Hot Water Reset	9,180	11.5%
4	Gas Boiler - Stack Economizer	6,218	7.8%
5	Gas Boiler - High Turndown	5,251	6.6%
6	Boiler	5,111	6.4%
7	Insulation - Roof/Ceiling	3,851	4.8%
8	Gas Boiler - Maintenance	3,614	4.5%
9	Insulation - Wall Cavity	2,991	3.8%
10	Unit Heater	2,774	3.5%

Based on the Company's experience, legislative trends, work with AEG, and current technologies, the EE team updated key measure assumptions and added new measure permutations in Phase 1 of the 2020 CPA. The rest of the measures in LoadMAP will be updated in Phase 2, these measures may include:

Commercial:

- Furnaces
  - C/I: add second unit tier 97% AFUE
- C/I Boilers: Tier at 86% AFUE (lower incentives, lower therm savings) and a tier at 94% (higher incentives, higher therms)
- Commercial tankless water heaters
  - Updating savings assumptions

Residential:

- Furnaces:
  - Rebate for Furnace tune-ups with combustion safety testing
    - Furnace filter replacement pilot program, potential microbial filter for increased indoor health
- Windows – add 2nd tier to support efficient window installs
  - Windows: two tiers, $5/sq. ft. for U Factor 0.30 and $7/sq. ft. for U Factor 0.27
  - Windows: Remove "single pane" condition; research alternative condition to allow incentivization for old, aluminum frame double pane windows
- Advanced new construction (ENERGY STAR®, Built Green© update ramp rate)
  - Incentive tier for 4 & 5 Star Built Green, potentially remove 3 star rebate eligibility due to code changes
- Residential Multi Family combination units
- Insulation: $1/sq. ft. for all insulation: wall, floor and attic/roof/ceiling
- Remove residential tankless tiers
  - 5.4% are 0.87 UEF; set all rebates to 0.91 UEF

Some of the measures initially deemed cost effective by AEG are program offerings new to the Company. Further research is needed to determine whether the cost-effectiveness would be negatively affected by several technical and operational factors driving up costs. For example, the Solar Water Heater was shown cost effective with a rebate set close to $300. However, upon further investigation into the technology's prices and availability in the Company's service territory, several barriers to uptake were determined. Current installation costs approach $20,000 and few, if any, Trade Allies (TA) offer the equipment to customers, with inconsistent manufacturer support and documentation. With these issues identified, after the initial run the Company updated the measure's ramp rate by shifting it three years into the future. This allows for product maturity while awaiting market transformation efforts including those spearheaded by the Northwest Energy Efficiency Alliance (NEEA).

Further details around new measure inclusion and research are available in the 2021 Conservation Plan.

The Company develops its rebate offerings with the objectives to:

1. Maximize the inclusiveness of viable, industry-acknowledged conservation measures.
2. Set incentive levels as meaningful price signals to consumers to upgrade to high-efficiency natural gas equipment and energy saving measures.
3. Remain cost effective at the Company's most recently acknowledged avoided costs.

Cascade set an administrative budget to plan and operate programs under the avoided costs shown in Appendix H. This budget must ensure an acceptable ratio of costs balanced with therm savings achievements. Since therm savings offset the costs of administrative investment, the greater the achievement, the more cost-effective the programs. If the budget or therm savings upon which the portfolio is built are unrealistic, the Company risks developing a scale-dependent portfolio unable to maintain cost effectiveness.

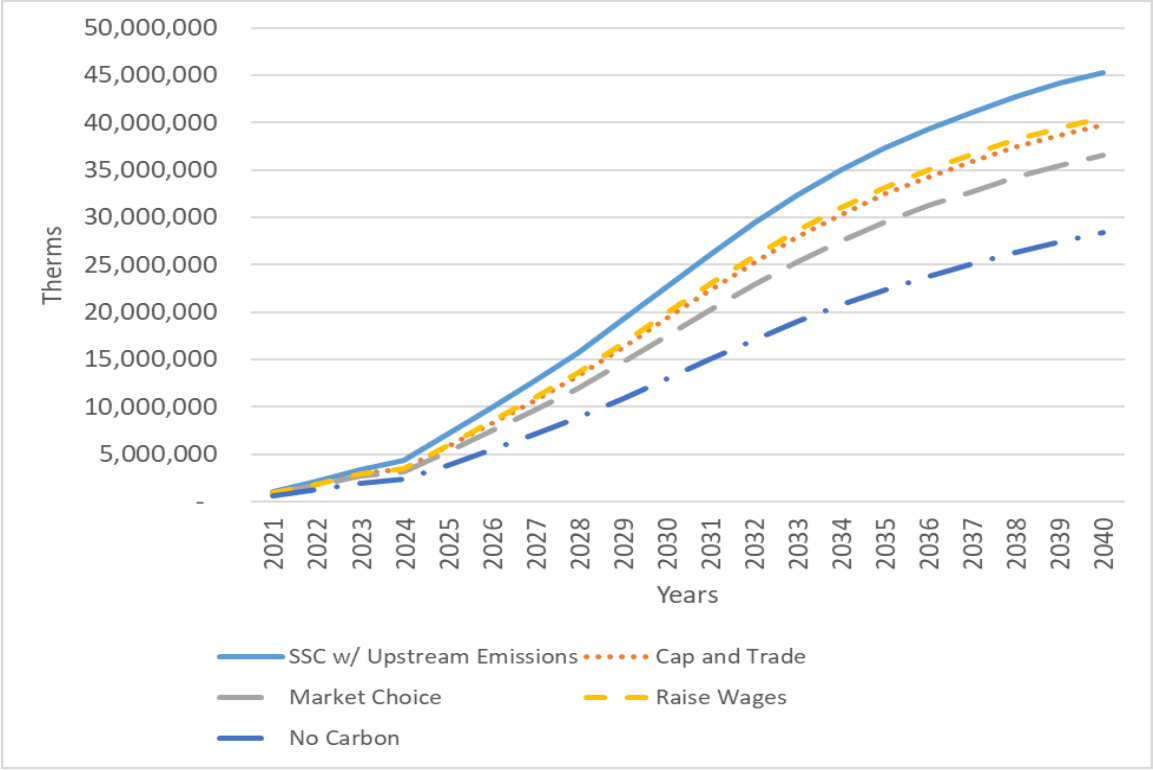
Carbon Scenario Modeling

Cascade modeled alternative carbon scenarios using three sets of potential costs of carbon; Cap and Trade, Market Choice, and Raise Wages. Thus, LoadMAP was re-run under these scenarios. Under all three scenarios, relative to the base, the program identifies an 11% decline in residential and commercial potential energy savings over the cumulative forecasts due to the two and one-half percent social cost of carbon and decreased discount rate from 4.43% to 3.4%; this is seen in the short-term as well. There are minimal differences between scenarios. In the Industrial sector, Cap and Trade and Raise Wages yielded no change while Market Choice reflected a -1.1% change over the cumulative forecast. Details of the results can be found in Appendix D.

In an attempt to show the impact these carbon scenario's have on energy efficiency, Cascade created a no carbon scenario for the other carbon scenario's to compare against.

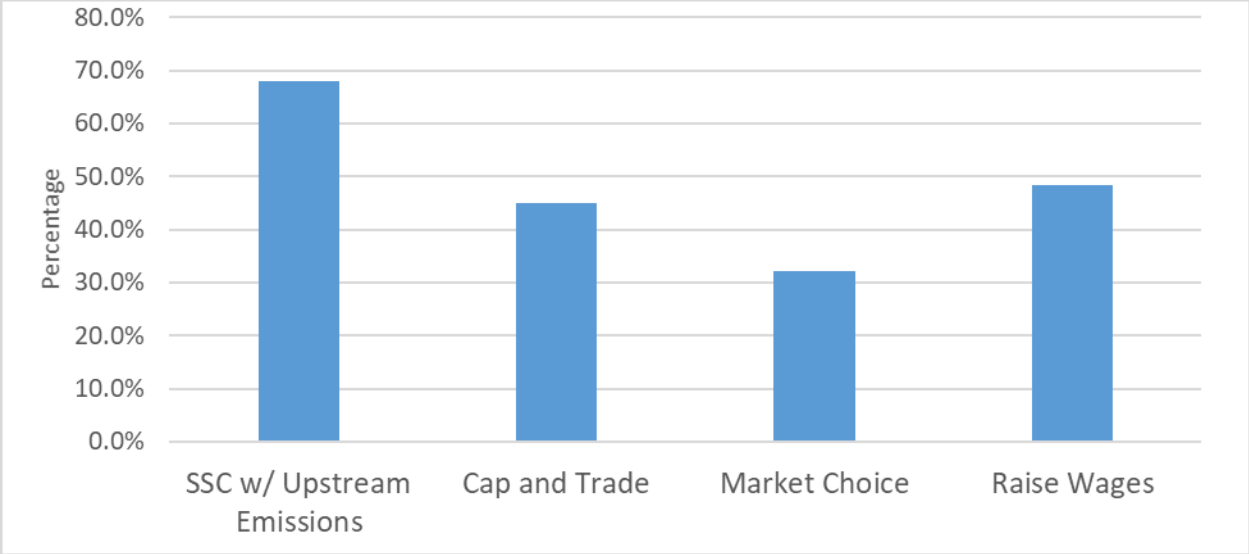
Figure 7-12 shows the cumulative UCT potential forecast across each carbon sensitivity for residential and C/I programs combined, including the no carbon scenario.

Figure 7-12: Cumulative UCT for RES/COM/IND per Carbon Sensitivity



Relative to a no carbon scenario, potential savings from the other carbon scenarios ranged 28.7% to 54.0% higher at the culmination of the 20-year time horizon. Figure 7-13 shows the percent delta, on average, between the cumulative UCT potential forecast across each carbon sensitivity for residential and C/I programs combined relative to a no carbon scenario over the 20 year time horizon.

Figure 7-13: Cumulative UCT for RES/COM/IND per Carbon Sensitivity



Importance of Outreach and Cohesive Messaging

The Company will continue to increase its savings achievements through supporting outreach and community engagement. The EE department regularly reaches out to the Company's customers through the following channels:

- Bill inserts to all qualifying Washington rate schedule customers:
  - These are both hard copy and electronic with topics ranging from Low Income weatherization availability, high-efficiency water heating, whole home weatherization, commercial rebate availability, low cost/no cost savings recommendations, furnaces, combination units, etc.
- Radio campaigns in select territories to promote the incentive program and general low cost/no cost options for reducing natural gas consumption
- Leveraged messaging with community organizations and other utilities
- Community project engagement:
  - When able the Energy Efficiency Department works with local nonprofit groups including Clean Air Agencies to promote more efficient use of natural gas over alternative heating fuels like uncertified wood burning fireplaces
- Home Builder's Association directories, Tours of Homes and Home and Garden Show participation
- The Company has also expanded social media and virtual advertising as a result of being unable to implement standard in person outreach
- When viable, business exposition tabling and exhibition
- Targeted direct mail and email efforts
- Virtual videos and event participation
- Targeted magazine and newspaper advertising

In addition to the standard practices, the Company provides specific details as part of its Conservation Plan where additional efforts above and beyond standard messaging are underway to help increase program participation.

Community Energy Program Partnerships

Cascade partners with local community-based energy programs to support their energy reduction efforts and leverage the opportunity to promote the EEIP to the public. The Company will continue to seek partnerships and support EE efforts throughout its service territory.

In line with Cascade's commitment to community engagement and the desire to increase awareness of its conservation programs, Cascade personnel also partners with the Western Washington University Institute for Energy Studies to provide guest lectures on DSM and energy efficiency, provided a 2020 internship, and supports the Women in Energy Mentoring Network.

Regional Efforts and Long-Term Benefits

Community engagement efforts in tandem with regional endeavors like the NEEA Natural Gas Market Transformation Collaborative have longstanding effects on future therm saving opportunities. The goal is to increase market adoption of energy efficient natural gas products and practices in the future.

The Natural Gas Alliance is well into its second cycle. The Company continues working with this collaborative on the planned activities for cycle 6 (2020-2024). CY 2019 provided the first reportable savings from the market transformation efforts through NEEA. As these savings become more impactful later in the cycle, the Company will work with its CAG on how cost allocations associated with the NEEA efforts will be determined once sufficient savings are accrued and reportable. Company investment in NEEA is shown in Figure 7-14.

Figure 7-14: CNGC NEEA Financial Commitment Schedule

Year	CNGC Washington Commitment at 9.3% for Cycle 5 & 9.2% for Cycle 6
2015	$145,872
2016	$244,996
2017	$313,174
2018	$452,285
2019	$548,804
Cycle 5 Total	**$1,705,130**
2020	$348,908*
2021	$348,908*
2022	$348,908*
2023	$348,908
2024	$348,908
Cycle 6 Total	**$1,744,542**

*Note Cascade pays quarterly - Q4 2020 through Q3 2022 will be at reduced rates due to cycle 5 credit

To further support the Company's engagement in these efforts, Cascade, as well as Northwest Natural Gas are members of the Board of Directors. Cascade's representative is also the current Chair of the NEEA's Natural Gas Board committee and is charged with leading the natural gas discussions on behalf of the Board of Directors and gas funders for the organization.

COVID-19 Response and Future Planning

The current economic model does not take into consideration the impacts of COVID-19 and the subsequent economic downturn. Currently, the C/I program is operating at approximately 70% of therms goal and impacts are likely to carry into 2021. The residential program is forecasted to exceed its therm goal for 2020, but it is unclear if this trend will continue into 2021 given the economic uncertainty of the pandemic. The EE team has employed an adaptive management strategy to respond to the ever-changing economic landscape. Cascade will be working with the CAG on potential alternative scenarios and inputs for LoadMAP to accommodate some of the unknowns and will be addressing issues in real time to remain flexible and responsive to customer needs.

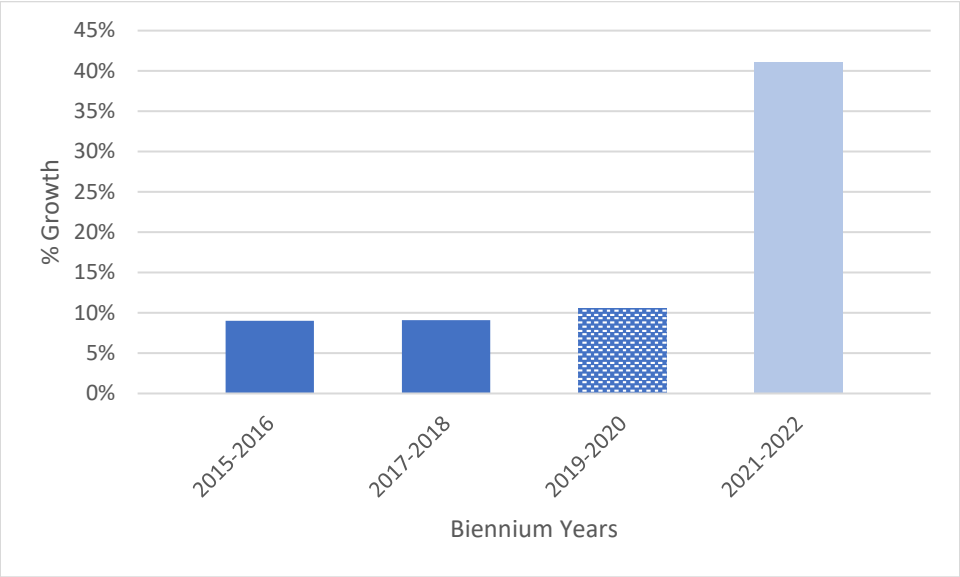
Conclusion and Outlook for Two Year Action Plan

The LoadMAP modelling tool developed by AEG provides a detailed forecast of EE potential. Cascade's EE Department develops strategies to capture this savings potential across its service territory through implementation of programs, outreach, Trade Ally partnerships, and the use of its third-party implementer TRC Companies for C/I program

delivery. Cascade draws on years of experience to adaptively manage its DSM services and will continue to explore all options to actively capture savings to provide value to CNGC's residential, commercial, and industrial customers.

Cascade is projected to exceed its 2018 IRP goal by 3% and is on track to realize an 11% growth over the 2016 IRP. The goal for the 2020 IRP is to grow 41%. Figure 7-15 highlights the portfolio level biennium over biennium growth DSM has seen dating back to the 2014 IRP.

Figure 7-15: Portfolio level Biennium over Biennium Growth



To assist with increasing its capacity to capture energy savings, Cascade has implemented a two-part strategy for the residential program to minimize and reduce information missing from rebate applications. The first part of the strategy was to redesign the application to create a more user-friendly experience and the second step was to work closer with the Trade Ally network to reduce disqualifications. The impetus behind the effort was to reduce the instances of missing information by increasing clarity in document requirements for rebate eligibility. This along with other improvements to processes sets the program up for increasing capacity to manage higher rebate submissions in 2021.

The program has proven itself adaptable to economic shocks to allow continued success toward efficiency targets. This has been achieved through open communication across departments and continued collaboration with company stakeholders. The EE department is taking a variety of steps including implementation of a new customer online interface through Nexant for easier application submittal, to working with AEG to explore adapting LoadMAP to forecast COVID-19 effects on savings potential.

Cascade has developed formulas for its reporting tools that can accurately forecast savings trends on a month-over-month basis. This provides an opportunity for a proactive approach to analyzing how resources are spent to keep savings goals on track throughout the year.

Under this adaptive management philosophy during the COVID-19 pandemic, Cascade increased outreach and marketing through digital platforms increasing awareness across energy efficiency programs. This has been effective for the residential program in 2020, which is expected to exceed goals by 20%. C/I savings have been affected differently by this economic shock, and due to this adverse effect is tracking to achieve under 80% of goal for the year. Cascade is working closely with its C/I vendor to adjust to the needs of the C/I market to seek additional savings opportunities. For example, a mid-stream high efficiency condensing tankless water heater pilot program is now in place. This is intended to further cut incremental costs to customers and drive decisions earlier in the distribution chain to increase the use of commercial energy efficient measures.

Increased cross-departmental collaboration between RPT and EE Team allows for greater understanding of the complete cycle of resource planning and savings potential integration with SENDOUT® allowing for more accurate forecasting and long-term system planning.

Chapter 8

Renewable Natural Gas

Overview

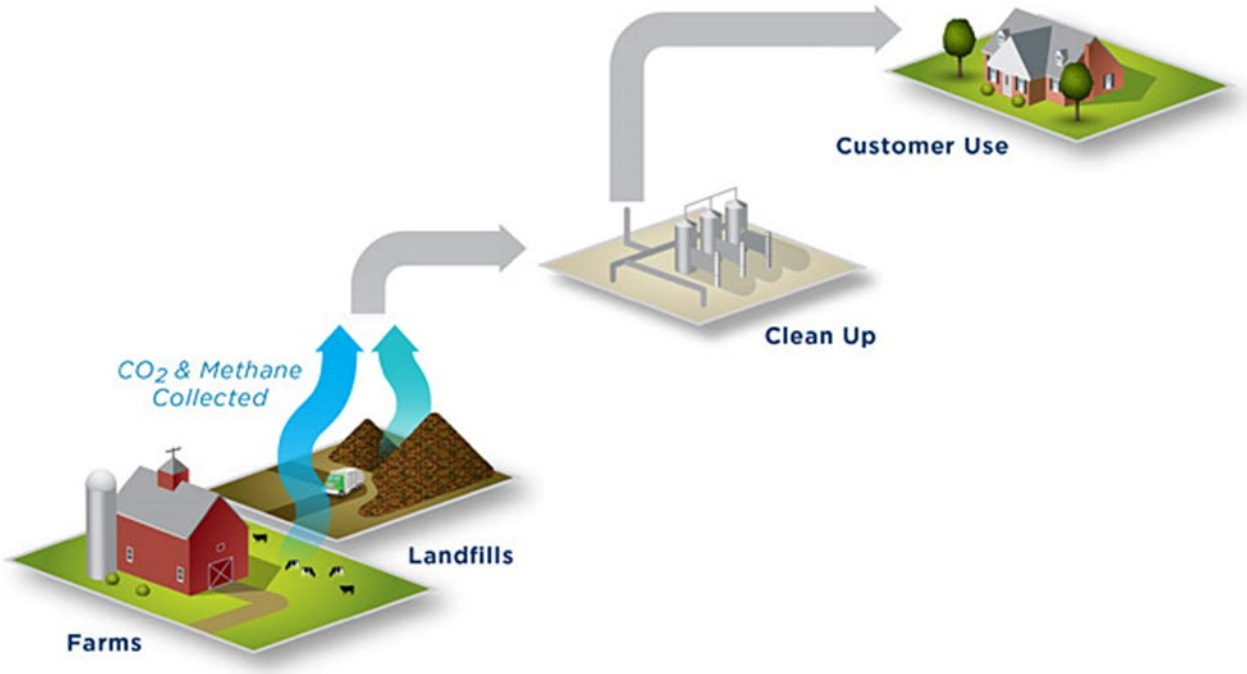
Renewable Natural Gas (RNG), as defined in RCW 54.04.190,[1] is a gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters. Cascade is committed to developing programs that allow the Company to acquire RNG under guidelines and rules stated in Washington HB 1257 and Oregon SB 98.

Figure 8-1,[2] provides an example of a general RNG process from landfill to enduser.

Key Points

- Cascade is committed to developing programs that will allow the Company to acquire RNG under guidelines and rules stated in Washington HB-1257 and Oregon SB 98.
- The Company has met with several individuals, companies, and producers, potentially sponsoring RNG projects such as municipalities, wastewater treatment plants, biodigesters, and landfills.
- On December 4, 2019, the Bend City Council approved its citywide Community Climate Action Plan which includes options for RNG & offsets.
- Taking best practices from other regional LDCs, Cascade has developed a potential RNG cost effectiveness methodology.

Figure 8-1: Example of RNG process from landfill to end user



[1] *See* https://app.leg.wa.gov/rcw/default.aspx?cite=54.04.190
[2] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas

Renewable natural gas, biomethane and biogas are sometimes used interchangeably but they are different biofuel products along the value chain:

- Biogas is a mixture of carbon dioxide and hydrocarbons, primarily methane gas, from the biological decomposition of organic materials.
- Biomethane is a biogas-derived, high BTU gas that is predominately methane after the biogas is upgraded to remove contaminants.
- Renewable natural gas is biomethane upgraded to natural gas pipeline-quality standards so it can substitute or blend with conventional natural gas.[3]

Examples of RNG sources include:

- Biogas from Landfills
  - Collect waste from residential, industrial, and commercial entities.
  - Digestion process takes place in the ground, rather than in a digester.
- Biogas from Livestock Operations
  - Collects animal manure and delivers to anaerobic digester.
- Biogas from Wastewater Treatment
  - Produced during digestion of solids that are removed during the wastewater treatment process.
- Other sources include organic waste from food manufacturers and wholesalers, supermarkets, restaurants, hospitals, and more.[4]

Biofuel estimates vary, for example, E3 estimates 25 million dry tons of biomass supply available to Washington and Oregon, compared to Washington State's deep decarbonization study which assumed 23.8 million dry tons available to the state.[5]

Carbon Intensity

A major driving force behind investment in RNG is the potential to mitigate the carbon footprint associated with traditionally sourced natural gas. For some types of projects such as compressed natural gas (CNG) from landfills, the resulting RNG still emits carbon into the environment, but at a lower intensity. For other projects, such as gas sourced from solid waste and dairy cow manure, high carbon intensity gas that would have otherwise been vented into the atmosphere is captured through the production of RNG. In these cases, no new carbon is placed into the environment as a result of the biogas consumption, and less carbon enters the atmosphere than would have

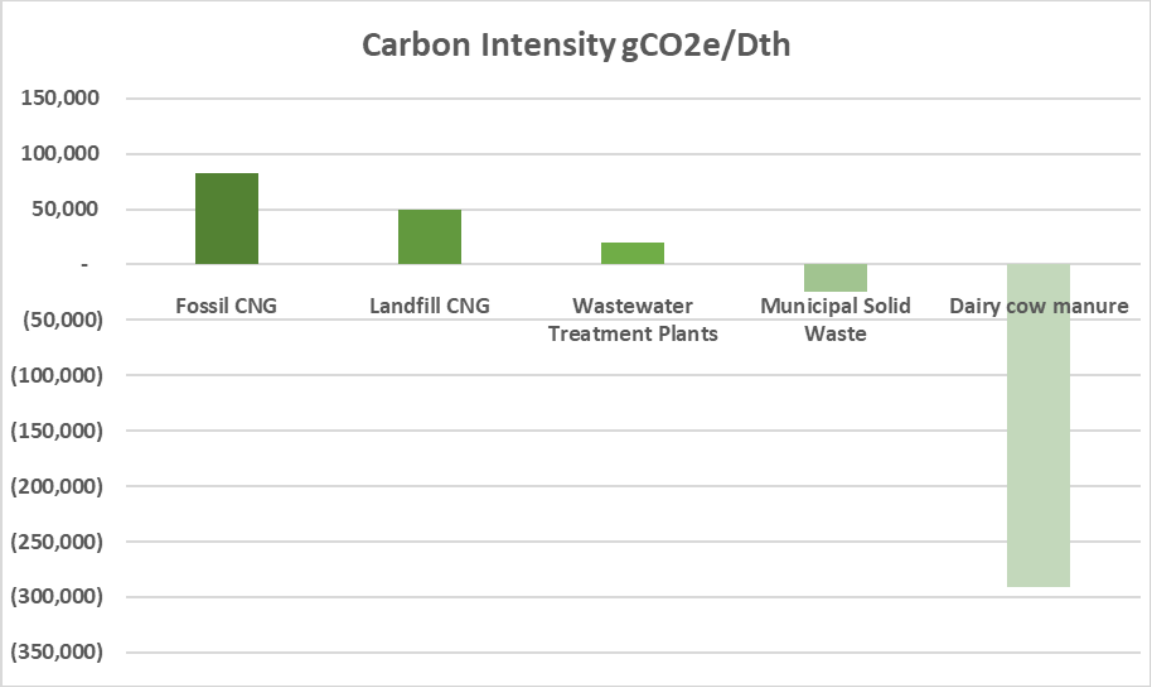
[3] American Natural Gas.com

[4] U.S. Department of Energy, Alternative Fuels Data Center, Renewable Natural Gas

[5] Energy + Environmental Economics, Pacific NW Pathways to 2050: Achieving an 80% reduction in economy-wide greenhouse gases by 2050

otherwise occurred without the project. Figure 8-2 highlights the various impacts of five different types of natural gas.[6]

Figure 8-2: Carbon Intensity of Natural Gas by Source



Regulatory discussions in both Washington and Oregon have focused on how differences in carbon intensity should be addressed when assessing the carbon neutralizing benefits of renewable natural gas. Some parties believe it is best to treat all RNG the same to encourage investment in any projects available to produce RNG. Others argue it is critical to capture the exact impact of each RNG project. Cascade will closely monitor the emerging laws and regulations in both states to ensure the Company properly evaluates all future RNG projects.

[6] *See* https://ww2.arb.ca.gov/sites/default/files/classic//research/apr/past/13-307.pdf

RNG Regulation and Policy in Washington

On April 15, 2019 House Bill 1257[7] (HB 1257) was passed by the Senate and on April 18, 2019 the bill was passed by the House. Several sections within the bill are related to RNG and will be covered in this chapter.

Below, Cascade lists key portions of the House Bill relevant to RNG:

Sec. 12. (1) The legislature finds and declares that:

(a) Renewable natural gas provides benefits to natural gas utility customers and to the public; and

(b) The development of renewable natural gas resources should be encouraged to support a smooth transition to a low carbon energy economy in Washington.

(2) It is the policy of the state to provide clear and reliable guidelines for gas companies that opt to supply renewable natural gas resources to serve their customers and that ensure robust ratepayer protections.

Following the adoption of HB 1257 into law,[8] workshops were convened to determine how best to comply with these new mandates. Cascade has actively participated in all relevant workshops under UG-190818, RNG Staff Investigation. Multiple company representatives engaged in these proceedings. The Company has also worked closely with its trade organization, the Northwest Gas Association, to provide the information and feedback necessary to support proposals submitted on behalf of the northwest LDCs.

In addition to Section 12, HB 1257 included two other sections with language pertaining to the development of renewable natural gas and offset programs:

Sec. 13. A new section is added to chapter 80.28 RCW to read as follows:

(1) A natural gas company may propose a renewable natural gas program under which the company would supply renewable natural gas for a portion of the natural gas sold or delivered to its retail customers. The renewable natural gas program is subject to review and approval by the commission. The customer charge for a renewable natural gas program may not exceed five percent of the amount charged to retail customers for natural gas.

(2) The environmental attributes of renewable natural gas provided under this section must be retired using procedures established by the commission and may not be used for any other purpose. The commission must approve procedures for banking and transfer of environmental attributes.

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[7] *See* http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20201020144814

[8] Signed by Govermnor Jay Inslee on May 13, 2019 with an effective date of July 28, 2019.

(3) As used in this section, "renewable natural gas" includes renewable natural gas as defined in RCW 54.04.190. The commission may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels.

Cascade looks forward to identifying viable pathways for the inclusion of renewable natural gas as part of its fuel mix, following the guidelines developing from the UG-190818, RNG Staff Investigation workshops. To date, Cascade has been in discussions with several RNG producers and is also considering a more comprehensive analysis of available RNG resources across its Washington and Oregon service areas. In the spring of 2019, CNGC initiated exploratory discussions regarding the City of Bellingham's new Post Point waste plant and with WWU's Campus Energy Manager to identify potential opportunities for RNG and to emphasize CNGC's interest in partnering on RNG projects. Such an analysis would be accompanied by a Request for Information (RFI) to identify viable biogas sources and determine the appropriate volume of RNG to include on Cascade's system. The Company may also solicit recommendations from a third party consultant for program design and structure.

The Company does not currently have a timeline to implement incorporating RNG onto the system. However, Cascade has developed a cost effectiveness evaluation tool for RNG to allow the Company to model the impact to retail customers in order to not exceed the five percent of the amount charged from section 13.1 of the bill.

Sec. 14. A new section is added to chapter 80.28 RCW to read as follows:

(1) Each gas company must offer by tariff a voluntary renewable natural gas service available to all customers to replace any portion of the natural gas that would otherwise be provided by the gas company. The tariff may provide reasonable limits on participation based on the availability of renewable natural gas and may use environmental attributes of renewable natural gas combined with natural gas. The voluntary renewable natural gas service must include delivery to, or the retirement on behalf of, the customer of all environmental attributes associated with the renewable natural gas.

(2) For the purposes of this section, "renewable natural gas" includes renewable natural gas as defined in RCW 54.04.190. The commission may approve inclusion of other sources of gas if those sources are produced without consumption of fossil fuels.

As noted above, Cascade is currently assessing options for how to best acquire RNG and its associated attributes. These resources would be applied for the purposes described under Sec 13 and 14 of HB 1257. Cascade is in the process of identifying internal and external resources to support the acquisition of environmental attributes and renewable gas to support the voluntary renewable natural gas service required under law. This process will likely include an assessment of customer interest in such a program, so that attributes can be acquired in a prudent and cost-effective manner.

RNG Regulation and Policy in Oregon

For informational purposes only, the following describes related RNG activity in Oregon. On January 14, 2019, SB 98 was introduced in Oregon legislation. SB 98 requires the Oregon Public Utility Commission (OPUC) to adopt by rule a renewable natural gas program for natural gas utilities. The program allows utilities to recover prudently incurred qualified investments in meeting certain targets for including renewable natural gas in gas purchases for distribution to retail natural gas customers. On June 23, 2019, SB 98 was signed into law effective September 29, 2019.

On August 27, 2019, the OPUC initiated docket UM 2030, an investigation into the use of Northwest Natural's RNG evaluation methodology. Cascade is an active participant in UM 2030. The Company has developed its own potential Cost Effectiveness Evaluation Methodology which is described in the next section.

On October 1, 2019, the OPUC Staff initiated docket AR 632, in the matter of rulemaking regarding the 2019 SB 98 RNG programs. Cascade has participated in multiple meetings regarding this docket. On February 20, 2020, the OPUC provided informal draft rules for the docket. On July 16, 2020, OPUC Order 20-227 adopted the rules from AR 632.

Below is a brief description of the preliminary rule followed by the Company's compliance with its relevant sections:

(1) According to preliminary rule 860-150-100 of AR 632, each large natural gas utility and small natural gas utility must, as part of an integrated resource plan (IRP) filed after August 1, 2020, include information relevant to the RNG market, prices, technology, and availability that would otherwise be required under the Commission's IRP guidelines, by order of the Commission, or by administrative rules.

Cascade has provided information relative to the RNG market, prices, technology, and availability under the Cascade Market Research subsection later on in the chapter.

(3) In addition to the information required under section (1), each small natural gas utility must also include in its IRP:

> (a) An indication whether and when the utility expects to make a filing with the Commission, pursuant to OAR 860-150-0400, of its intent to begin participating in the RNG program described in these rules, if the utility has not already started to participate in the RNG program;

Cascade has been in discussions with several RNG producers. The Company may also seek the support of a third party consultant or consultants to help identify its full

biogas potential in both WA and OR, and to support offset and attribute acquisition as appropriate. Currently, there is no immediate timeline for putting RNG on the system. The Company will update stakeholders, though, as events warrant.

> (b) Information about opportunities, challenges, perceived barriers, and the natural gas utility's strategy for participation in the RNG program described in these rules; and

Cascade has listed information about opportunities, challenges, and perceived barriers in the Cascade Market Research section. Cascade's current strategy is to gather all market intelligence regarding RNG. This includes meeting with RNG producers and other regional LDCs, looking into third party consultant support, and monitoring RNG legislation. Gathering as much information as possible will give Cascade the opportunity to make prudent decisions when the Company begins participation in RNG programs.

> (c) The cost effectiveness calculation that the utility will use, pursuant to OAR 860-150-0200, to evaluate RNG resources, if the utility has not already filed this with the Commission pursuant to OAR 860-150-0400.

Cascade's cost effectiveness calculation is described in the following section.

Cascade Project Cost Effectiveness Evaluation Methodology

Several departments within the Company have collaborated to create a model that allows Cascade to evaluate the cost-effectiveness of all potential RNG projects before entering into an agreement with potential suppliers. Similar to the Company's SENDOUT® modeling, the results of this calculation help inform final acquisition decisions, but ultimately must be combined with qualitative analysis from RNG subject matter experts. This subsection will present the model notes, a discussion of the static and dynamic inputs to the model, and provide an understanding of how the results should be interpreted.

Cost Effectiveness Evaluation Model Notes

$$C_{RNG} = I_{RNG} - AC_U - AC_D + \sum_{T=1}^{365} (P_{RNG} + VC - CIF) * Q$$

$$C_{Conventional} = \sum_{T=1}^{365} (P_{Conventional} + VC) * Q$$

Where:

C_{RNG} = The all-inclusive annual cost of a proposed RNG project
I_{RNG} = The annual required investment to procure a proposed RNG resource. If Cascade is simply buying the gas and/or environmental attributes, this value is zero.
AC_U = Avoided upstream costs
AC_D = Avoided distribution system costs
P_{RNG} = Daily price of renewable natural gas being evaluated
Q = Daily quantity of gas being evaluated
VC = Variable cost to move one dekatherm of gas to Cascade's distribution system. This value can be zero if a project connects directly to the Company's system.
CIF = Carbon Intensity Factor. This is calculated by multiplying the Company's expected carbon compliance cost by 1 minus the ratio of a proposed project's carbon intensity to conventional gas' carbon intensity.
$C_{Conventional}$ = The all-inclusive annual cost of conventional natural gas.
If $C_{Conventional} \geq C_{RNG}$, a project can be considered cost effective, and should be acquired. If not, the project may still be considered under the regulatory exceptions discussed earlier in this chapter.

Static Versus Dynamic Inputs

Inputs to Cascade's model can be classified as either static or dynamic. Static inputs are ones that are not project specific, but rather related to the Company's system as a whole. They include Cascade's avoided costs, costs associated with the price of conventional gas, and regulatory factors that are used to calculate the impact to revenue requirement. Dynamic inputs on the other hand, are ones that need to be updated on a project by project basis. These include the price and quantity of the RNG, initial investment required, and carbon intensity of the project.

Model Results

Once all inputs are populated, the model provides three main pieces of information: The potential enterprise value of the project over its lifetime, the first year dollar impact to revenue requirement, and the first year percentage impact to revenue requirement. As discussed in the model notes, if the cost of conventional gas is greater than or equal to the cost of RNG, the project can be considered cost effective. If not, the impact to revenue requirement provides a valuable insight as to whether the project is attractive from a regulatory perspective.

RNG Scenarios

For the 2020 IRP, Cascade is introducing two new scenarios related to RNG modeling. Both scenarios are hypothetical and do not reflect current negotiations with actual RNG producers, but rather allow the Company to model the financial impacts of adding either off-system or on-system RNG to its portfolio. An on-system project is a project that connects directly to Cascade's distribution system. An off-system project requires upstream pipeline capacity to deliver the RNG to Cascade's distribution system. Additionally, it is important to reiterate while the information from these scenarios is valuable, SENDOUT® modeling is only one tool that will be used in the RNG evaluation process. Qualitative review of these results, along with other elements that cannot be captured in SENDOUT® but are discussed in Cascade's Project Cost Effectiveness Evaluation Methodology, will be key to the final decisions regarding the acquisition of RNG.

Figure 8-3 compares the annual costs of the Company's portfolio to the costs when an on-system RNG project is added, while Figure 8-4 shows the impact of an off-system RNG project. For both scenarios, Cascade modeled 300 dth/day of must take supply at $13.50/dth before environmental attributes. Also, the carbon intensity savings modeled was a simple average of the intensities of each different type of RNG that Cascade considers.

Figure 8-3: RNG Cost Comparison – On-System RNG

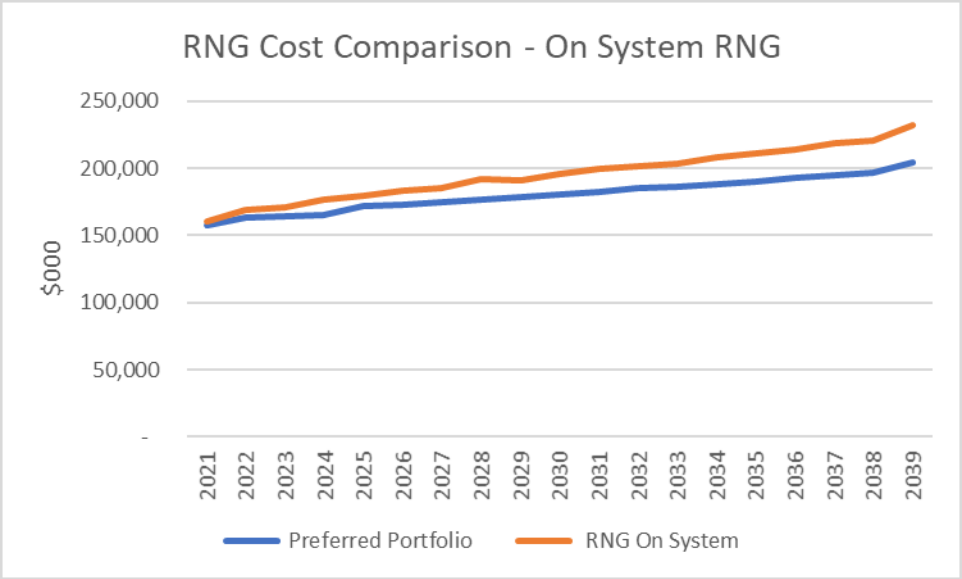
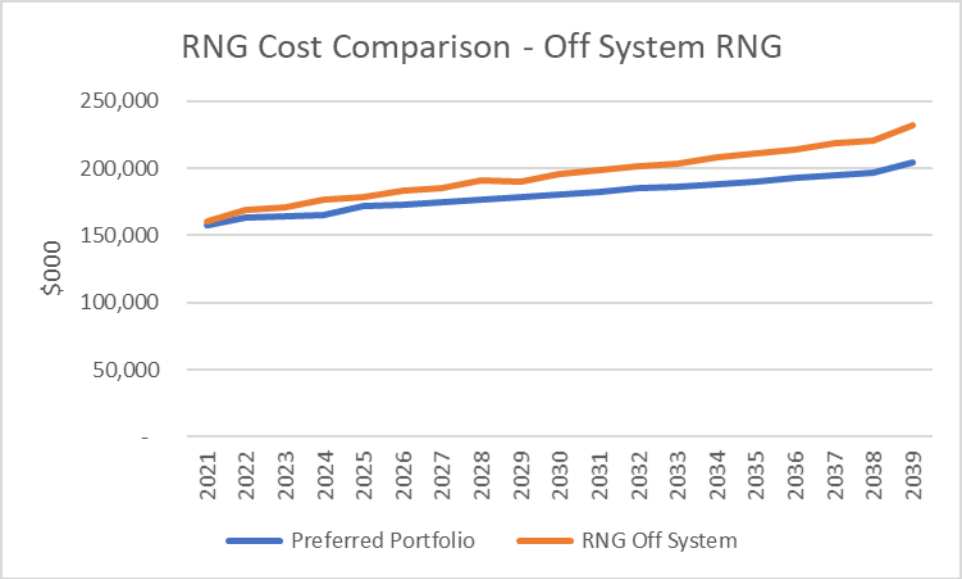


Figure 8-4: RNG Cost Comparison – Off-System RNG



Cascade Market Research

The Company has met with several individuals and companies within the RNG industry such as producers, municipalities, wastewater treatment plants, biodigesters, and landfills. During these conversations, Cascade has gathered market intelligence around RNG. Some of the Company's findings include:

- Options for securing RNG will involve purchase and/or participation in infrastructure.
- No "spot market" for RNG at this point due to long off-take commitments.
- Lead times on new RNG projects up to 36 months.
- Landfill projects are typically the largest RNG opportunity at 300-600 dth/day and usually require the lowest capital investment.
- Digester projects, due to higher carbon intensity, do very well in the Renewable Identification Numbers (RINs) market and run 50-500 dth/day (expensive to operate).
- Food waste/wastewater treatment projects seen as an ideal option for utilities as they have low RINs and Low Carbon Fuel Standards (LCFS) potential.
- $13-$30/dth long-term off-take deals.

Cascade will continue to refine its understanding of available RNG resources, market characteristics, and overall potential for RNG use and intergration by the Company on behalf of its customers.

City of Bend Climate Action Plan

On December 4, 2019, the Bend, Oregon City Council (the City) approved its citywide Community Climate Action Plan. The plan, which was developed with the guidance of the Climate Action Steering Committee (CASC), is designed to guide the City and the community in pursuit of reducing fossil fuel use by 40% by 2030 and by 70% by 2050.

The Climate Action Plan is comprised of voluntary efforts to encourage greater energy efficiency, use of renewable energy, and resource management in the Bend community. Cascade served as an active participant on Bend's CASC, and continues to support the City's carbon reduction planning efforts.

Cascade and the City share a mutual desire to identify areas of partnership on RNG development. Cascade is currently in discussion with Bend on the exploration of renewable natural gas through the City's wastewater treatment plant, or similar facilities. The Company is also considering the development of a voluntary program to offset fossil gas usage.

Cascade will continue to work with Bend in exploration of RNG and other low carbon opportunities in support of its climate ambitions. The Company will also keep apprised of other communities interested in placing RNG in the distribution system and will coordinate as appropriate.

RNG Projects

As mentioned earlier, the Company has met with several individuals and companies within the RNG industry such as producers, municipalities, wastewater treatment plants, biodigesters, and landfills. Location, type of project, and other details are discussed throughout this process to evaluate specific resources. Due to the sensitivite nature regarding the detailed information of actual RNG projects, Cascade provides details in Appendix J under confidential treatment.

RNG Goals

An internal committee composed of Business Development, Gas Supply, Operations, Resource Planning, Engineering, Energy Efficiency, and Regulatory personnel has been working with senior management with the goal of developing Cascade's long-term strategy for RNG. As part of these discussions the Company is considering creating a dedicated staff position for RNG policy, practice, and direction within the corporate structure. This RNG specific function would likely have overall responsibility for coordinating among various corporate departments and activities (including those related to the IRP) that are effected by RNG activities. Cascade is also considering the services of a third party consultant with expertise in biogas procurement to assess the full breadth of resources available across Cascade's Washington and Oregon service areas, and to help develop a viable long-term strategy for RNG. Additional support may also be considered for the assessment and development of the Washington mandated offset program described earlier in this chapter.

Additionally, the Company has a goal of continued participation in various RNG rulemakings across the region. Cascade is actively engaged with other LDCs and industry groups to respond to RNG-related legislation in Washington and Oregon (e.g. Washington HB 1257 and Oregon SB 98, respectively). Cascade is working towards ensuring compliance with RNG rules and regulations identified in dockets such as WUTC docket U-190818 and OPUC dockets AR 632, UM 2030.

Cascade recognizes RNG related rules include the development of possible programs to make RNG directly available to requesting customers. The Company will work to develop programs that allow Cascade to acquire RNG, while ensuring that related costs to rate base don't result in rate increases of over 5% of the Company's authorized revenue requirement. These resources may ultimately be required to comply with rules and create required programs.

Please see Chapter 12, Two-Year Action Plan, for more information about future RNG action items.

Conclusion

RNG presents Cascade with an exciting opportunity to introduce a new resource into the Company's IRP. Cascade echoes the sentiment of Washington and Oregon regulatory bodies and the general public to provide for RNG in its system. The Company is actively participating in the process of crafting emerging requirements in state law and regulatory principles.

Because of the uncertainty surrounding what will ultimately be the value of environmental attributes, Cascade cannot at this time definitively conclude what types of RNG programs will prove to be cost effective during the 2020 IRP planning horizon. The Company will update its models and analysis in future IRPs as more information becomes available.

Chapter 9

Distribution System Planning

Overview

Cascade's IRP includes the evaluation of safe, economical, and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to Cascade's citygates are necessary elements for providing gas to the customer; the other essential element is ensuring the distribution system growth behind the citygates is not constrained. Important parts of the planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions, and estimating costs for distribution system enhancements.

Key Points

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

Analyzing resource needs in the IRP ensures adequate upstream capacity is available to the citygates, especially during a peak event. Distribution planning focuses on determining if adequate pressure will be available during a peak hour. Given this nuance, distribution planning supplements the goals, objectives, risks, and solutions as resource planning.

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

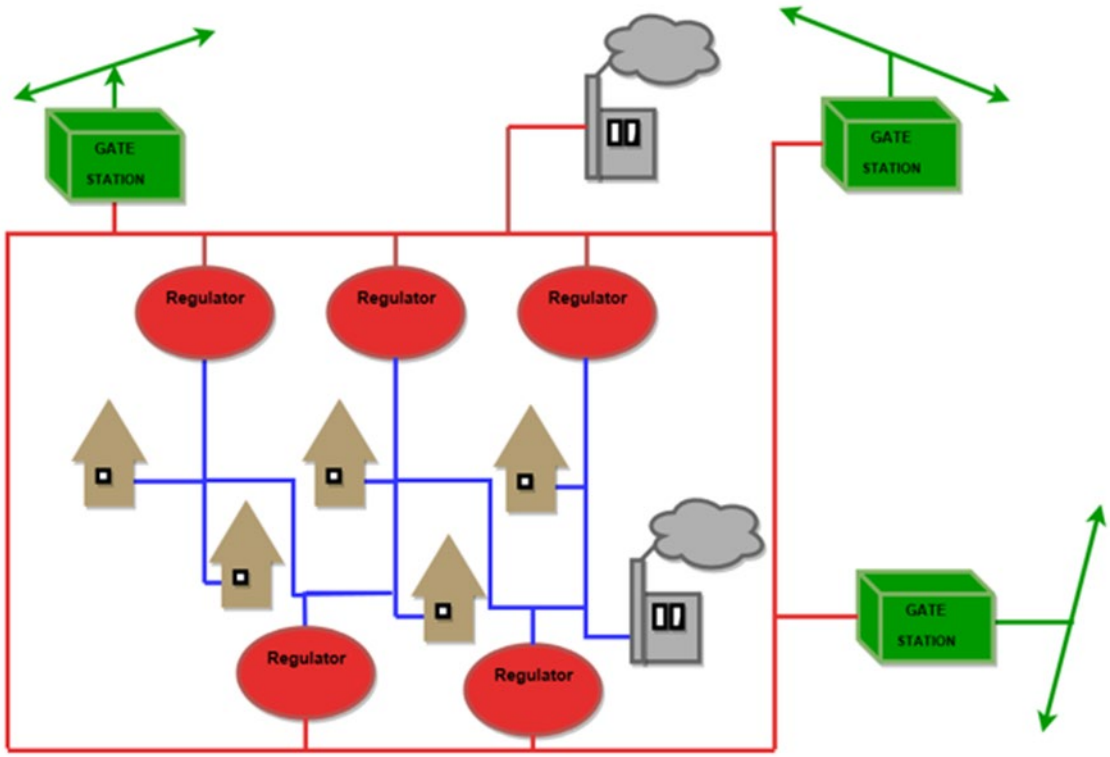
Network Design Fundamentals

Gas distribution networks rely on pressure differentials to move gas from one location to another. If the pressure is exactly the same on both ends of a pipe, the gas will not flow. Therefore, it is important that gas engineers design the distribution network such that the pressure in the pipe will always be high enough that a differential can be created when gas leaves the system. As gas flow increases, pressure is lost due to friction. Using the laws of fluid mechanics,

engineers, informed by flow modeling data, determine the maximum flow of gas through a pipe of a certain diameter and length that will not cause pressure drops that are too great.

Not all natural gas flows equally throughout a network. Certain points within the network constrain flow and restrict overall network capacity. Network constraints can occur as demand requirements evolve. Anticipating these demand requirements, identifying potential constraints, and forming cost-effective solutions with sufficient lead time without overbuilding infrastructure, are the key challenges in network design. Figure 9-1 provides an example of a network diagram.

Figure 9-1: Network Design Fundamentals



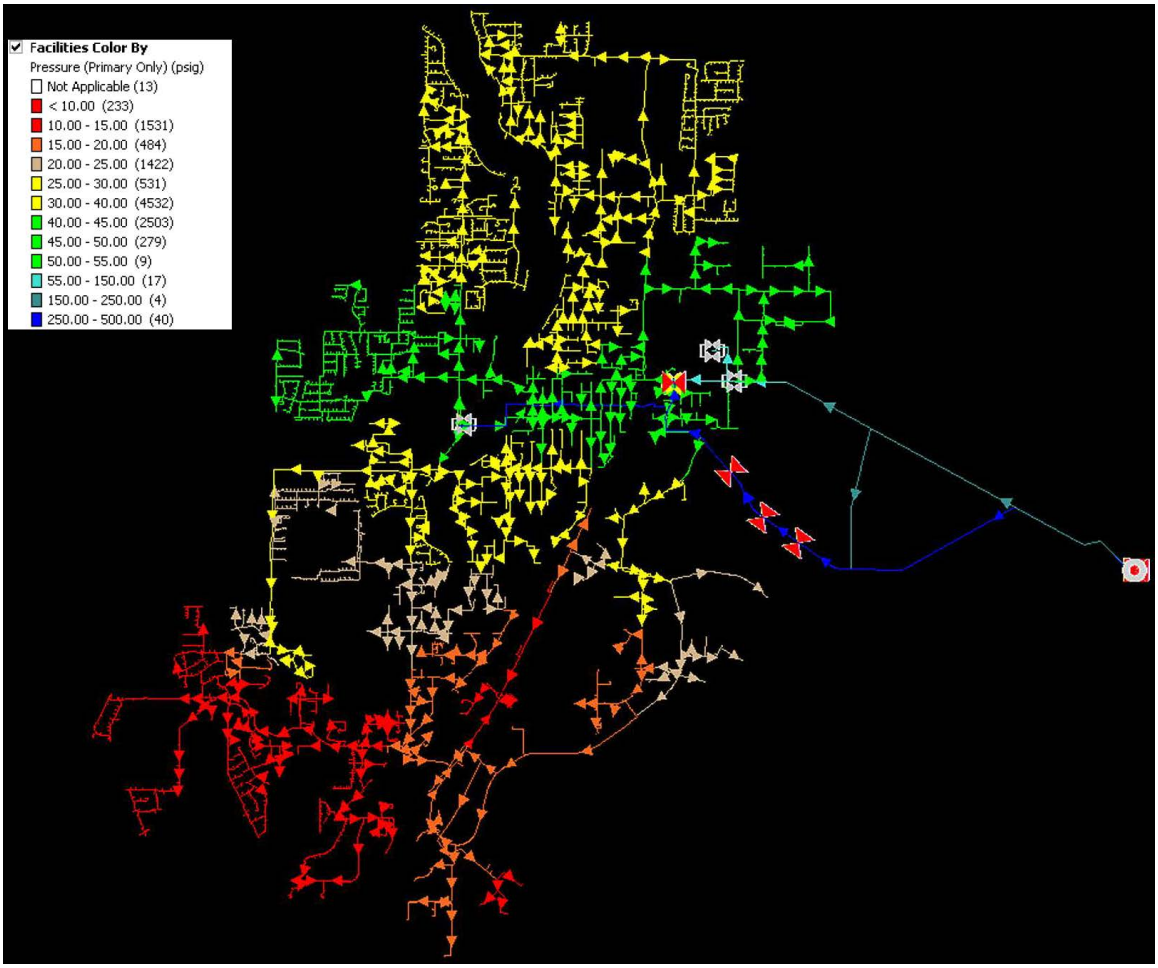
Computer Modeling

Developing and maintaining effective network design is aided by computer modeling for network demand studies. Demand studies have evolved with technology in the past decade to become a highly technical and powerful means of analyzing distribution system performance. Utilizing computer software, individual models are 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 demand forecasts, the pressures within each system are checked. When the simulation shows the pressure

dropping to an unacceptable level, that system and the surrounding area are determined to be a constraint area. When constraint areas are found, an engineer determines the most cost-effective way of solving the problem.

Cascade's geographical information system (GIS) keeps an up-to-date record of pipe and facilities, complete with all system attributes such as date of installation and operating pressure. Using the internal GIS environment and other input data, Cascade creates system models through the use of Synergi® software. The software provides the means to model piping and facilities to represent current pressure and flow conditions while predicting future events and growth. Combining these models with historical weather data provides a design day model that can predict a worst-case scenario. Design day models predicting a constraint area are identified and remedied before a real problem is encountered. Figure 9-2 is an example of a low-pressure scenario (constraint area) identified using Synergi®. Ultimately the planned projects can be funneled through the Distribution System Planning Process Flow (Figure 9-4 on Page 9-10) to be prioritized and slotted into the budget.

Figure 9-2: Constraint Area Example



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

Distribution System Planning

Many LDCs conduct two primary types of evaluations in their distribution system planning efforts to determine the need for resource additions such as distribution system reinforcements and expansions. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability, and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution enhancements.

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

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

Distribution System Enhancements

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification, and corresponding optimum combinations of pipe modification, and pressure modification solutions to maintain adequate pressures throughout the network. Distribution system enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The purpose of this is to get in front of potential constraints on the distribution system. Distribution system enhancements do not reduce demand, nor

do they create additional supply. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Pipelines

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

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

Pipeline uprating increases the maximum allowable operating pressure of an existing pipeline. This enhancement can be a quick and relatively inexpensive method of increasing capacity in the existing distribution system before constructing more costly additional facilities. However, safety considerations and pipe regulations may prohibit the feasibility or lengthen the time before completion of this option. Also, increasing line pressure may produce leaks and other pipeline damage creating costly repairs. A thorough review is conducted to ensure pipeline integrity before pressure is increased. Figure 9-3 provides a snapshot of some of the major components of Cascade's pipeline system.

Figure 9-3: Cascade System Pipeline Overview

PIPELINE:

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

Regulators

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

Compression

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

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

Compressors can be a cost-effective option to resolving system constraints; however, regulatory and environmental approvals to install a station, along with

engineering and construction time, can be a significant deterrent. Adding compressor stations typically involves considerable capital expenditure. Based on Cascade's detailed knowledge of the distribution system, there are no foreseeable plans to add compressors to the distribution network.

Conservation Resources

Reviewing the impacts of proposed conservation resources on anticipated distribution constraints is equally important. Although Cascade historically provides utility-sponsored energy efficiency programs throughout a particular jurisdiction (i.e. all of Cascade's Washington or Oregon service territory), there may be instances where a more targeted approach could reduce or delay the estimated reinforcement for a specific area. As discussed in Chapter 7, Demand Side Management, the acquisition of conservation resources is entirely dependent upon the individual consumer's day-to-day purchasing and behavior decisions. While Cascade attempts to influence these decisions through its energy efficiency programs, the consumer is still the ultimate decision maker regarding the purchase of an energy efficiency measure. Therefore, Cascade does not anticipate that the peak day load reductions resulting from incremental energy efficiency measures will be adequate to eliminate distribution system constraint areas at this time. However, over the longer term (through 2027), the opportunity for targeted energy efficiency programs to provide a cumulative benefit that offsets potential constraint areas may be an effective strategy.

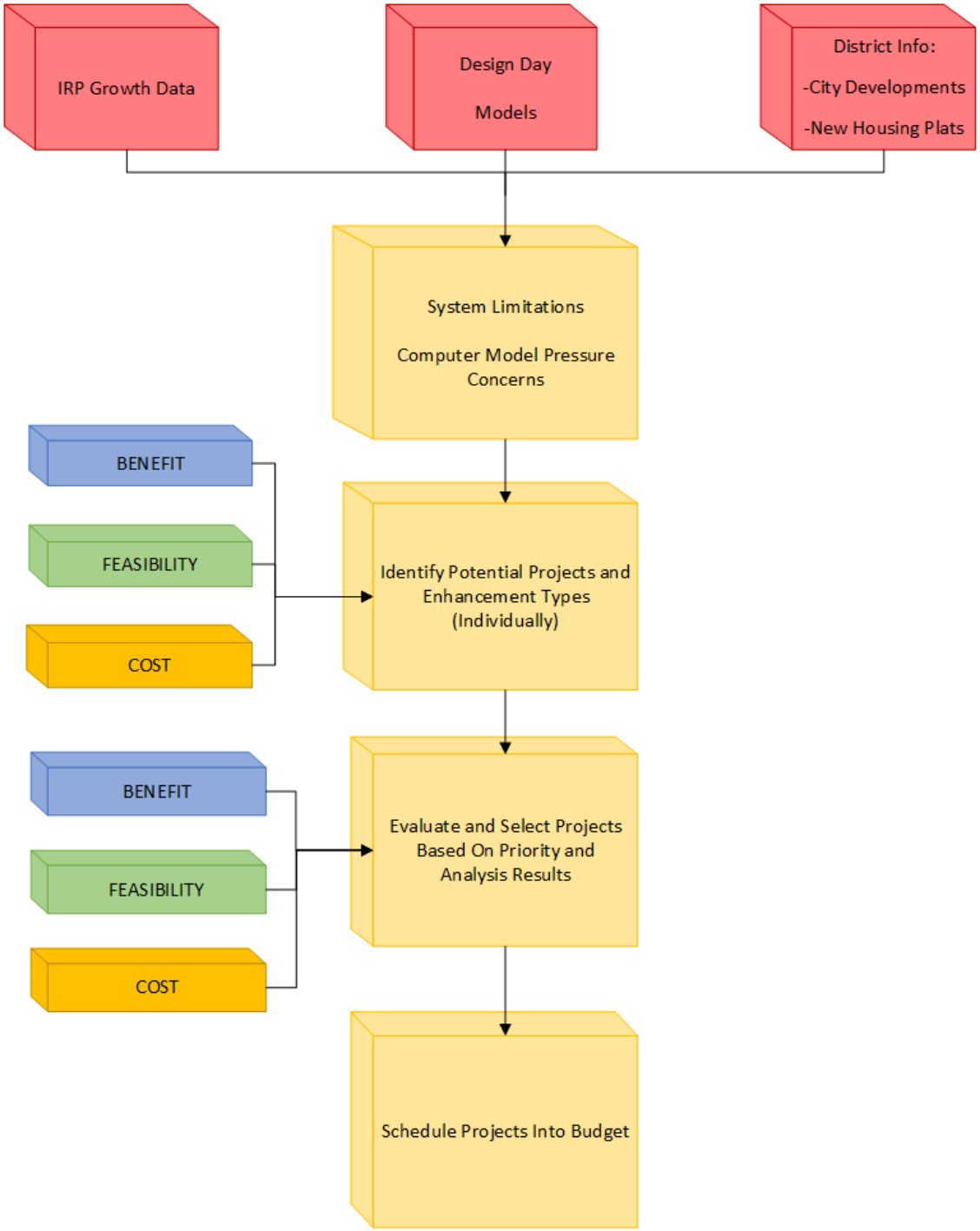
Distribution System Planning Process Flow

After developing a working demand study, analyses are performed on every system at design day conditions to identify areas where potential outages may occur. These constraint areas are then prioritized against each other to ensure the areas with the greatest constraints are corrected first and that others are properly addressed. Within a given area, projects/reinforcements are selected using the following criteria:

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

Once a project/reinforcement is identified, the design engineer, field operations coordinator, or energy services representative begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of the above project/reinforcement selection criteria. Figure 9-4 provides a schematic representation of the distribution system planning process flow.

Figure 9-4: Distribution System Planning Process Flow



Distribution System Planning Results

Figure 9-5 summarizes the estimated costs and timing of distribution system enhancements in Cascade's nine Washington districts. The summary of these enhancements provides preliminary estimates of timing and costs of major reinforcement solutions addressing growth-related system constraints. The scope and needs of distribution system enhancement projects generally evolve with new information requiring ongoing reassessment. Actual solutions may differ due to changes in growth patterns and/or construction conditions that diverge from the initial assessment.

Figure 9-5 provides a summary of Cascade's upcoming growth projects. The specific engineering projects can be found in Appendix I. With the use of the computer modeling software and Cascade's Distribution System Planning Process Flow, Cascade can identify projects for the longer term. As projects are completed they are integrated into the system to ensure the model is current.

Figure 9-5: Distribution Planning Project Summary

Location	2021	2022	2023	2024
Aberdeen District	$2,551,000.00	$-	$891,000.00	$4,698,000.00
Bellingham District	$1,574,000.00	$1,245,000.00	$-	$-
Bremerton District	$-	$-	$-	$-
Kennewick District	$3,963,000.00	$5,682,000.00	$-	$-
Longview District	$1,318,000.00	$-	$-	$-
Mount Vernon District	$779,000.00	$-	$-	$-
Walla Walla District	$1,308,000.00	$-	$-	$-
Wenatchee District	$-	$-	$-	$-
Yakima District	$3,013,000.00	$-	$-	$-

Conclusion

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

Chapter 10

Resource Integration

Overview

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

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

Key Points

- Cascade utilizes SENDOUT® to find the optimal solve for forecasted resource deficiencies, as well as alternative portfolios.
- Once a solution is found under expected conditions, the candidate portfolio is stress-tested through stochastic and deterministic scenarios using Value at Risk (VaR) analysis.
- The Top-Ranked Candidate portfolio includes all existing resources, consideration of incremental NGTL transportation and Spire Storage, plus incremental DSM.
- Cascade does not forecast any shortfalls over the 20-year planning horizon, but this does not supplant the need for incremental resources such as storage to improve supply reliability and operational balancing needs.
- For the 2020 IRP, Cascade evaluates seventeen traditional scenarios and seven sensitivities, plus four extreme scenarios.
- The Preferred Portfolio is Cascade's least cost, least risk solution to how to serve its customers over the planning horizon.

Supply Resource Optimization Process

The process for optimizing supply resources is summarized in the following eight steps and is shown graphically in Figure 10-2 on page 10-5.

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

- **Step 2: Introduce Additional Resources**
  - Once shortfalls were identified, Cascade utilized SENDOUT® to derive a diverse selection of potential portfolios to eliminate the deficiency. This was done through a deterministic analysis of the alternative resources. For the 2020 IRP, Cascade tested seven potential portfolios. Figure 10-1 groups these portfolios by the source of each resource. Further details

regarding the components of each candidate portfolio can be found in Appendix G.

Figure 10-1: Breakdown of Candidate Portfolios

	GTN	No GTN
NWP	- All-In - All-In Less DSM	- NWP Only - NWP Only w/ Storage
No NWP	- GTN Only - GTN Only w/ Storage	- Storage Only

- **Step 3: Stochastic Analysis of All Portfolios Under Existing Conditions**
  - Once Cascade selected its portfolios, each one was tested stochastically. Each portfolio was run through a 10,000 draw Monte Carlo weather simulation under normal growth, pricing, and storage/supply accessibility. The Company recorded the total system cost and unserved demand of each draw, as these are the metrics used to rank the portfolios.

- **Step 4: Ranking of Portfolios**
  - Cascade took the unserved demand and total system cost of all draws in each portfolio and calculated the mean and VaR of the portfolios. For its modeling purposes, the Company defines VaR as the 99th percentile of unserved demand and 95th percentile of total system cost. This is a generally-accepted methodology for determining a reasonable worst-case scenario for risk analysis. Cascade ranked its portfolios by first giving preference to any portfolio that fully solved for unserved demand in both stochastic and deterministic analysis. After that, portfolios were ranked based on a risk-adjusted total system cost metric, which gives 75% weight to the total system cost under deterministic conditions for a given portfolio, and 25% weight to the costs under stochastic conditions. Cascade believes the top ranked portfolio is the one with the most reasonable least cost and least risk mix of reliable energy supply resources and energy efficiency for Cascade and its customers. This is now deemed to be the Top Ranked Candidate Portfolio, a term that Cascade will use often in this chapter to represent the portfolio that appears to be optimal under expected conditions. It is important to note that it is still just a Candidate Portfolio until it has passed a rigorous scenario and sensitivity analysis, after which point it will become the Preferred Portfolio for Cascade over the 20-year planning horizon.

- **Step 5: Stochastic Scenarios of Top Ranked Candidate Portfolio**
  - Cascade created seventeen different traditional scenarios, and four extreme scenarios, to stochastically test its top ranked candidate portfolio. These scenarios, which are detailed in Figure 10-3, measure how the portfolio performed in high and low growth environments, as well as under

various restrictions related to storage availability. In each scenario, the portfolio was run through a 10,000 draw Monte Carlo weather simulation, and the total system cost at the 99th percentile was recorded as the VaR for the portfolio in that scenario.

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

- **Step 7: Sensitivity Testing of Top Ranked Candidate Portfolio**
  - Cascade created seven different pricing environments to stochastically test its Top Ranked candidate portfolio. These sensitivities, which are detailed in Figure 10-4 measure how the portfolio performed in high and low price situations, as well as with a range of adders related to carbon legislation. In each sensitivity, the portfolio was run through a 10,000 draw Monte Carlo price simulation, and the total system cost at the 95th percentile was recorded as the VaR for the Candidate Portfolio in that sensitivity.

- **Step 8: Sensitivity Analysis of Top Ranked Candidate Portfolio**
  - Similar to comparing the scenarios in Step 6, the VaR of the Top Ranked Candidate Portfolio in each sensitivity was compared to the Company's VaR limit, which was set by Cascade's GSOC and was equal to 1.25 times the mean total system cost of the portfolio under expected conditions. If the VaR in any sensitivity exceeded this limit, that portfolio may be rejected, and the next highest ranked portfolio would become the new Top Ranked Candidate Portfolio for scenario analysis. If the VaR of all sensitivities did not exceed this limit, the portfolio passed sensitivity testing and could be confirmed as Cascade's Preferred Portfolio. Figure 10-2 displays this process as a flowchart.

Figure 10-2: Supply Resource Optimization Process Flow Chart

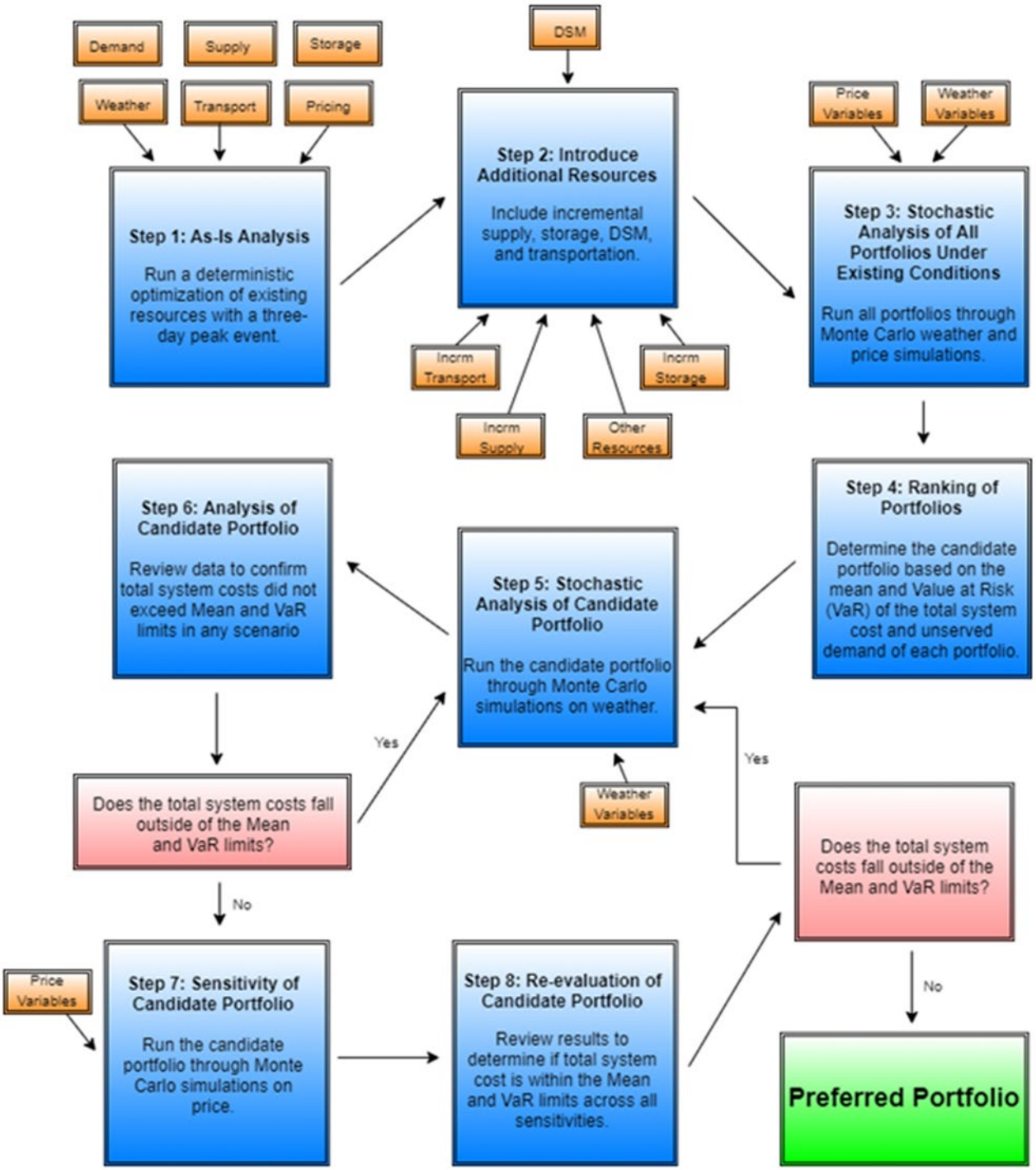


Figure 10-3: Breakdown of Scenarios Modeled

Scenarios		Assumptions					First Year Unserved
		Growth	Weather	Price	Carbon Forecast	Constraints	
Expected Conditions		Medium Load Growth	Stochastic Weather	Stochastic Pricing	SCC w/ 2.5% Discount Rate	None	N/A
Transportation	No Evergreen	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No Current Contracts Evergreen	2032
Growth	High Growth	High Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	None	
	Low Growth	Low Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	None	
Extreme Scenarios	No Alberta Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No gas from Alberta	
	No BC Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No gas from British Columbia	2021
	No Canadian Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No gas from Canada	2021
	No Rockies Supply	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No gas from Rockies	
Limit Supply	Limit Alberta	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No day gas from Alberta	2024
	Limit BC	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No day gas from British Columbia	
	Limit Rockies	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No day gas from Rockies	2025
	Limit Canada	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No day gas from Canada	
No Storage	No JP	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No access to Jackson Prairie	
	No Plymouth	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No access to Plymouth storage	
	No Mist	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No access to Mist storage	
	No Storage	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	No access to any storage	2022
Limit Storage	Limit JP	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	25% access to Jackson Prairie	
	Limit Plymouth	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	25% access to Plymouth storage	
	Limit Mist	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	25% access to Mist storage	
	Limit Storage	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	25% access to any storage	2033
RNG	On System RNG	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	Must take RNG supply injected on Cascade's system	
	Off System RNG	Medium Load Growth	Stochastic Weather	Medium Pricing Environment	SCC w/ 2.5% Discount Rate	Must take RNG supply injected off Cascade's system	

Figure 10-4: Breakdown of Sensitivities Modeled

Sensitivities		Assumptions					First Year Unserved
		Growth	Weather	Price	Carbon Forecast	Constraints	
Expected Conditions		Medium Load Growth	Stochastic Weather	Stochastic Pricing	SCC w/ 2.5% Discount Rate	None	N/A
Environmental Adder	0%	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 0% Environmental Adder	SCC w/ 2.5% Discount Rate	None	
	20%	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 20% Environmental Adder	SCC w/ 2.5% Discount Rate	None	
	30%	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing with a 30% Environmental Adder	SCC w/ 2.5% Discount Rate	None	
Carbon Forecasts	Raise Wages, Cut Carbon	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	House of Representatives Raise Wages, Cut Carbon Proposal	None	
	Cap and Trade	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	Market driven carbon pricing based on a Cap and Trade system	None	
	Market Choice	Medium Load Growth	Average Weather with Peak Event	Stochastic Pricing	House of Representatives' Market Choice Proposal	None	
Price Forecast	High Price Forecast	Medium Load Growth	Average Weather with Peak Event	Stochastic High Pricing Environment	SCC w/ 2.5% Discount Rate	None	

While Chapter 13 includes a full glossary, terms related to Figure 10-3 and 10-4 are shown below for convenience.

Terms Used in Figure 10-3 and 10-4

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

Stochastic Weather – The weather pattern was modeled using historical weather data in each of Cascade's climate zones. This data is run through a Monte Carlo simulation, which allows the Company to derive the 99th percentile of potential system weighted heating degree days (HDDs).

No Evergreen – A transportation constraint where Cascade models the impact of not renewing any contracts with a termination date before the end of the 20-year planning horizon.

Low Customer Growth – Low customer growth scenarios were created by examining the low end of the confidence intervals of Cascade's customer forecast, as mentioned on page 3-18.

Medium Customer Growth – Cascade used its expected customer forecast, as mentioned on page 3-18 for the expected growth scenario.

High Customer Growth – High customer growth scenarios were created by examining the high end of the confidence intervals of Cascade's customer forecast, as mentioned on page 3-18.

Medium Pricing Environment – Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from multiple sources over the 20-year planning horizon.

Stochastic Pricing – NYMEX Pricing was modeled by running Cascade's price forecast through a Monte Carlo simulation, which allows the Company to identify the 95th percentile of potential NYMEX pricing based on the deterministic projections.

Stochastic High Pricing Environment – NYMEX Pricing was modeled by running Cascade's price forecast through a Monte Carlo simulation, which allows the Company to identify the 95th percentile of potential NYMEX pricing based on the deterministic projections. Prices were then increased by 5% at all markets to simulate a high pricing environment over the 20-year period.

Stochastic Pricing with 0% Adder – Price was modeled using Cascade's price forecast, which was derived by weighting the forecasts from its sources over the 20-year planning horizon. Cascade then removed the 10% environmental adder, originally in place to simulate the impact of unforeseen environmental conditions.

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

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

Cap and Trade – This was modeled as an adder to Cascade 20-year price forecast and avoided cost starting in 2021. The Company used the California Energy Commission's Integrated Energy Policy Report (IERP) 2019 Preliminary GHG Allowance Price Projection[1] as a proxy for the projected pricing of an Oregon Marketplace.

SCC w/ 2.5% Discount Rate – This was modeled as the base case for the 2020 IRP, as an adder to Cascade's 20-year price forecast and avoided cost

[1] *See* 2019 IEPR Preliminary GHG Allowance Price Projections
Energy Assessment Division 3-13-19 (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03)

starting in 2021. The source of this forecast was the Interagency Working Group on Social Cost of Greenhouse Gases' Technical Support Document: Technical Update of the Social Cost of Carbon (SCC) for Regulatory Impact Analysis Under Executive Order 12866.[2]

House of Representatives' Market Choice Proposal – A carbon sensitivity based on the proposed carbon tax that was introduced to the U.S. House of Representatives on January 24, 2019 (H.R. 763).[3] The proposal is not expected to pass but is a good proxy for a potential national tax. This was modeled as an adder to Cascade's 20-year price forecast and avoided cost starting in 2020.

House of Representatives' Raise Wages, Cut Carbon Act – A carbon sensitivity based on the proposed carbon tax that was introduced to the U.S. House of Representatives on July 25th, 2019 (H.R. 3996).[4] The proposal is not expected to pass but is a good proxy for a potential national tax. This was modeled as an adder to Cascade's 20-year price forecast and avoided cost starting in 2020.

Must Take On-System RNG – This is a hypothetical renewable natural gas resource that is inserted into the scenario at the zonal level, meaning no additional upstream capacity is needed to inject the supply at a citygate. Pricing, quantity, and timing of the resource, as well as the impact of this resource, is discussed further in Chapter 8, Renewable Natural Gas.

Must Take Off-System RNG – This is a hypothetical renewable natural gas resource that is inserted into the scenario at the supply basin level, meaning additional upstream capacity is needed to inject the supply at a citygate. Pricing, quantity, and timing of the resource, as well as the impact of this resource, is discussed further in Chapter 8, Renewable Natural Gas.

Planning and Modeling

SENDOUT® has broad capabilities that allow the Company to develop supply and demand relationships that closely mirror Cascade's existing operations. Figure 10-5 shows the location of these pipeline zones. These pipeline zones reflect Cascade's customers being served from either Northwest Pipeline LLC (NWP) or Gas Transmission Northwest (GTN) interstate pipeline facilities.

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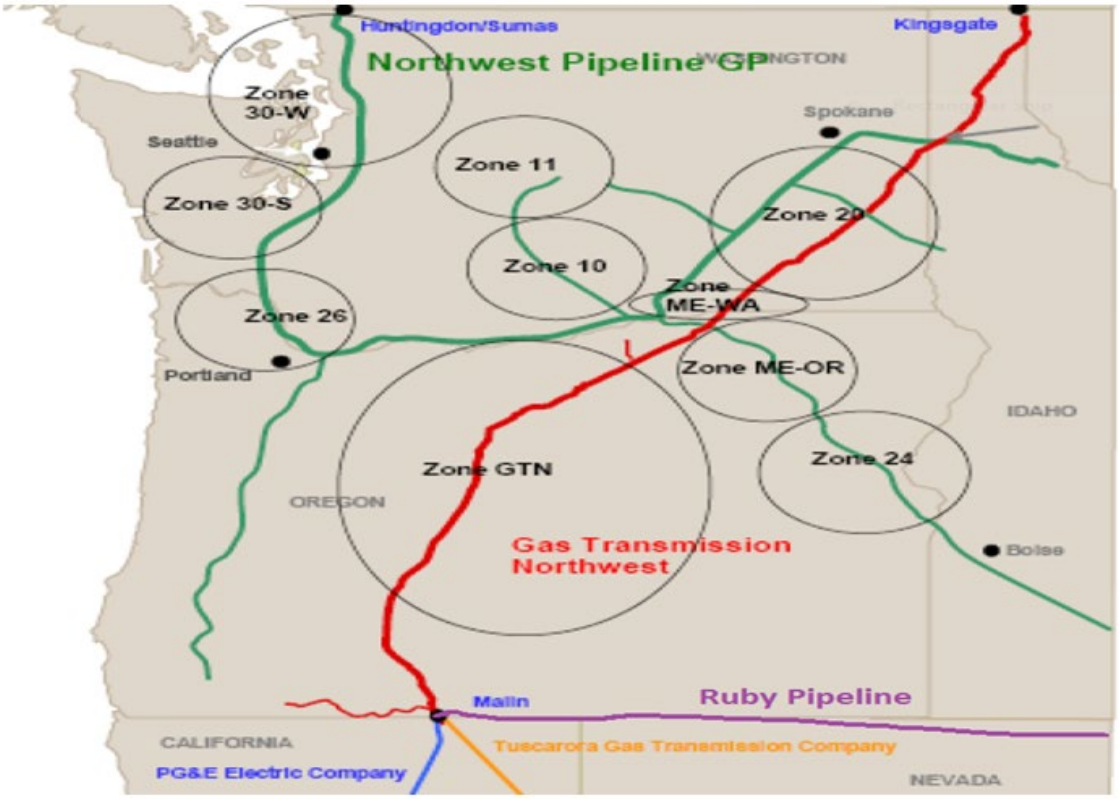
[2] *See* Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866 (https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf)

[3] *See* H.R.763 - Energy Innovation and Carbon Dividend Act of 2019 (https://www.congress.gov/bill/116th-congress/house-bill/763/text)

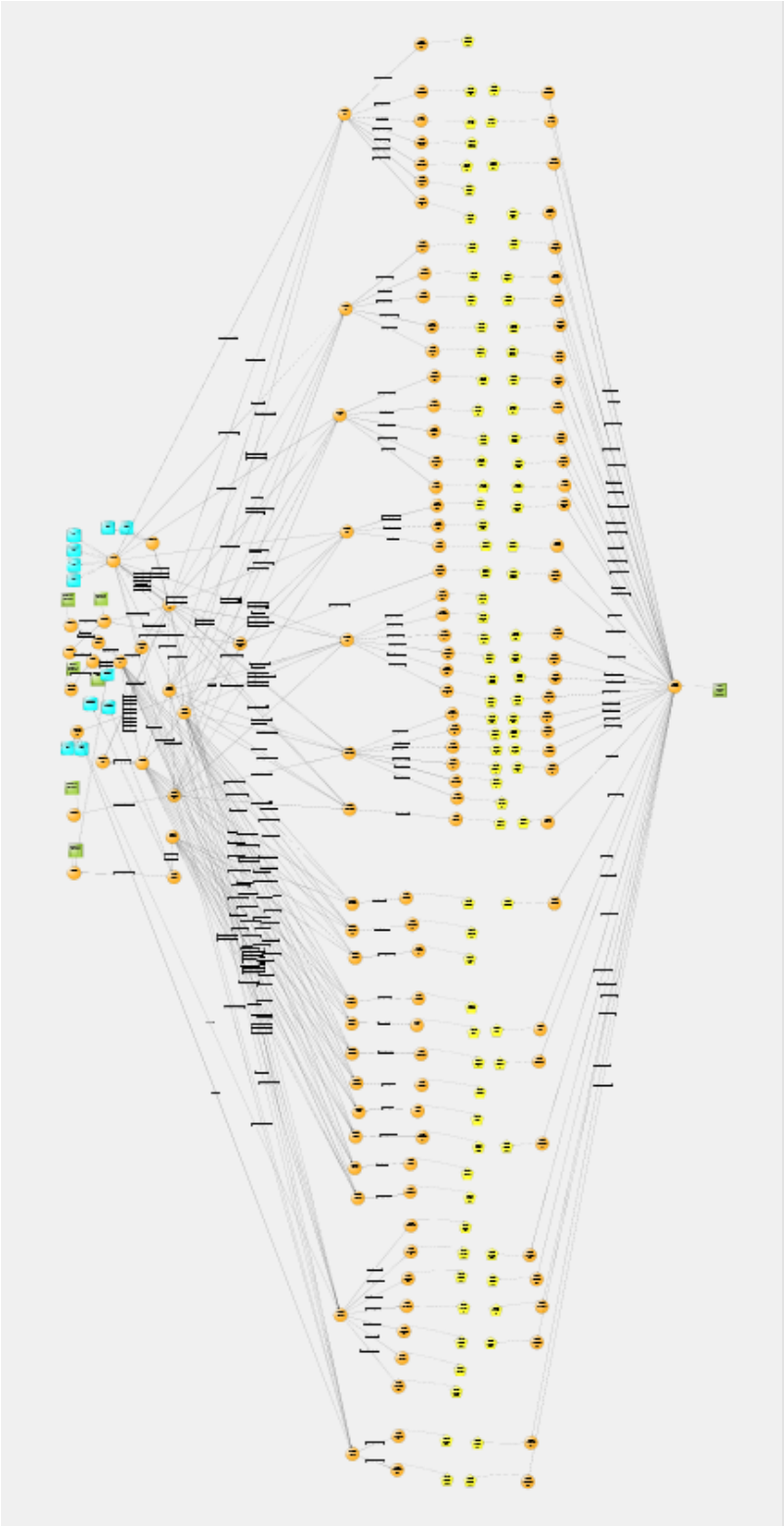
[4] *See* H.R.3996 – Raise Wages, Cut Carbon Act of 2019 (https://www.congress.gov/bill/116th-congress/house-bill/3966

Figure 10-5: Pipeline Zones Used in this IRP



With the in-house load forecast model (LFM) application, which is discussed in detail in Chapter 3, Demand Forecast, modeling dives into an even more granular level. This IRP takes more of a citygate and rate schedule view, which allows Cascade to take a deeper view of capacity shortfalls and potential constraints. A copy of the network diagram is shown in Figure 10-6. The network diagram is provided for illustrative purposes to emphasize the difficulties in configuring the model to best replicate Cascade's complex system rather than being provided for its readability.

Figure 10-6: SENDOUT® Network Diagram of Cascade's System



Stochastic Methodology Discussion

Cascade runs its Monte Carlo simulations on all candidate portfolios, which are used to create the risk-adjusted metrics discussed in Step 4 of Cascade's supply resource optimization process. The rationale behind this is to use the deterministic results to capture the intrinsic value of each portfolio, while the stochastic results capture the extrinsic value of the portfolios. Cascade chose to weight these with a 75/25 split, as the Company believes this mix properly assigns value to results under expected conditions versus results under unexpected conditions. Additionally, this follows the regional best practices.

The Company has moved from using the Monte Carlo functionality within SENDOUT® to building its own simulation engine in R. While SENDOUT® was able to generate adequate results in the past, the Company wanted to run a more robust simulation to supplement the functionality of SENDOUT®. SENDOUT® ran Monte Carlo simulations on monthly data and then used historical patterns to create weather patterns. This methodology allows Cascade to be more detailed by running Monte Carlo simulations on daily data and creating multiple weather patterns. The new methodology of utilizing R to run stochastic analysis allows Cascade to be transparent on each step of the stochastic analysis process. Using historical data for weather, along with Cholesky decomposition matrices, Cascade can now run a 10,000 draw Monte Carlo simulation on price and weather, which will allow for a more accurate distribution when identifying what is the 99th percentile of price and weather for stochastic analysis. The negative aspect of running stochastic analysis outside of SENDOUT® is that Cascade needs to manually insert the weather data of a specific stochastic analysis draw to run the linear optimization of that weather profile. The Monte Carlo functionality embedded within SENDOUT® allows the program to read and optimize the stochastic weather results from all generated draws automatically.

The Cholesky decomposition matrix is a positive-definite covariance matrix. This matrix is used to draw or sample random vectors from the N-dimensional multivariate normal distribution that follow a desired distribution. In Cascade's case, this allows for correlations between weather zones to be included when drawing or sampling data distributions for Monte Carlo runs. Figure 10-7 shows Cascade's historical correlations between weather stations for the month of January. A realistic Monte Carlo draw would show similar correlations between weather stations, which Cascade manages to accomplish with the Cholesky Decomposition Matrix. By correlating random variables, there is always the potential issue of overfitting and not allowing for enough randomness between each draw. Also, Cascade is aware of the possibility of introducing bias into its models. Cascade is monitoring this by constantly evaluating and cross-validating the results.

Figure 10-7: January Historical Correlations between Weather Stations

City	Baker City	Bellingham	Bremerton	Pendleton	Redmond	Walla Walla	Yakima
Baker City	1.00000						
Bellingham	0.63383	1.00000					
Bremerton	0.65848	0.86889	1.00000				
Pendleton	0.70245	0.73001	0.69979	1.00000			
Redmond	0.71736	0.76293	0.76183	0.79743	1.00000		
Walla Walla	0.71051	0.72579	0.69180	0.95952	0.78995	1.00000	
Yakima	0.66974	0.69391	0.68315	0.79445	0.70062	0.81950	1.00000

Stochastic analysis of price presents a different set of challenges. Cascade performs its Monte Carlo simulation on each of its basins, correlating the simulation results to each other similar to how weather is correlated. Prices also follow a different distribution from weather, which adds a layer of complexity. HDDs have historically shown to be distributed normally, which allows for the use of Gaussian distributions in weather stochastic analysis, and while the month to month percentage changes in gas prices are shown to be normally distributed, gas prices tend to follow a more lognormal distribution. Practically speaking, prices appear to be just as likely to move up or down month over month, but the dollar impact of these movements is greater for price increases. For example, with a starting price of $2/dth, five straight months of 10% gains result in an increase of $1.22/dth, while five straight months of 10% losses result in a loss of $0.82/dth.

Cascade models these price movements with a Geometric Brownian motion stochastic process. For each of its 10,000 draws, the month over month price change is determined by two elements: a drift term and a shock term. The drift term is the expected movement of the basin pricing, derived from the Company's price forecast. The shock term is the main stochastic element, which takes the month over month return variance and multiplies it by a random normal variable to create a normal distribution of price movements for a given month, and a lognormal distribution of prices as illustrated above.

A more in-depth breakdown of the data justifying this new methodology, including the monthly present value revenue requirement (PVRR) calculations of a sampling of stochastic draws, can be found in Appendix G.

Resource Optimization Output and Analysis Reports

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

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

Key Output Report - Cost and Flow Summary

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

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

Key Output Report - Month to Month Summary

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

during the winter, the analyst can introduce seasonal resources to SENDOUT® to determine whether it would choose them over the annual supplies already available in the portfolio.

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

Key Output Report - Supply vs. Requirements

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

Key Output Reports - Custom Report Writer

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

Key Inputs

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

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

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

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

Resource mix is one of the more powerful and highly desirable input tools available in the model. By toggling on resource mix and providing an MDQ maximum and minimum, the analyst directs SENDOUT® to appraise the supply contract, on a total

cost basis, against all other supply resources available within the portfolio. Under resource mix, SENDOUT® will determine whether the resource is desirable within the portfolio and at what MDQ size, within the MDQ maximum and minimum, the resource should be made available within the portfolio. This aspect of SENDOUT® is crucial to the evaluation of potential resources, as the Company conducts its resource planning, appraisal, and acquisition activities.

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

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

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

Decision Making Tool

Analysis of optimization model results and other operational and contractual constraints allows Cascade to make more informed resource decisions. The IRP optimization model output and Monte Carlo simulation analysis provide the quantifiable output from numerous model inputs. The model does not prescribe the ultimate resource portfolio. It can only calculate the least cost set of resources given

their specific pricing and quantifiable constraint characteristics. However, many other resource combinations may be available over the planning horizon. Therefore, Cascade must include subjective risk judgments about unquantifiable and intangible issues related to resource selections. These include future flexibility, supplier deliverability risk, pipeline(s) risk, financial risk to the utility and its customers, operational constraints, regulatory risk, etc. The risk judgments are combined with the quantitative IRP analyses to form the actual resource decisions.

Resource Integration

The following subchapters summarize the preceding chapters bringing together the demand forecast, existing supply and demand side resources and potential alternative resources to develop the 20-year, most reasonably priced reliable portfolio.

Demand Forecast

Load growth across Cascade's system through 2040 is expected to fluctuate between 0.92% and 2.19% annually, accounting for leap years. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.50% and 1.23%, while industrial expects a growth rate of approximately 1.58%. Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.56% over the planning horizon, with the Oregon portion outpacing Washington, 1.83% versus 1.24%.

Long-Term Price Forecast

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

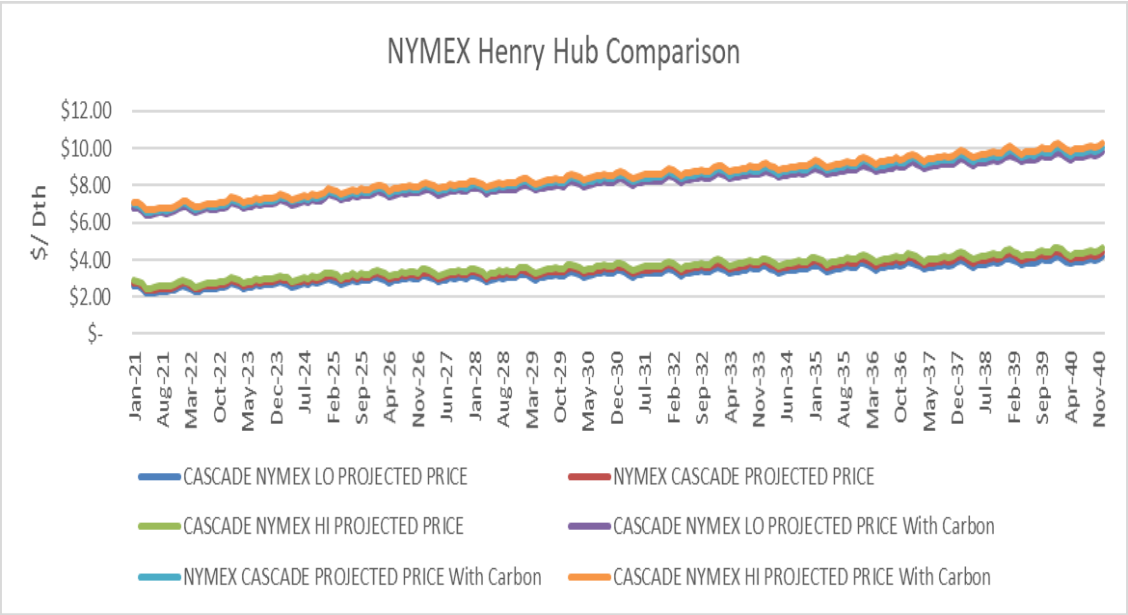
Natural gas prices have stabilized after dramatic fluctuations over the course of the last ten years. Figure 10-8 shows the history of regional and Henry Hub prices over the past ten years. The shale boom, environmental concerns around carbon,

conservation efforts, and improvements in renewable energy have led to a market with prices as low as they have been in recent history. Recently, prices have remained relatively stable due to abundant supply, with one noticeable exception occurring at the end of 2018 with the Enbridge pipeline explosion. The inability to move gas from British Columbia to the U.S. Pacific Northwest created extreme upward pricing pressure across the region, and specifically at the Sumas basin. Once the pipeline was repaired and pricing stabilized by the summer of 2019.

Figure 10-8: Historical Regional Pricing for Past Ten Years

Figure 10-9 shows the comparison of ranges of pricing for the planning horizon, including the expected low, medium and high price, with and without a carbon adder for the impact of the Social Cost of Carbon with a 2.5% discount rate on pricing.

Figure 10-9: NYMEX Annual Price Comparison



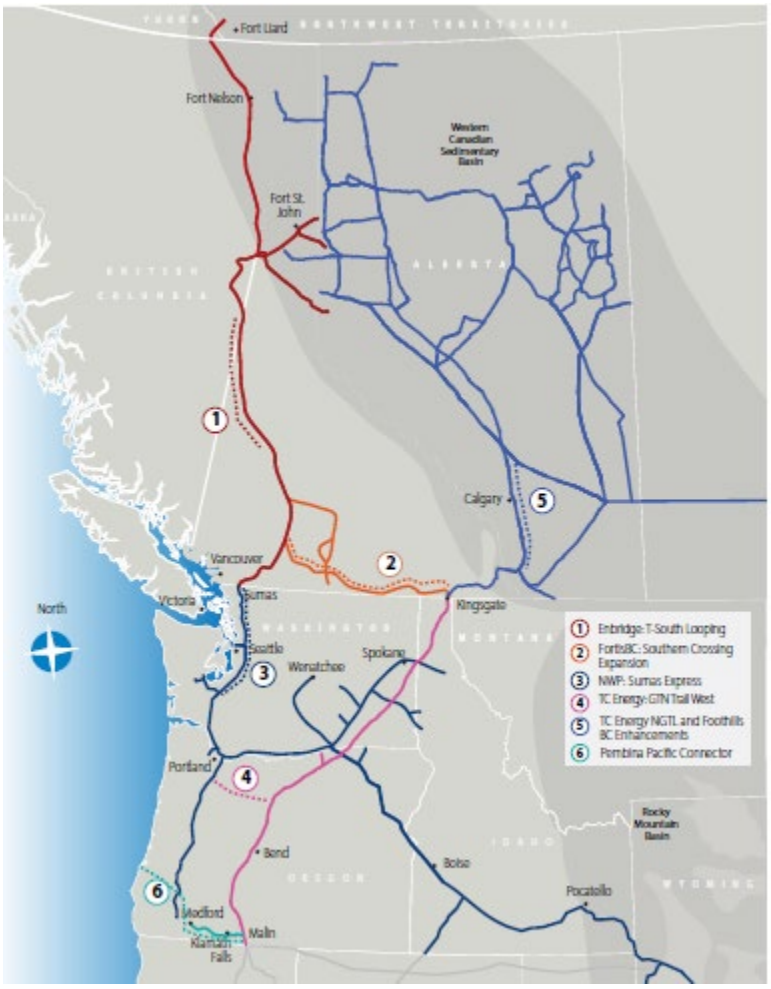
Environmental Adder

As discussed in Chapter 5, Avoided Cost, Cascade included a 10% environmental adder in its 2020 IRP's 20-year price forecast.

Transportation/Storage

Chapter 4, Supply Side Resources, describes the range of current upstream pipeline transportation capacity and storage services under contract to serve core customers. Additionally, the Company identified several proposed transportation resources, as seen in Figure 10-10, such as a potential expansion of NWP along the I-5 corridor and acquiring currently unsubscribed GTN capacity that can be used to meet customer growth and address potential capacity shortfalls. The Company also continues to work with NWP to look at re-aligning Cascade's contracted delivery rights (Maximum Daily Delivery Obligations, or MDDOs) to citygates with potential peak day capacity shortfalls. The Company also uses segmenting pipeline capacity as a way to maximize the utilization of Cascade's capacity. These resources, plus leasing incremental storage at several regional facilities, were all considered as a resource mix of possibilities to form the Company's 20-year integrated resource portfolio.

Figure 10-10: Alternative Transportation Resources[5]



Demand Side Management

Chapter 7, Demand Side Management, describes the methodology used to identify energy efficiency potential and the interactive process that utilizes avoided cost thresholds for determining the cost effectiveness of energy efficiency measures on an equivalent basis with supply side resources. For the 2020 IRP the nominal system avoided costs ranges between $0.79/therm and $1.09/therm over the 20-year planning horizon. Through the cost-effective use of conservation programs, the Company is able to reduce the load demand that otherwise must be met by more costly supply resources, such as a pipeline capacity expansion.

Cascade's DSM forecast is incorporated into its optimization modeling by converting the heat and base load forecasts into a peak and non-peak DSM factor. The peak day factor is the ratio of forecasted peak day demand to annual demand, while the

[5] Northwest Gas Association (NWGA) 2020 Pacific Northwest Gas Market Outlook 2020

non-peak factor is equal to one divided by the number of days in that year. These values are then allocated to the pipeline zonal level and loaded into SENDOUT® to model the impact of conservation on resource acquisition needs. From a technical standpoint this is done by creating a must-take resource that acts like a supply at the zonal level equal to the peak and non-peak DSM values. While it is not actually a supply, this methodology tells SENDOUT® to use DSM to decrement demand by the forecasted energy efficiency quantities before any resource acquisition decisions are made.

Results

After incorporating these inputs into the SENDOUT® model, Cascade analyzed the demand compared to the existing resources as well as the demand against various portfolios of available resources. This served as the foundation for the Company to see what resources are taken to meet system demand with the least cost, lowest risk mix of natural gas supply and energy efficiency. For the first time in recent IRP history, Cascade is not forecasting any potential shortfalls over the entire planning horizon in its As-Is modeling. This is in large part a function of an additional 10,000 dth/day of GTN, 20,000 dth/day of NGTL, and 10,000 dth/day of Foothills capacity acquired in late 2019, which allows the Company to flow additional gas to central Oregon citygates that had forecasted shortfalls in previous IRPs. This capacity is anticipated to be in-service and added to Cascade's portfolio in 2023 and can be seen in Appendix E. It is important to note that this does not remove the necessity of the resource optimization process, as often times there may be additional resources that can be acquired to solve Cascade's goal of finding its least cost, least risk resource mix. A good example of this is the evaluation of additional capacity on the NGTL/Foothills systems near Alberta. Often times, AECO gas is cheaper than gas from Sumas or Rockies, so the Company must evaluate whether it is cost-effective to acquire the capacity to move more gas from AECO, at the expense of the reservation and demand charges associated with this capacity. Because of the complexity of Cascade's system, it is impossible to perform this analysis without the help of an optimization tool like SENDOUT®.

Portfolios Evaluated

For the 2020 IRP, Cascade elected to evaluate seven potential portfolios. These portfolios represent a wide variety of potential solutions for Cascade's resource deficiency, with an evaluation of all available resources in the Pacific Northwest for natural gas. Unlike electric utilities, who have a variety of options for power generation (hydro, wind, solar, etc.), Cascade is limited to a single resource, natural gas, which hinders the scope of potential portfolio analysis. The Company selected these seven portfolios after discussions with various stakeholders throughout its technical advisory group process. In future IRPs, Cascade will consider evaluating additional portfolios.

Figure 10-11 outlines the key components of each portfolio identified in Figure 10-1. SENDOUT® deterministically selects the optimal quantity of each resource based on its Resource Mix functionality. These quantities, which are provided in Appendix E, are then tested stochastically, and ranked in order of unserved demand and total system cost.

Figure 10-11: Resource Composition of All Evaluated Portfolios

	All-In	All-In Less DSM	NWP Only	NWP + Storage	GTN	GTN + Storage	Storage Only
Incremental NGTL							
Incremental Foothills							
Incremental GTN N/S							
I-5 Mainline Exp.							
Wenatchee Lateral Exp.							
Spokane Lateral Exp.							
Eastern OR Mainline Exp.							
Incremental Opal							
Incremental GTN S/N							
Incremental Ruby							
T-South Southern Crossing							
Trail West							
Pacific Connector							
Spire Storage							
AECO Hub Storage							
Clay Basin Storage							
Gill Ranch Storage							
Wild Goose Storage							
Incremental DSM							

Legend	
	Selected resource for the portfolio
	Considered but not selected resource
	Not considered for the portfolio

Figure 10-12 uses the mean and VaR of the total system cost and unserved demand of the portfolios considered to calculate the risk adjusted value of each portfolio. Given Cascade's mission to serve its customers, portfolios are first evaluated on unserved demand, and then mean total system cost.

Figure 10-12: Final Ranking of Portfolios – Mean and VaR

	Deterministic		Stochastic		Risk Adjusted Results	
Portfolio	Unserved Demand (DT)	Total System Cost ($000)	Unserved Demand (DT)	Total System Cost ($000)	Risk Adjusted Unserved Demand (DT)	Risk Adjusted Total System Cost ($000)
All-In	-	3,492,023	-	4,083,151	-	3,639,805
GTN + Storage	-	3,592,846	-	4,107,476	-	3,721,504
All-In Less DSM	-	3,593,146	-	4,107,451	-	3,721,722
GTN	-	3,596,248	-	4,112,461	-	3,725,302
Storage Only	-	3,590,294	-	4,096,099	-	3,716,746
NWP + Storage	-	3,590,508	-	4,096,087	-	3,716,903
NWP	-	3,593,933	-	4,101,127	-	3,720,731

Top-Ranking Candidate Portfolio

Using input from the alternative resources selected, the All-In portfolio was selected as the least cost, least risk solution for Cascade's system over the planning horizon. This portfolio is now defined as the Top-Ranking Candidate Portfolio. This portfolio provides guidance as to what resources should be considered to reduce the unserved demand with the least cost mix of all of the alternatives that the Company has considered. Furthermore, this portfolio was derived deterministically assuming average weather with a peak day event, Cascade's average price forecast, and expected growth system-wide. The impact of these resources on both unserved demand and Cascade's resource mix is shown graphically in Figures 10-13 through 10-16.

Figure 10-13: Annual Supply Take vs Demand – Top Ranked Candidate Portfolio

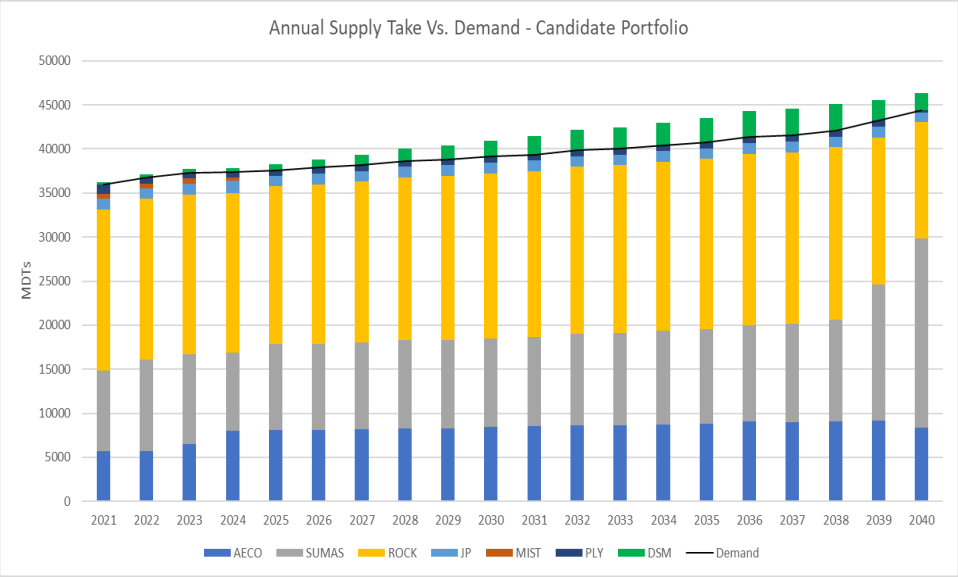


Figure 10-14: Peak Day Supply Take vs Demand – Top Ranked Candidate Portfolio

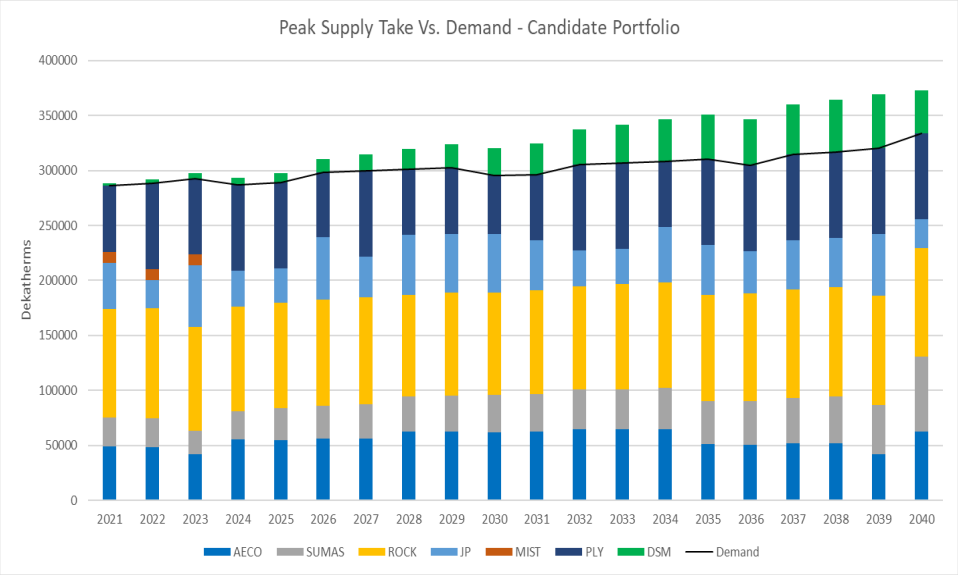


Figure 10-15: Annual Transport vs Demand –Top Ranked Candidate Portfolio

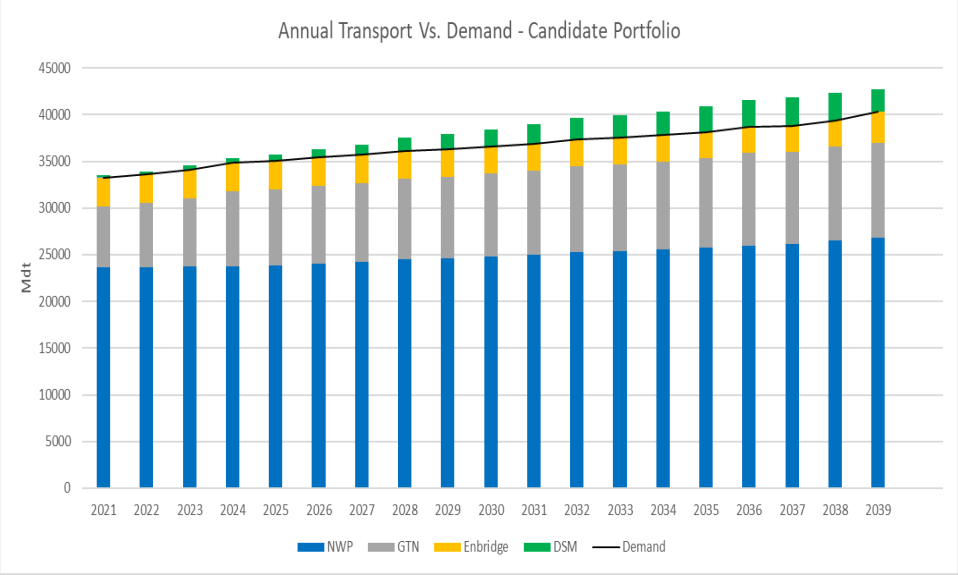
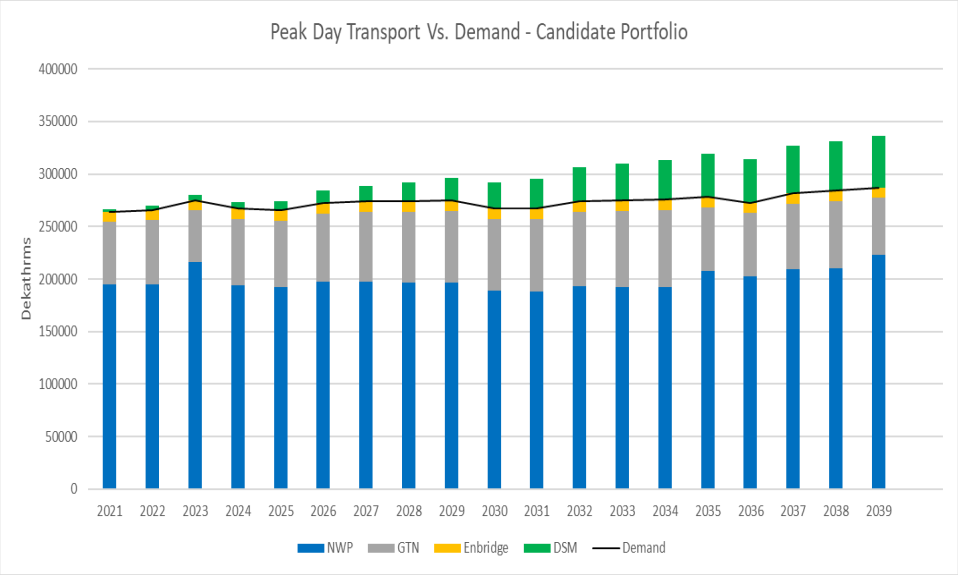


Figure 10-16: Peak Day Transport vs Demand – Top Ranked Candidate Portfolio



Alternative Resources Selected

The primary resource in the Top-Ranking Candidate Portfolio was incremental energy efficiency. The quantity and timing of this resource, using SCC with a 2.5% discount rate as the cost of carbon, is summarized in Figure 10-17.

Figure 10-17: Projected Cumulative Incremental DSM – in Therms

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	471,164	974,111	1,578,956	1,664,485	2,844,476	4,088,454	5,395,325	6,764,328	8,393,160	10,067,040
Commercial	498,905	930,610	1,420,034	2,009,041	3,387,777	4,763,631	6,135,739	7,512,601	9,150,274	10,783,868
Industrial	79,578	155,218	254,159	354,002	479,934	606,423	728,910	849,812	965,438	1,075,362
Total	1,049,647	2,059,939	3,253,148	4,027,528	6,712,187	9,458,508	12,259,974	15,126,741	18,508,872	21,926,270

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Residential	11,743,786	13,372,059	14,908,466	16,283,004	17,526,175	18,628,570	19,593,238	20,549,194	21,381,778	22,120,024
Commercial	13,515,456	15,038,830	16,386,460	17,578,046	18,598,487	19,418,437	20,114,312	20,707,027	21,190,089	21,585,060
Industrial	1,176,772	1,268,979	1,347,877	1,419,439	1,483,832	1,542,668	1,596,719	1,647,172	1,691,860	1,734,372
Total	26,436,013	29,679,868	32,642,803	35,280,489	37,608,494	39,589,675	41,304,269	42,903,393	44,263,727	45,439,456

In an effort to mitigate the risk around the uncertain nature of DSM potential, particularly with the major role energy efficiency has in the Company's Top-Ranking Candidate Portfolio, Cascade has evaluated the impact of different carbon futures on DSM. The results of this analysis are presented in Figure 10-18.

Figure 10-18: Analysis of Alternative Carbon Futures – in Therms

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCC w/ 2.5% Discount	1,049,647	2,059,939	3,253,148	4,027,528	6,712,187	9,458,508	12,259,974	15,126,741	18,508,872	21,926,270
Cap and Trade	882,218	1,729,964	2,756,515	3,370,666	5,702,977	8,116,942	10,604,337	13,174,753	16,204,473	19,280,163
% Change	-16%	-16%	-15%	-16%	-15%	-14%	-14%	-13%	-12%	-12%
Market Choice	821,733	1,609,871	2,568,400	3,097,757	5,169,009	7,331,476	9,576,666	11,913,918	14,644,627	17,422,266
% Change	-22%	-22%	-21%	-23%	-23%	-22%	-22%	-21%	-21%	-21%
Raise Wages	897,529	1,760,511	2,804,538	3,440,924	5,843,046	8,325,823	10,881,071	13,518,404	16,629,574	19,784,978
% Change	-14%	-15%	-14%	-15%	-13%	-12%	-11%	-11%	-10%	-10%

Scenario	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
SCC w/ 2.5% Discount	26,436,013	29,679,868	32,642,803	35,280,489	37,608,494	39,589,675	41,304,269	42,903,393	44,263,727	45,439,456
Cap and Trade	22,302,342	25,185,561	27,847,043	30,237,390	32,369,612	34,202,349	35,808,051	37,329,465	38,602,398	39,704,411
% Change	-16%	-15%	-15%	-14%	-14%	-14%	-13%	-13%	-13%	-13%
Market Choice	20,162,361	22,791,032	25,234,970	27,444,785	29,433,714	31,157,907	32,684,628	34,154,008	35,391,230	36,466,536
% Change	-24%	-23%	-23%	-22%	-22%	-21%	-21%	-20%	-20%	-20%
Raise Wages	22,879,884	25,825,191	28,538,476	30,968,511	33,129,547	34,982,190	36,601,092	38,130,603	39,408,445	40,513,953
% Change	-13%	-13%	-13%	-12%	-12%	-12%	-11%	-11%	-11%	-11%

While this analysis does present a substantive delta, sensitivity testing of the Top-Ranked Candidate Portfolio provides some insight into the impact of these reduced therm savings to the Company's ability to serve its customers while not exceeding established risk tolerances. The results of this analysis can be seen in Figure 10-19.

Alternative Resources Not Selected

The SENDOUT® model did not select the following resources for the Top-Ranking Candidate Portfolio:

Upstream Transport

- Incremental GTN – At this time the additional Oregon capacity expected in 2023, in conjunction with incremental energy efficiency, offsets the need for more GTN capacity.
- Incremental I-5 Capacity –The Company does not forecast a need for additional I-5 capacity at this time because of the Bremerton-Shelton realignment Cascade discussed in Chapter 4, Supply Side Resources. Cascade will continue to monitor growth in Western Washington, as prior IRPs have identified the region as an area with potential shortfalls in the future.
- Incremental Foothills – Since the Company has more capacity on Foothills versus NGTL, Cascade would need to identify a significant amount of additional NGTL capacity needed before its modeling would recommend additional Foothills capacity.
- Incremental Ruby/Turquoise Flats – Without a need for additional capacity on GTN, Cascade does not need incremental capacity on Ruby and at Turquoise Flats to move supplemental gas to GTN.

- Wenatchee Expansion – Cascade's SENDOUT® modeling identified no forecasted shortfalls in central Washington in its As-Is analysis, and no cost savings from acquiring additional capacity in this region. As a result, a Wenatchee expansion is not required at this time.
- Zone 20 Expansion – Cascade's SENDOUT® modeling identified no forecasted shortfalls in eastern Washington in its As-is analysis, and no cost savings from acquiring additional capacity in this region. As a result, a Zone 20 expansion is not required at this time.
- Incremental Starr Road – SENDOUT® determined that with Cascade's current price forecast it did not make sense to purchase incremental upstream capacity to move AECO gas from GTN to NWP.
- Eastern Oregon Expansion – Cascade's SENDOUT® modeling identified no forecasted shortfalls in eastern Oregon in its as-is analysis, and no cost savings from acquiring additional capacity in this region. As a result, an eastern Oregon expansion is not required at this time.
- T-South Southern Crossing – SENDOUT® determined that based on Cascade's current price forecast it did not make sense to purchase incremental upstream capacity to move in either direction along the Canadian border.
- Trails West (Palomar) – SENDOUT® determined that with Cascade's current price forecast, it did not make sense to purchase incremental capacity to move in either direction across central Oregon.

Supply

- Opal Incremental – Since SENDOUT® determined there was no need for incremental Ruby capacity, there is no need to purchase additional gas to move along Ruby.
- Pacific Connector - Cascade's market intelligence determined that at this time, the Pacific Connector would not create a significant enough impact on liquidity at Malin to impact Cascade's modeling.

Storage

- Gill Ranch, Clay Basin, Wild Goose, AECO Hub– No incremental storage was selected. None of these storage facilities modeled were cost effective or led to an increase in served demand. The primary reason appears to be that each storage facility modeled required long-term incremental transportation.
- Spire Storage – The Company's modeling identified this as a potentially cost-effective resource, but Cascade's market intelligence indicates that Spire does not currently have available capacity. The Company will monitor Spire's capacity offerings for opportunities to acquire this resource in future IRPs.

Portfolio Evaluation: Additional Scenario/Sensitivity Analyses

Figure 10-19 summarizes the net present value of the PVRR of all additional demand scenarios and sensitivities reviewed. After the Candidate Portfolio was selected, the Company tested it stochastically through various extreme situations, which are further explained in Appendix E. As discussed during Cascade's Supply Resource Optimization Process, the objective of this analysis is to ensure that the costs of the Candidate Portfolio do not exceed the VaR limit in any of the scenarios/sensitivities discussed in Figure 10-3 and 10-4. The results of all scenarios are also shown graphically in Figures 10-20 and 10-21.

Figure 10-19: Total System Cost and Average Cost/Served Therm of Additional Scenarios/Sensitives

Scenario	Total System Cost ($000)	$/Therm Served	Distance from VaR Limit ($000)	Unserved Start Year	Total Therms Unserved
Raise Wages, Cut Carbon	3,699,953	0.4813	849,540	N/A	N/A
Cap and Trade Carbon Forecast	3,691,584	0.4802	857,909	N/A	N/A
Market Choice Carbon Forecast	3,663,054	0.4765	886,439	N/A	N/A
Price Forecast High	3,742,673	0.4868	806,819	N/A	N/A
Environmental Adder 0%	3,721,462	0.4841	828,030	N/A	N/A
Environmental Adder 20%	3,761,528	0.4893	787,965	N/A	N/A
Environmental Adder 30%	3,781,354	0.4918	768,139	N/A	N/A
No Evergreen	3,816,203	0.5271	733,289	2032	706,635,518
Low Growth	3,825,655	0.5068	723,837	N/A	N/A
High Growth	4,205,058	0.5040	344,435	N/A	N/A
Limit BC	4,169,076	0.5246	380,417	N/A	N/A
No BC*	3,022,081	0.4837	1,527,412	2021	1,698,605,802
Limit Alberta	4,205,333	0.5292	344,159	N/A	N/A
No Alberta*	4,395,393	0.5533	154,100	2024	2,374,033
No Rockies*	4,920,722	0.6300	(371,230)	2026	135,654,971
Limit Rockies	4,417,382	0.5559	132,111	N/A	N/A
Limit Canada	4,464,871	0.5619	84,622	N/A	N/A
No Canada*	2,881,779	0.5226	1,667,714	2021	2,432,839,477
No Plymouth	4,093,948	0.5152	455,545	N/A	N/A
Limit Plymouth	4,073,095	0.5126	476,397	N/A	N/A
Limit JP	4,127,268	0.5194	422,224	N/A	N/A
No JP	4,168,125	0.5245	381,368	N/A	N/A
Limit Mist	4,019,504	0.5058	529,989	N/A	N/A
No Mist	4,021,987	0.5061	527,506	N/A	N/A
Limit Storage	4,205,825	0.5293	343,668	2033	570,920
No Storage	4,280,853	0.5391	268,640	2022	5,116,642
RNG #1	4,015,358	0.5053	534,135	N/A	N/A
RNG #2	4,017,026	0.5055	532,466	N/A	N/A
***Denotes Extreme Scenario, see Extreme Scenario Discussion subsection for analysis**					

VaR Limit	**4,549,493**

Figure 10-20: Total System Cost Comparison by Scenarios/Sensitivity

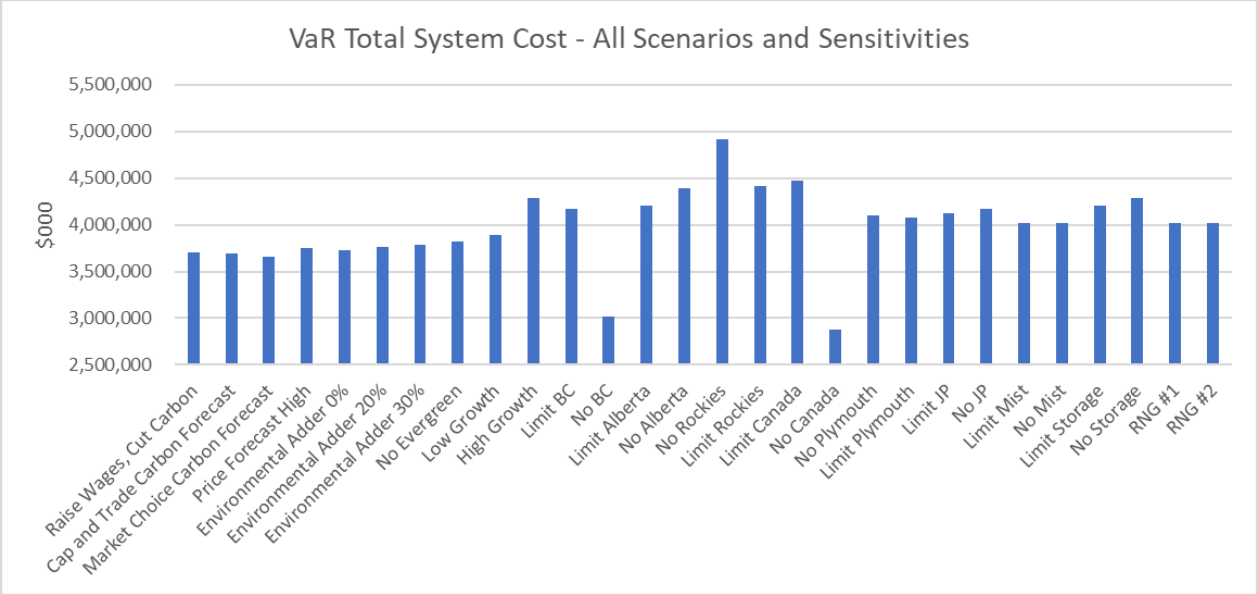
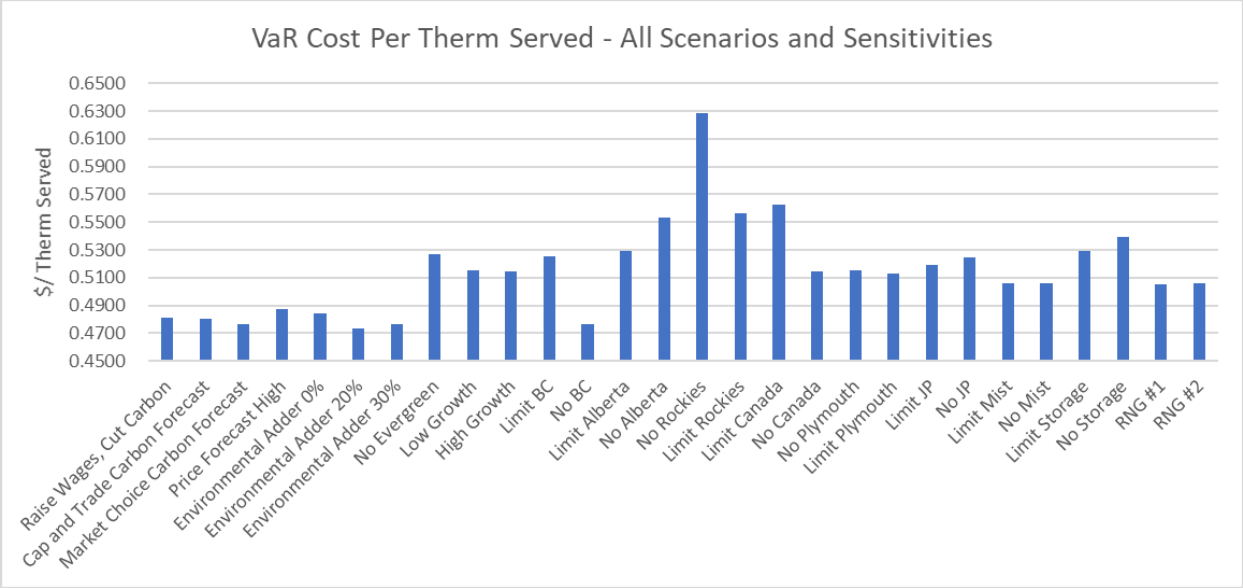


Figure 10-21: Cost per Therm Served by Scenario/Sensitivity



Holistically, one interesting conclusion to draw from this data is that Cascade's system is far more sensitive to the availability of its resources versus the cost or demand for these resources. In Figure 10-20 costs are fairly static across the scenarios and sensitives where gas prices or load are the primary variable (high/low growth and the various carbon sensitivities) but become more volatile when the ability to access one or more basins or storage facilities is limited or removed. Two

traditional scenarios in particular provide intriguing results that merit further discussion: No Evergreen and No Storage.

In Cascade's No Evergreen scenario, the Company assumes that, upon expiration, Cascade will not renew any of its upstream transportation contracts. In theory, this could provide some significant savings to Cascade's customers if the Company no longer needed to pay reservation rates on unnecessary contracts. Unfortunately, this analysis has identified that without renewing these contracts, the Company may begin to experience shortfalls starting in 2032. While this does not invalidate the Top-Ranking Candidate Portfolio, it does reinforce the necessity to review all contracts prior to expiration to evaluate if it is prudent to renew the contract, a process that the Company undertakes well before all contracts are set to terminate.

In Cascade's No Storage scenario, the Company assumes that it will no longer have access to any storage facilities as of the start of the planning horizons. Obviously, this would be problematic for a number of reasons, as storage is both a vital cost mitigation tool and a key peaking resource in high demand situations. As expected, under this scenario Cascade would experience both an increase in cost (although not above the VaR limit) and potential shortfalls almost immediately. Once again this does not invalidate the Top-Ranking Candidate portfolio as it is unrealistic to expect to lose access to all storage facilities, but it does reinforce the value of Cascade's existing storage, and the Company's desire to continue to acquire storage when cost-effective or operationally beneficial, as was the case when Cascade leased capacity at the Mist storage facility.

Extreme Scenario Discussion

New to the 2020 IRP, the Company has elected to label four of its scenarios as extreme scenarios: No Rockies, No Alberta, No BC, and No Canada. In each of these scenarios, Cascade loses the ability to purchase gas from the referenced basin. While possible for the short term, these scenarios are not meant to evaluate potential real world activities, but rather to examine how valuable access to these basins are relative to each other.

The extremely low total system costs in the No Canada and No BC scenarios are a function of Cascade's inability to serve a significant portion of its customers without Canadian gas, while the high cost of the No Rockies scenario is a result of an excessive reliance on Sumas gas when gas from the Rockies is removed from the portfolio. Finally, the No Alberta scenario's impacts are mitigated by the fact that Cascade is already limited in the amount of supply it can purchase from AECO by its existing relatively smaller share of transportation contracts from Alberta, as illustrated in Figures 10-13 and 10-14. That being said, without this gas, Cascade loses its primary resource to serve its central Oregon customers. Alberta gas also tends to be the cheapest of the three basins, which leads to a higher cost per therm served than most other scenarios/sensitivities.

While Cascade is hesitant to label scenarios as analogs to real life events, it is worth discussing the No BC scenario in the context of the 2018 Enbridge explosion. The Company's scenarios assume a permanent impact to supplies at Sumas, while the Enbridge incident only temporarily restricted access to gas in British Columbia. If such an explosion were to cause permanent damage, the data from this scenario analysis would seem to indicate that Cascade's system could survive restricted access to British Columbia supplies as evidenced in the Limit BC scenario, but would struggle to maintain the capacity to serve customers if Sumas gas were to be fully inaccessible for a sustained period of time.

Stochastic Analyses - Annual Load Requirements & Weather Uncertainty

The annual load requirements will vary dramatically based on the weather assumptions. Through the use of its new proprietary Monte Carlo functionality, the Company has the ability to analyze the impacts of stochastic weather on its load forecast. Figure 10-22 shows the daily HDD pattern at each of Cascade's seven weather stations, while Figure 10-23 compares the system weighted stochastic weather to the deterministic system weighted weather profile to emphasize the potential volatility of weather that is captured in stochastic analysis.

Figure 10-22: Stochastic HDDs by Weather Station

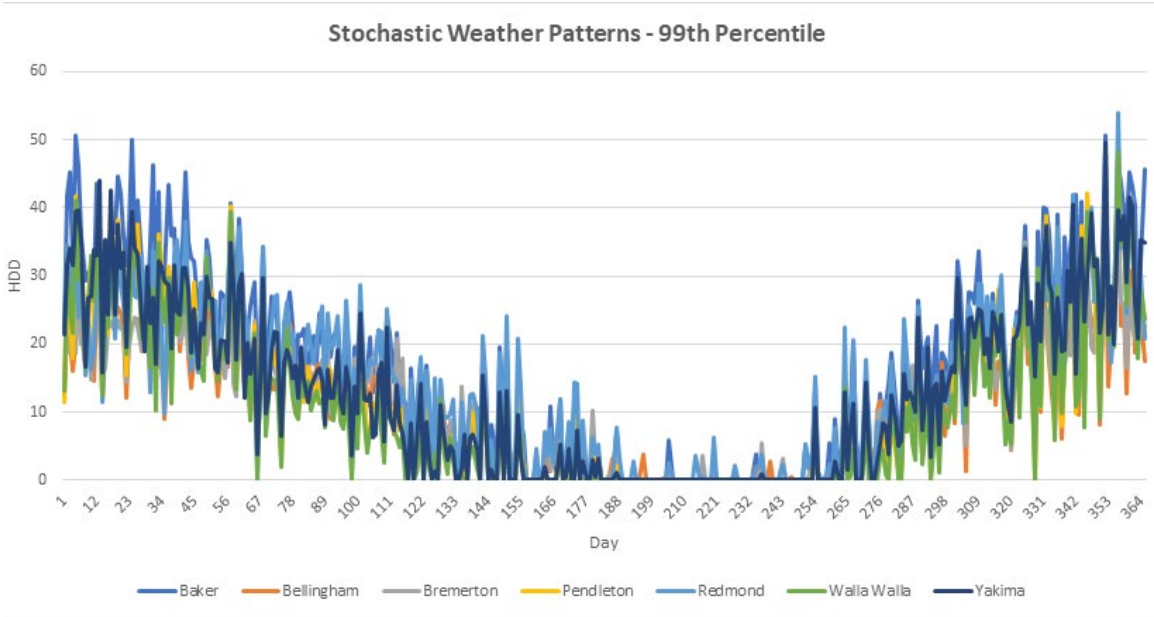
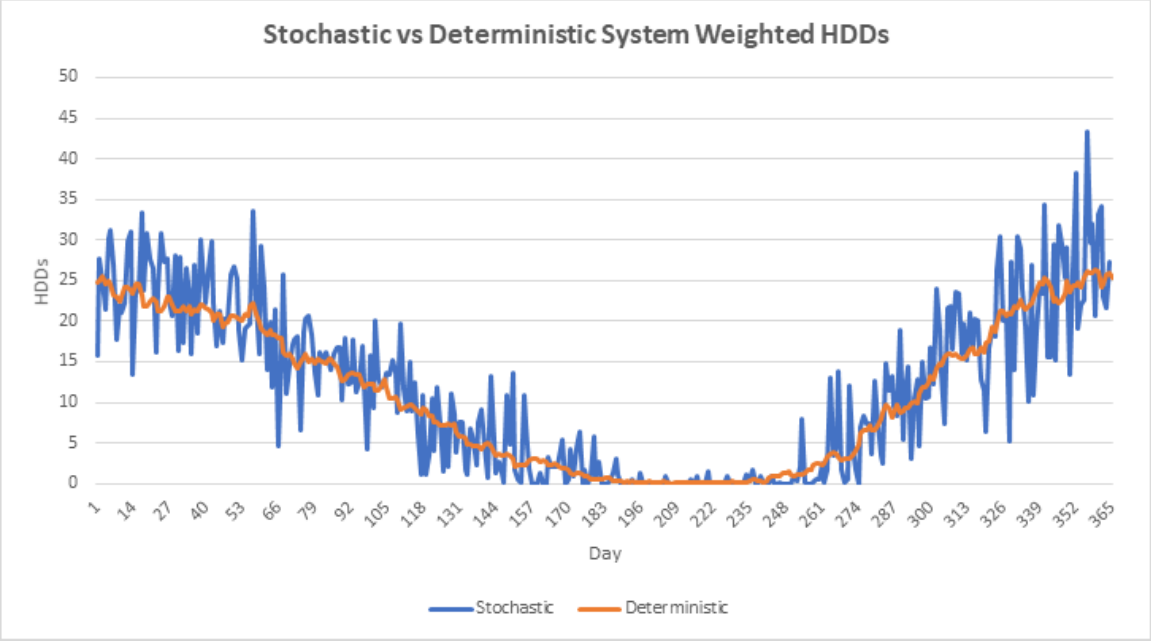


Figure 10-23: Stochastic Vs. Deterministic System Weighted HDDs



Stochastic Analyses – Price Uncertainty

Similar to weather analysis, uncertainty related to future gas prices can have a significant impact on Cascade's forecasted costs over the 20-year planning horizon. The Company analyzes the risk of price projections by running the 95th percentile of monthly load weighted prices with a variety of carbon and environmental externality costs as its sensitivity analyses. The 95th percentile can be viewed as a value in which all potential values fall beneath it 95% of the time. Figure 10-24 provides a potentially extreme price forecast, especially the 95th percentile of possible pricing, for each basin. Figure 10-25 compares these stochastic forecasts to their deterministic counterparts as a visual representation of the impact of a one-in-twenty price movement, also known as a black swan event, on the regional pricing paradigm. All of these prices include the cost of carbon compliance at the SCC with a two and one-half percent discount rate.

Figure 10-24: 95th Percentile Price Forecast by Basin – Monte Carlo Data

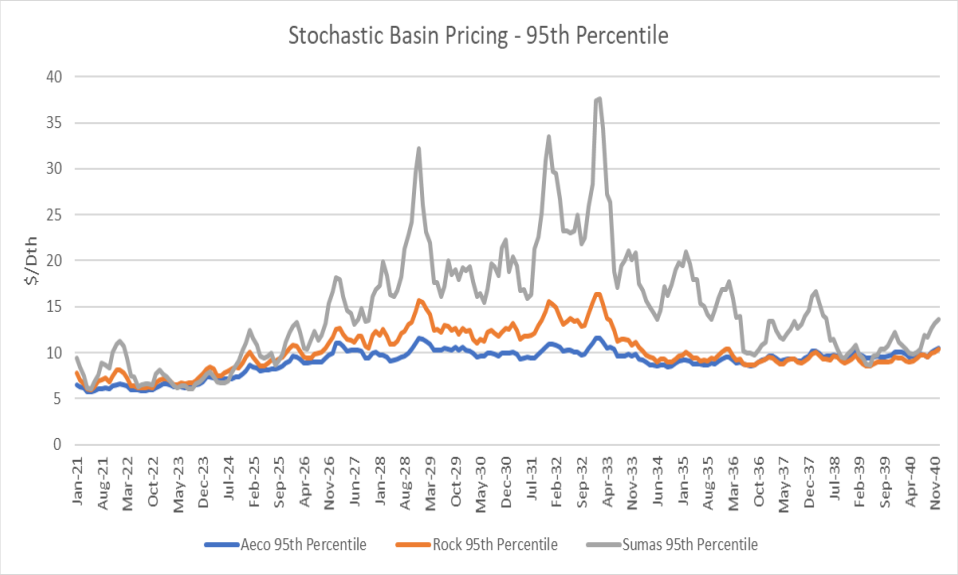
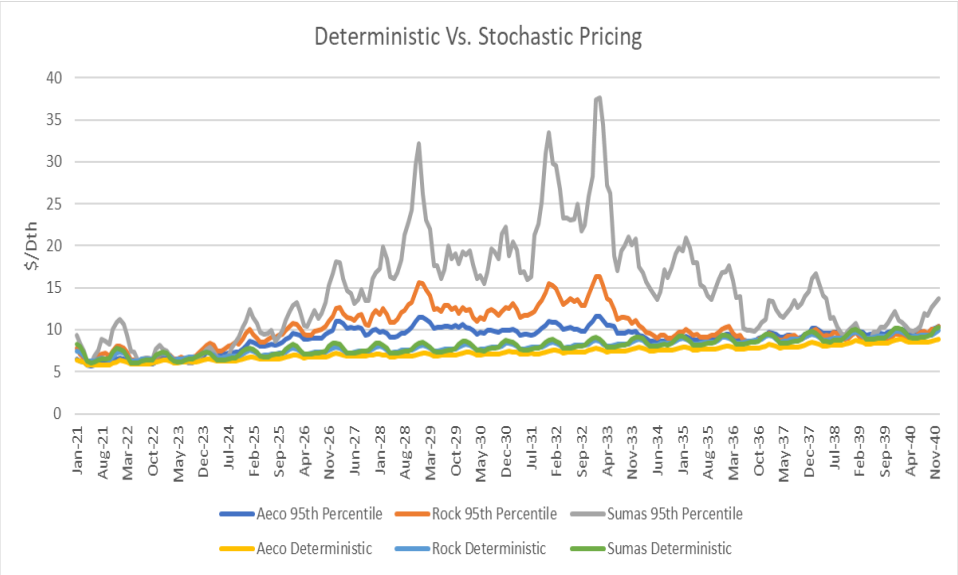


Figure 10-25: Deterministic Vs. Stochastic Pricing



It is important to note that the forecasted spikes in Sumas pricing do not correlate to a projection of any specific event. Sumas has shown historically to have the highest variance among the three basins Cascade can purchase gas from, and this variance can lead to extreme pricing when one is modeling black swan pricing, which is the case at the 95th percentile.

Conclusion

Cascade's All-In portfolio includes all existing supply side resources as discussed in Chapter 4, all projected DSM savings discussed in Chapter 7, and all incremental resources discussed in this chapter. The All-In portfolio did not exceed the VaR Limit in any traditional scenarios or sensitivities run by the Company. This allows Cascade to deem this to be the Preferred Portfolio, which is the lowest cost and risk as expected when considering all alternate supply and demand side resources. This is primarily due to Cascade's geographical spread across the region. The Company's existing long-term transportation contracts, coupled with robust supply basins, provide a base foundation to meet the load needs of Cascade's core customers. However, Cascade's unique geographical reach also creates particular challenges as the system is non-contiguous, often requiring the Company to hold transportation capacity on multiple upstream pipelines to feed the single upstream pipeline that is connected to a particular citygate.

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

Chapter 11

Stakeholder Engagement

Overview

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

Key Points

- Five TAG meetings were held. Due to the COVID-19 pandemic, all TAG meetings were held virtually.
- Multiple opportunities for public participation were available, including access to the Company's Resource Planning Team through phone discussions and email.
- TAG meeting agendas and presentations are available at www.cngc.com.

Approach to Meetings and Workshops

Typically, the Company holds a series of public meetings in the state of Washington for the development of this specific IRP. Cascade's IRP stakeholders are widely spread out geographically; cities in western Washington are generally more easily accessible for individuals to attend than Kennewick for TAG meetings. Cascade scheduled five TAG meetings between April and September 2020. Due to travel and social distancing restrictions as a result of the COVID-19 pandemic, these meetings were held virtually using Microsoft Teams. Additionally, Cascade held an upstream emissions workshop following the fifth IRP TAG meeting. Cascade also offered to hold a TAG 6 meeting after the draft IRP had been distributed and comments were returned to Cascade, but it was determined by all stakeholders that a sixth TAG meeting was not required.

In an effort to further clarify roles and responsibilities for the Company as well as stakeholders, Cascade follows a stakeholder engagement document, which can be found in Appendix A. Cascade recognizes that involvement in the Company's TAG represents a material time commitment. The Company appreciates the investment of time attendees provide to this process by reviewing multiple documents and making subsequent suggestions. This IRP has benefited from the focus of the engaged stakeholders.

Stakeholders

The Company encourages public participation in the IRP process. Participants invited to these public meetings include interested customers, regional upstream pipelines, Pacific Northwest Local Distribution Companies, Commission Staff, stakeholder representatives such as the Northwest Gas Association, Public Counsel, Citizens' Utility Board, Washington Department of Ecology, Northwest Energy Coalition, and the Alliance of Western Energy Consumers.

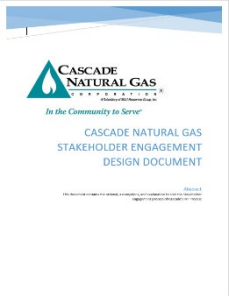
Internally, the Cascade IRP stakeholders and participants are from the following departments:

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

Additionally, Cascade contracted the services of an IRP consultant, Bruce W Folsom Consulting LLC, to assist the Company with meeting the 2020 IRP schedule.

TAG Meetings and Workshops

Cascade held five public TAG meetings with internal and external stakeholders. Due to the COVID-19 pandemic, all meetings were held as virtual with Microsoft Team meetings. Robust discussion occurred, in particular, around energy efficiency, carbon, and renewable natural gas during TAG 4. This meeting is a good example of stakeholder participation and good input to the Company. Information about each meeting date and major agenda items are provided below as well as in Appendix A.



2020 IRP TAG 1 Meeting – Wednesday, April 15, 2020

- Virtual: 9 am to 12 pm
- Process
- Key Points
- IRP Team
- Timeline
- Regional Market Outlook
- Plan for dealing with issues raised in 2018 IRP

2020 IRP TAG 2 Meeting – Wednesday, May 27, 2020

- Virtual: 9 am to 12 pm
- Demand and Customer Forecast and Non-Core Outlook
- Drilling down into segments of demand forecast

2020 IRP TAG 3 Meeting – Wednesday June 24, 2020

- Virtual: 9 am to 12 pm
- Presentation from Ruby Pipeline of Kinder Morgan
- Distribution System Planning

- Planned Scenarios and Sensitivities
- Alternative Resources
- Price Forecast
- Avoided Cost
- Current Supply Resources
- Transport Issues.

2020 IRP TAG 4 Meeting – Thursday, August 13, 2020

- Virtual: 9 am to 1 pm
- Carbon Impacts
- Energy Efficiency (Energy Trust of Oregon)
- Renewable Natural Gas
- Preliminary Resource Integration Results

2020 IRP TAG 5 Meeting – Wednesday, September 23, 2020

- Virtual: 9 am to 12 pm
- Final Integration Results
- Finalization of plan components
- Two-year Action Plan

2020 IRP Upstream Emissions Meeting – Thursday, October 15, 2020

- Virtual: 9 am to 12 pm
- Upstream Emissions Calculation

Opportunity for Public Participation

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

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

Chapter 12

Two-Year Action Plan

2020 Action Plan

The IRP Action Plan demonstrates Cascade's commitment to implementing the Company's Integrated Resource Plan and creating a portfolio of resources with the reasonable least cost mix of energy supply resources and conservation.

Key Points
Cascade's 2020 Action Plan focuses on:
- Supply Side Resources
- Environmental Policy
- Avoided Cost
- Demand Side Management
- Renewable Natural Gas
- Distribution System Planning
- IRP Process

Resource Planning

Cascade recognizes the importance of gathering best practices from other jurisdictional LDCs. To that end, the Company will continue to participate in the IRP process of at least three regional utilities over the course of the next two years with the objective of incorporating aspects that may enhance Cascade's IRP. Cascade will also attempt to get additional stakeholder involvement through convening the IRP TAG meetings in various locations within Cascade's territory, updates to Company website, and/or other means. The Company will also perform cross validation on new methodologies to ensure the accuracy of the new models.

Cascade will also:
- Continue to work with Northwest Pipeline to pursue opportunities to better align Maximum Daily Delivery Obligations (MDDO) contract delivery rights at no incremental costs to customers through the use of segmentation or other proposals.
- Continue to work on developing scenarios to replicate potential supply and transport impacts for pipeline operational flow orders (OFO) and consideration of other strategies to minimize OFO impacts.
- Continue to develop SENDOUT® direct models for gas cost workbooks provided to commissions during PGA filings to better improve the alignment of resources/costs between the PGA and the IRP.
- Develop more scenarios to specifically address potential Canadian supply market changes such as diversion of Station 2 supplies to Liquified Natural Gas facilities and/or Nova Gas Transmission, Limited, and the impact of the Canadian federal fuel charge on the price and potential switching of supply basins utilization/needs of upstream pipeline transportation over time.
- Develop scenarios that consider sensitivities around municipal natural gas bans or other deep decarbonization possibilities in Cascades service territory.
- Add renewable natural gas as a candidate portfolio for the supply resource optimization process.
- Cascade will investigate the cost and feasibility of a potential hydrogen plant as an alternative resource.

Avoided Cost

Work with stakeholders to ensure Cascade is properly quantifying upstream emissions reductions benefits in the Company's avoided cost calculation.

Demand

Cascade will look into making adjustments to a few methodologies on the demand forecast and scenarios. Those adjustments include:

- Adding wind in the stochastic weather analysis.
- Investigate climate change modeling scenarios.
- Develop a new methodology for peak day. Cascade's peak day is currently the coldest day in past 30 years. Beginning with the 2022 IRP, Cascade's current peak day will fall outside of the 30-year range.
- Discuss, for the 2022 IRP, any potential impacts the COVID-19 crisis may have on demand.

Environmental Policy

Cascade will either begin or continue to participate/monitor the following items:

- Engage and provide feedback as part of public discussions surrounding City of Bellingham Climate Actions.
- Continue to identify opportunities to engage with City of Bend on renewable gas or offset opportunities as implementation of Climate Action Plan begins.
- Monitor service areas for potential GHG reduction goal development relating to energy delivery and supply.
- Identify county level climate initiatives and monitor regional discussions on alternative energy delivery.
- Monitor and provide feedback on carbon pricing and policy developments (i.e., carbon tax or cap and trade bills, ballot measures, electrification bills, etc.).
- Monitor and adapt programs and policies to meet federal and state GHG regulations for energy industry.
- Identify impacts of evolving energy code on energy delivery and supply and continue to pursue maximum-efficiency natural gas technologies for inclusion in DSM efforts.
- Continue current emission reduction and monitoring endeavors (i.e., Methane Challenge Program, Renewable Natural Gas studies).
- Model sensitivity analysis regarding upstream emissions.

Demand Side Management (Energy Efficiency)

Long-term program success requires a commitment to support and advance the Company's EE programs. In this context, Cascade notes the following actions it will take, keeping in mind some are driven by legislative requirements and others are part of operating ever-evolving programs.

Adherence to the Washington Clean Buildings Act, HB 1257,[1] is a key proponent of the EEIP two-year action plan. While a variety of the elements of the bill pertain to energy efficiency programs the Company will focus on the following:

- Implementation and completion of Phase 2 of the CPA with a WUTC filing by Summer 2021.
    - This allows for a complete review of measure assumptions, market availability and ramp rates per the Northwest Power and Conservation Council's Seventh Power Plan.
    - It will also include a low-income specific market segment review to better determine energy efficiency potential in the at-needs community.
    - Provide an updated reality check to the goals set for 2021 through Phase 1 of the CPA.
- Revise the Conservation Plan development timeline from annual to biannual beginning in fall of 2021 and meet all requirements associated with the biannual plan development.
- Meet WA Clean Buildings requirements for early adopters (applies to Commercial property owners of 50,000 square feet or more buildings) including baseline data submission and review through ENERGY STAR®'s Portfolio Manager.

In addition, the program will focus on the following areas to increase uptake in alignment with the higher goals set through LoadMAP:

- Evaluate the progress, and potentially expand, the C/I Mid-Stream pilot for tankless water heaters;
- Research both multi-family offerings to target the sector within Cascade's territories for specialized building upgrades and alternative no cost-low cost options to the existing Energy Savings Kits; and
- Continue to leverage partnerships (NEEA and GTI) to incorporate new technologies as they become viable.

And, not to be understated, Calendar Year 2021 will require consistent adaptive management of the programs based on COVID-19 impacts. Some of the elements of this management will include:

- Exploration of assumptions with the CAG to run alternative potential scenarios through LoadMAP;

[1] *See* http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1257-S3.PL.pdf?q=20201020144814

- Efforts to target C/I customers based on their economic impact, closures and renovation opportunities;
- Exploration of efficiency opportunities associated with improvements to air quality in buildings; and
- Implementation of remote quality inspection processes to initially replace in-person inspections, and eventually transition to a complementary offering with potential to offer light audit review to customers prior to measure installs.

Renewable Natural Gas

While actively participating in RNG policy and rules development in Washington and Oregon, Cascade has created an RNG Project Cost Effectiveness Evaluation Methodology as shown on page 8-8. Due to uncertainty around environmental attributes, as well as other rules and guidelines for RNG, Cascade will continue to develop and update the cost-effective evaluation tool. In addition, the following Action Items will be pursued:

- Continue to hold discussions with potential RNG partners.
- Develop necessary internal protocols to offer RNG services to customers.
- Develop a voluntary RNG program under RCW 80.28.390.

Distribution System Planning

The Company will address the following Action Items for Distribution System Planning.

- Implement various stages or review of the of the list of projects that require an increase in capacity as shown in Appendix I.
- Construct citygate upgrades, over the next several years, in Aberdeen, Kennewick, and Longview.
- Focus on projects to include pipe upgrades as well as increased pipe capacity, while continuing to maintain compliance with Maximum Allowable Operation Pressure regulations.

Figure 12-1 on the following page highlights specific activities of the 2020 Action Plan.

Figure 12-1: Highlights of 2020 Action Plan

Functional Area	Anticipated Action	Timing
Resource Planning	Cascade will: • Attend other regional LDC IRP meetings; • Work with NWP on realigning MDDOs; • Develop modeling scenarios that represent pipeline OFOs; • Improve the alignment of resource/costs between the PGA and the IRP; • Develop more scenarios that address changing Canadian Markets; • Develop scenarios that consider sensitivities around municipal natural gas bans or other deep decarbonization possibilities in Cascades service territory; • Add RNG as a candidate portfolio; and • Investigate the cost and feasibility of a potential hydrogen plant as an alternative resource.	Ongoing, for inclusion in 2022 IRP.
Avoided Cost	Cascade will: • Model sensitivity analysis regarding upstream emissions.	Ongoing, for inclusion in 2022 IRP.
Demand	Cascade will: • Add wind in the stochastic weather analysis; • Investigate climate change modeling scenarios; and • Develop, in collaboration with Staff and stakeholders, a new methodology for peak day. • Discuss, for the 2022 IRP, any potential impacts the COVID-19 crisis may have on demand.	Ongoing, for inclusion in 2022 IRP.
Environmental Policy	The Company will execute the Environmental Policy action items as described on page 12-3 and 12-4.	Ongoing, for inclusion in 2022 IRP.
DSM (Energy Efficiency)	The Company will execute the Demand Side Management action items as described on page 12-4.	Ongoing, for inclusion in 2022 IRP.
Renewable Natural Gas	Cascade will: • Continue to develop and update the cost-effective evaluation tool. • Continue to hold discussions with potential RNG partners. • Develop necessary internal protocols to offer RNG services to customers. • Develop a voluntary RNG program under RCW 80.28.390.	Ongoing, for inclusion in 2022 IRP.
Distribution System Planning	Cascade will: • Implement various stages or review of the of the list of projects that require an increase in capacity as shown in Appendix I. • Construct citygate upgrades, over the next several years, in Aberdeen, Kennewick, and Longview. • Focus on projects to include pipe upgrades as well as increased pipe capacity, while continuing to maintain compliance with Maximum Allowable Operation Pressure regulations.	Ongoing over the next four to five years.

Chapter 13

Glossary and Maps

Glossary of Definitions and Acronyms

The glossary is provided to allow the reader to maintain a location of definitions and acronyms for the content provided in this Integrated Resource Plan. Definitions and Acronyms can be found on pages 13-2 through 13-16. Cascade's citygates and the zone and pipeline each gate is associated with are listed on pages 13-17 through 13-19. Pipeline maps of gas systems that Cascade utilizes are provided on pages 13-20 through 13-33.

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

ACEEE
American Council for an Energy-Efficient Economy.

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

AECO INDEX
Alberta Canada natural gas trading price.

AKAIKE INFORMATION CRITERION (AIC)
A measure of the relative quality of statistical models for a given set of data. Given a collection of models for the data, AIC estimates the quality of each model, relative to each of the other models. Hence, AIC provides a means for model selection.

ANNUAL FUEL UTILIZATION EFFICIENCY (AFUE)
Thermal efficiency measure of combustion equipment like furnaces, boilers, and water heaters.

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

ARIMA MODELING
Autoregressive integrated moving average. A time series analysis technique employed by Cascade in its demand and customer forecast.

ASSET MANAGEMENT AGREEMENT (AMA)
An arrangement that an LDC may enter into with a marketing company to assist with transportation and storage assistance.

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

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

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

BIO NATURAL GAS (BNG)
Typically refers to a gas produced by the biological breakdown of organic matter in the absence of oxygen.

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

CANADIAN ENERGY REGULATOR (CER)
The Canadian equivalent to the Federal Energy Regulatory Commission (FERC). The CER replaced the National Energy Board (NEB) on August 14, 2019.

CHOLESKY DECOMPOSITION
A positive-definite covariance matrix. This matrix is used to draw or sample random vectors from the N-dimensional multivariate normal distribution that follow a desired distribution. This allows for correlations between weather zones to be included when drawing or sampling data distributions for Monte Carlo runs.

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

CITYGATE LOOP
Two or more citygates that transfer natural gas from the interstate pipeline to the same distribution system. Citygates are combined into a loop for modeling purposes because it is difficult to distinguish which citygate feeds a certain distribution system.

CLEAN AIR RULE (CAR)
Greenhouse gas emissions standards codified in WAC 173-442. Invalidated Dec. 15, 2017.

COEFFICIENT OF PERFORMANCE (COP)
The coefficient of performance or COP of a heat pump, refrigerator or air conditioning system is a ratio of useful heating or cooling provided to work required. Higher COPs equate to lower operating costs.

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

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

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

CONSUMER PRICE INDEX (CPI)
As calculated and published by the U.S. Department of Labor, Bureau of Labor Statistics.

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

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

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

CUSTOMER CARE & BILLING (CC&B)
Internal billing data system for Cascade Natural Gas.

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

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

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

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

ELECTRONIC BULLETIN BOARD (EBB)
Online communication systems where one can share, request, or discuss information on just about any subject.

ENERGY INFORMATION ADMINISTRATION (EIA)
The U.S. Energy Information Administration (EIA) is a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. EIA programs cover data on coal, petroleum, natural gas, electric, renewable and nuclear energy. EIA is part of the U.S. Department of Energy.

ENTITLEMENTS
Flow management tool used by upstream pipelines, in conjunction with operational flow orders.

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

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

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

FIRST OF THE MONTH PRICE (FOM)
Supply contracts entered into on a short-term basis to cover expected demand for that month.

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

FOURIER TERMS
An alternative to using seasonal dummy variables, especially for long seasonal periods, is to use Fourier terms. Fourier terms consist of a series of sine and cosine terms of frequencies that can approximate any periodic function. These terms can be used for seasonal patterns with great advantage over seasonal dummy variables.

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

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

GAS MANAGEMENT SYSTEM (GMS)
A transactional and reporting system to consolidate natural gas nominations, contracts, balancing and pricing data.

GAS SUPPLY OVERSIGHT COMMITTEE (GSOC)
Oversees the Company's gas supply purchasing and hedging strategy. Members of GSOC include Company senior management from Gas Supply, Regulatory, Accounting & Finance, Engineering, and Operations.

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

GAUSSIAN (NORMAL) DISTRIBUTION
A distribution of many random variables that form a symmetrical bell-shaped graph.

GEOMETRIC BROWNIAN MOTION (GBM)
A continuous-time stochastic process in which the log of the randomly varying quantity follows a random shock combined with a drift element.

GREENHOUSE GAS (GHG)
A greenhouse gas is a gas that absorbs and emits radiant energy within the thermal infrared range. Increasing greenhouse gas emissions cause the greenhouse effect. The primary greenhouse gases in Earth's atmosphere are water vapor, carbon dioxide, methane, nitrous oxide and ozone.

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

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

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

INTEGRATED RESOURCE PLAN (IRP)
The document that explains Cascade's long-range plans and preparations to maintain sufficient resources to meet customer needs at a reasonable price.

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

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

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

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

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

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

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

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

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

LOADMAP
Microsoft Excel-based modeling tool developed by AEG to determine the Technical/Economic/Achievable Potential savings of various proposed DSM programs

LOCAL DISTRIBUTION COMPANY (LDC)
LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area.

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

LOWEST REASONABLE COST (LRC)
LRC methodology is used when evaluating alternatives to determine the optimal solution to a given problem.

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

MDDO
Maximum daily delivery obligation.

MDQ
Maximum daily quantity.

MDT
Thousands of dekatherms.

MEMORANDUM OF UNDERSTANDING (MOU)
A memorandum of understanding (MOU) is a nonbinding agreement between two or more parties outlining the terms and details of an understanding, including each parties' requirements and responsibilities. An MOU is often the first stage in the formation of a formal contract.

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

NATIONAL ENVIRONMENTAL POLICY ACT (NEPA)
A United States environmental law that promotes the enhancement of the environment and established the President's Council on Environmental Quality (CEQ). The law was enacted on January 1, 1970.

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

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

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

NGV
Natural gas vehicles.

NOMINAL
Discounting method that does not adjust for inflation.

NOMINATION
The scheduling of daily natural gas requirements.

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

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

NORTH AMERICAN ENERGY STANDARDS BOARD (NAESB)
Serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

NORTHWEST BUILDER OPTION PACKAGES (NWBOP)
A prescriptive method for labeling new homes as ENERGY STAR. BOPs specify levels and limitations for the thermal envelope (insulation and windows), HVAC and water heating equipment efficiencies for the Pacific Northwest. BOPs require a third-party verification, including testing the leakage of the envelope and duct system, to ensure the requirements have been met.

NORTHWEST GAS ASSOCIATION (NWGA)
A trade organization of the Pacific Northwest natural gas industry. The NWGA's members include six natural gas utilities serving communities throughout Idaho, Oregon, Washington and British Columbia; and three natural gas transmission pipelines that transport natural gas from supply basins into and through the region.

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

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

NOVA GAS TRANSMISSION (NOVA or NGTL)
See TransCanada Alberta System.

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

OPAL (OPAL HUB)
Natural gas trading hub in Lincoln County, Wyoming.

OPERATIONAL FLOW ORDER (OFO)
A mechanism to protect the operational integrity of the pipeline. Upstream pipelines may issue and implement System-Wide or Customer-Specific OFOs in the event of high or low pipeline inventory. OFOs require shippers to take action to balance their supply with their customers' usage on a daily basis within a specified tolerance band. Shippers may deliver additional supply or limit supply delivered to match usage. Violations or failure to comply with an OFO can result in the pipeline assessing penalties to offending shippers.

OREGON PUBLIC UTILITY COMMISSION (OPUC)
The chief electric, gas and telephone utility regulatory agency of the government of the U.S. state of Oregon. It sets rates and establishes rules of operation for the state's investor-owned utility companies. The OPUC's official name is Public Utility Commission of Oregon.

PACIFIC CONNECTOR GAS PIPELINE PROJECT (PCGP)
A proposed 232-mile, 36-inch diameter pipeline designed to transport up to 1 billion cubic feet of natural gas per day from interconnects near Malin, Oregon, to the Jordan Cove LNG terminal in Coos Bay, Oregon, where the natural gas will be liquefied for transport to international markets

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

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

PERFORMANCE TESTED COMFORT SYSTEMS (PTCS)
Northwest regional programs with a focus on improving HVAC system comfort and increasing savings. They promote contractor training for properly sealing ducts and installing high-efficiency heat pumps, with a focus on sizing, commissioning, and setting controls. Technicians must complete a BPA-approved training to be certified to perform work in this program. These programs are supported by BPA and Northwest Public Utilities.

POUNDS PER SQUARE INCH (PSI)
The standard unit of measure when determining how much pressure is being applied when gas is flowing through a pipe.

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

PRESENT VALUE OF REVENUE REQUIREMENT (PVRR)
The annual revenues required by the firm to cover both its expenses and have the opportunity to earn a fair rate of return. The annual costs to provide safe and reliable service to the company's customers that the company is allowed to recover through rates. The present value a future sum of money or stream of cash flows given a specified rate of return. Future cash flows are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows.

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

R
A programming language and free software environment for statistical computing and graphics supported by the R Foundation for Statistical Computing.

REAL
Discounting method that adjusts for inflation.

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

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

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

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

RENEWABLE FUEL
A power source that is continuously or cyclically renewed by nature, i.e. solar, wind, hydroelectric, geothermal, biomass, or similar sources of energy.

ROCKIES INDEX
Natural gas trading price near the Rocky Mountains.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TOTAL RESOURCE COST (TRC)
Measures the net costs of a demand side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The test is applicable to conservation, load management, and fuel substitution programs.

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

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

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

TRANSPORTATION SERVICE AGREEMENT (TSA)
A transportation services agreement is a contract made between goods providers and those who offer transportation for those goods. In the context of the IRP, this refers to shippers and upstream pipelines.

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

UPSTREAM PIPELINE CAPACITY
The pipeline delivering natural gas to another pipeline at an interconnection point where the second pipeline is closer to the consumer. In the context of the IRP this refers to any transmission pipeline that is upstream of the Cascade distribution system.

VALUE AT RISK (VaR)
A metric used to quantify uncertainty into a tangible number.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION (WUTC)
A three-member commission appointed by the governor and confirmed by the state senate. The Commission's mission is to protect the people of Washington by ensuring that investor-owned utility and transportation services are safe, available, reliable and fairly priced.

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

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

WOODS & POOLE (W&P)
An independent firm that specializes in long-term county economic and demographic projections.

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

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

DESCRIPTION	METER	ZONEID	PIPELINE
7TH DAY ADVENTIST FARM TAP	ADVENSCH	ZONE 10	NWP
A & M RENDERING	AMRENDER	ZONE 30-W	NWP
A & W FEED LOT FARM TAP	AWFEED	ZONE 20	NWP
ABERDEEN/HOQUIAM/MCCLEARY	ABRNDHOQ	ZONE 30-S	NWP
ACME	ACME	ZONE 30-W	NWP
ALCOA, WENATCHEE	ALCOA	ZONE 11	NWP
ARLINGTON	ARLINGTN	ZONE 30-W	NWP
ATHENA/WESTON	ATHENA	ZONE ME-OR	NWP
BAKER	BAKER	ZONE 24	NWP
BELLINGHAM II	BLLINGII	ZONE 30-W	NWP
BELLINGHAM/FERNDALE	BLHAM	ZONE 30-W	NWP
BEND TAP	BEND	ZONE GTN	GTN
BREMERTON (SHELTON)	BREMERTON	ZONE 30-S	NWP
BRULOTTE HOP RANCH	BRULOTTE	ZONE 10	NWP
BURBANK HEIGHTS	BURBANKH	ZONE 20	NWP
CASTLE ROCK	CASTLERK	ZONE 26	NWP
CHEMICAL LIME	CHEMLIME	ZONE 24	NWP
CHEMULT	CHEM	ZONE GTN	GTN
DEHANNS DAIRY FARM TAP	DEHANDRY	ZONE 10	NWP
DEMING	DEMING	ZONE 30-W	NWP
EAST STANWOOD	EAST STANWOOD	ZONE 30-W	NWP
FINLEY	FINLEY	ZONE 20	NWP
GILCHRIST TAP	GILC	ZONE GTN	GTN
GRANDVIEW	GRDVEW	ZONE 10	NWP
GREEN CIRCLE FARM TAP	GRENCIRL	ZONE 26	NWP
HERMISTON	HERMSTON	ZONE ME-OR	NWP
HUNTINGTON	HTINGTON	ZONE 24	NWP
KALAMA FARM TAP	KALAMA	ZONE 26	NWP
KALAMA NO. 2	KALAMA2	ZONE 26	NWP
KAWECKI, WENATCHEE	KAWECKI	ZONE 11	NWP
KENNEWICK	KENEWICK	ZONE 20	NWP
KOMOS FARMS TAP	KOMO	ZONE GTN	GTN
LA PINE TAP	LAPI	ZONE GTN	GTN
LAMBERT'S HORTICULTURE	LAMBERTS	ZONE 10	NWP
LAWRENCE	LAWRENCE	ZONE 30-W	NWP
LDS CHURCH FARM TAP	LDSCHURC	ZONE 30-W	NWP
LONGVIEW-KELSO	LONGVIEW	ZONE 26	NWP
LYNDEN	LYNDEN	ZONE 30-W	NWP
MADRAS TAP	MADR	ZONE GTN	GTN
MENAN STARCH	MEMANSTR	ZONE 20	NWP
MILTON FREEWATER	MILFREE	ZONE ME-OR	NWP
MISSION TAP	MISSION	ZONE ME-OR	NWP
MOSES LAKE	MOS LAKE	ZONE 20	NWP
MOUNT VERNON	MTVERNON	ZONE 30-W	NWP
MOXEE CITY	MOXEE	ZONE 11	NWP
NORTH BEND	NBEND	ZONE GTN	GTN
NORTH PASCO METER STATION	NPASCO	ZONE 20	NWP
NYSSA-ONTARIO	NYSSA	ZONE 24	NWP
OAK HARBOR/STANWOOD	OAKHAR	ZONE 30-W	NWP
OTHELLO	OTHELLO	ZONE 20	NWP
PASCO	PASCO	ZONE 20	NWP

PATERSON	PATERSON	ZONE 26	NWP
PENDLETON	PENDLETN	ZONE ME-OR	NWP
PLYMOUTH	PLYMTH	ZONE 20	NWP
PRINEVILLE TAP	PRVL	ZONE GTN	GTN
PRONGHORN TAP	PRONGHORN	ZONE GTN	GTN
PROSSER	PROSSER	ZONE 10	NWP
QUINCY	QUINCY	ZONE 11	NWP
REDMOND TAP	REDM	ZONE GTN	GTN
RICHLAND	RICHLAND	ZONE 20	NWP
SANDVIK, KENNEWICK	SANDVIK	ZONE 20	NWP
SEDRO/WOOLLEY ET AL.	SEDRO	ZONE 30-W	NWP
SELAH	SELAH	ZONE 11	NWP
SOUTHRIDGE	STHRDG	ZONE 20	NWP
SOUTH BEND	S BEND	ZONE GTN	GTN
SOUTH HERMISTON TAP	SHRM	ZONE GTN	GTN
SOUTH LONGVIEW FIBRE	SOLONG	ZONE 26	NWP
STANFIELD CITY TAP	STTAP	ZONE GTN	GTN
STEARNS TAP	STEA	ZONE GTN	GTN
SUMAS, CITY OF	SUMASC	ZONE 30-W	NWP
SUNNYSIDE	SUNSIDE	ZONE 10	NWP
TOPPENISH ET AL. (ZILLAH)	TOPENISH	ZONE 10	NWP
U & I SUGAR, MOSES LAKE	UI SUGAR	ZONE 20	NWP
UMATILLA	UMATILLA	ZONE ME-WA	NWP
WALLA WALLA	WALLA	ZONE ME-WA	NWP
WALULA	WALULA	ZONE ME-WA	GTN
WENATCHEE	WENATCHE	ZONE 11	NWP
WOODLAND WA	WOODLAND	ZONE 26	NWP
YAKIMA CHIEF FARMS	YAKCHFRM	ZONE 11	NWP
YAKIMA FIRING CENTER	YAKFIRCR	ZONE 11	NWP
YAKIMA/UNION GAP	YAKIMA	ZONE 11	NWP

Maps of System Infrastructure

Figure 13-1: Map – AECO Hub Storage

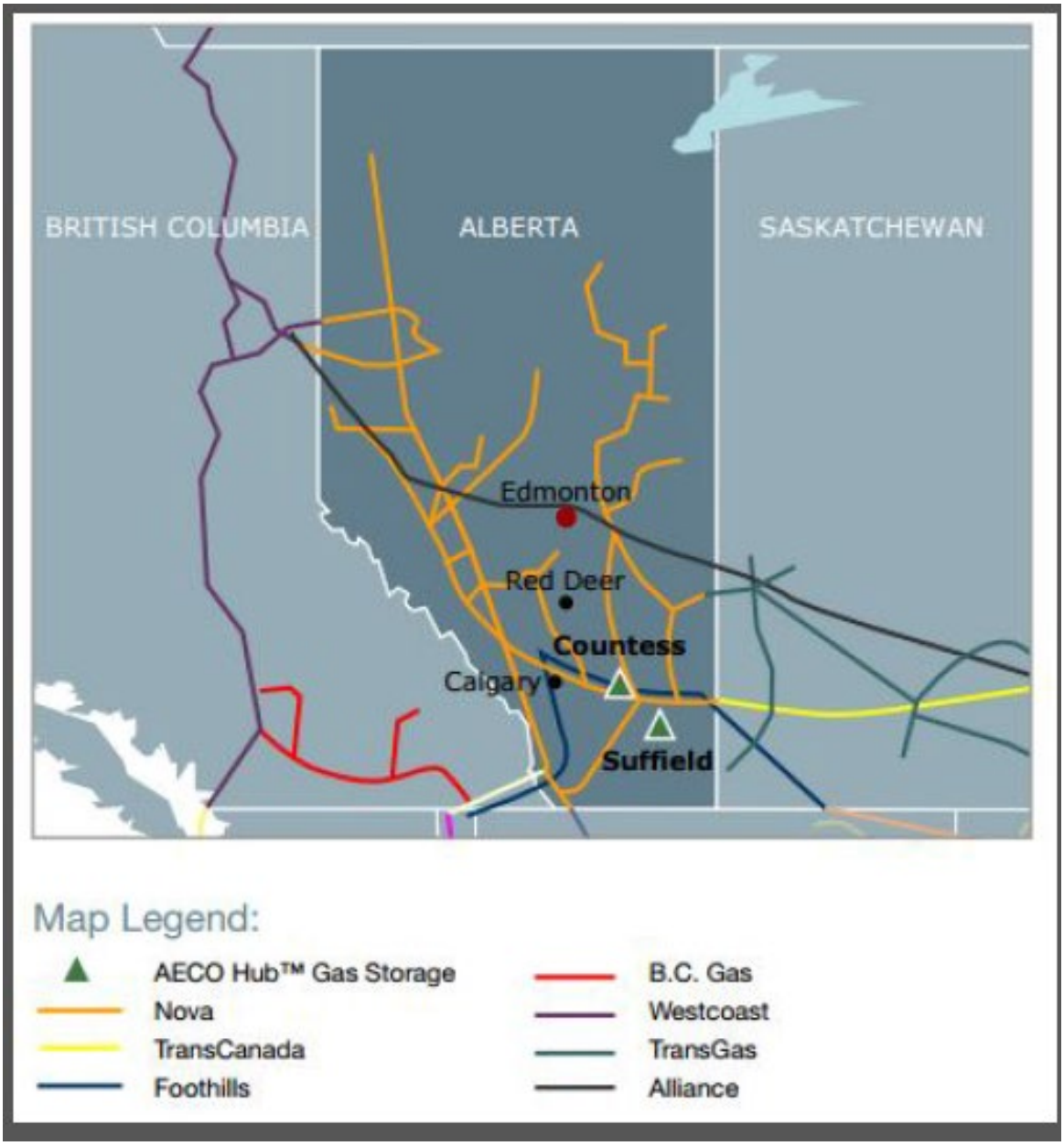


Figure 13-2: Map – California Storage Map

Figure 13-3: Map – Cascade Natural Gas Pipeline System

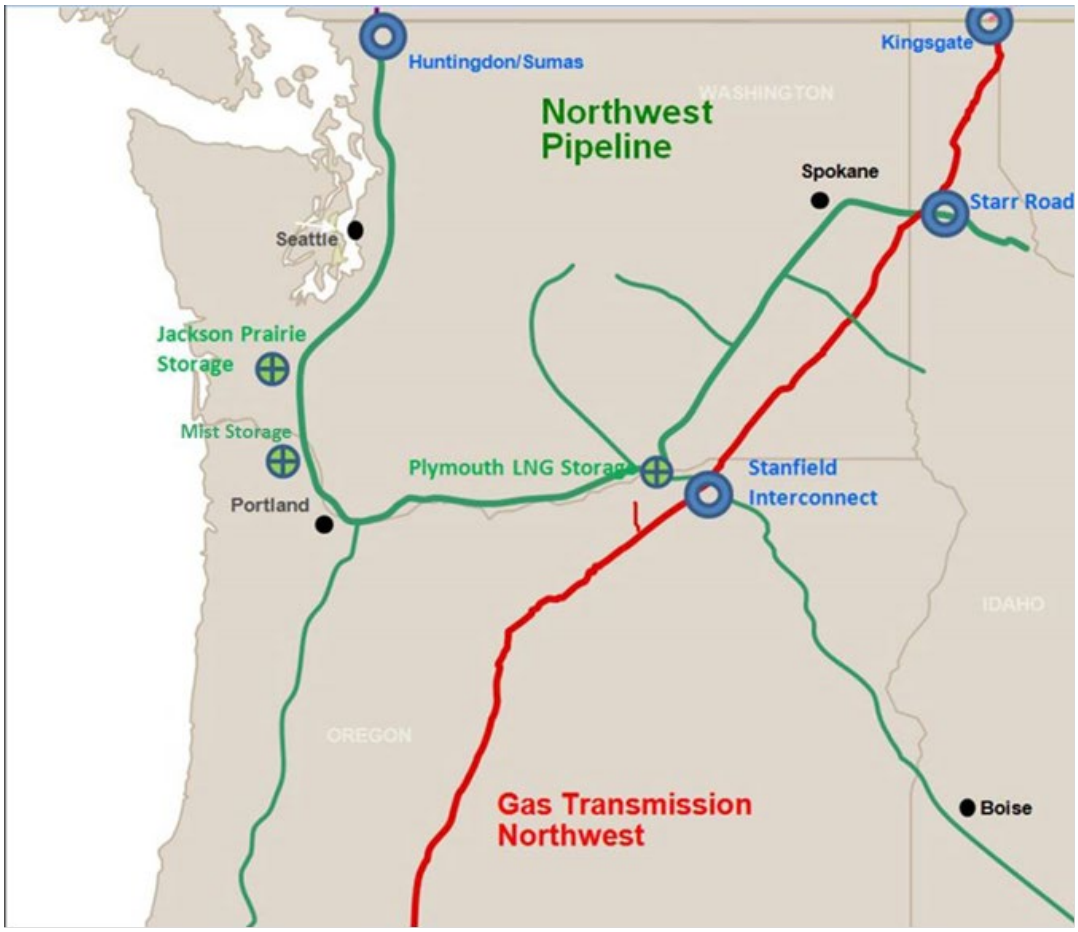


Figure 13-4: Map – Foothills-British Columbia Map

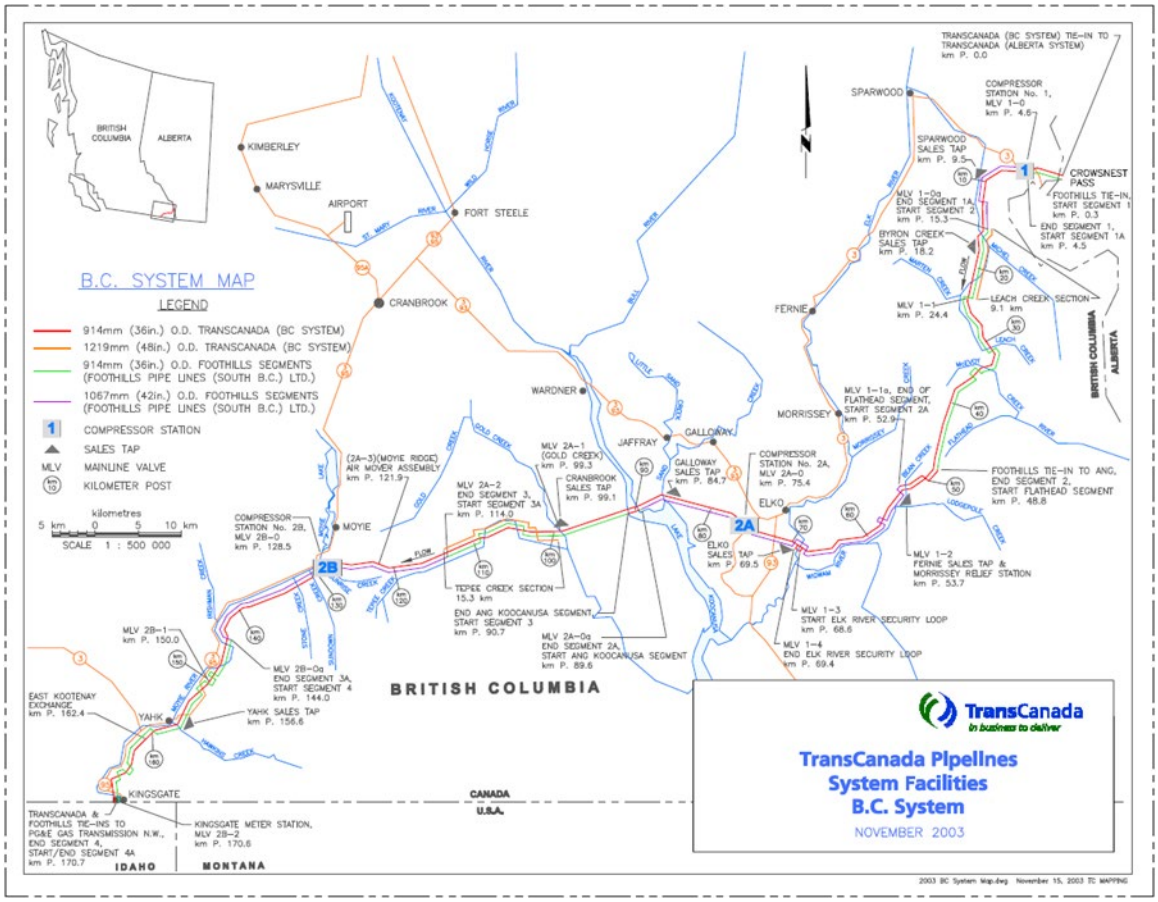


Figure 13-5: Map – Foothills-Full System

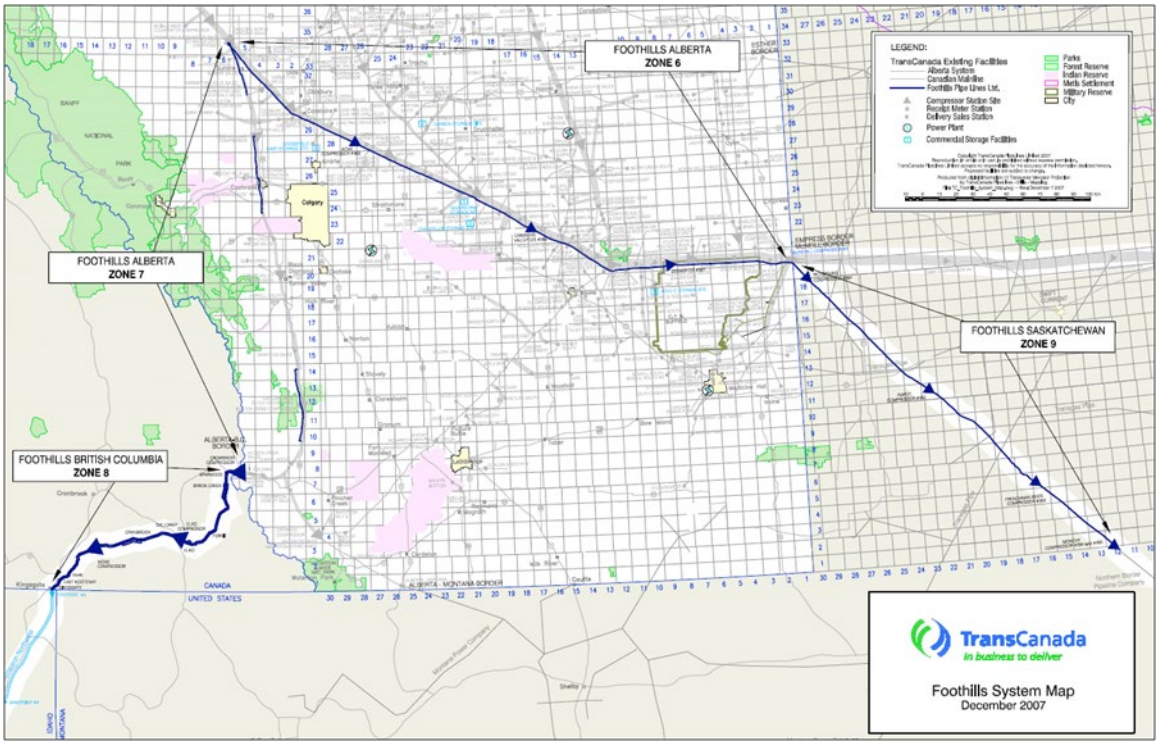


Figure 13-6: Map – GTN System Map

Location	DRN	Mile Post
Kingsgate	3498	0.00
Moyie Springs	196186	22.00
Bonners Ferry	3503	27.04
Schweitzer	159304	55.50
Sandpoint	3496	59.26
Dover Bay	634335	61.14
Sagle Sales	769368	65.22
Athol	160164	84.77
Rathdrum City	3539	97.64
Rathdrum Gen Tap	160138	97.64
Lancaster	314085	99.78
Chase Road Delivery	1389605	102.50
Spokane City	28203	108.29
Spokane Summary	28201	108.29
Mica	28204	121.15
Spangle	28205	134.18
Rosalia	28245	145.71
St. John	28246	158.65
Palouse	217745	172.07
Lacrosse	28247	182.79
Kosmos Farm	159305	271.66
Stanfield	18503	277.37
Stanfield City	18505	282.76
Calpine H.P.P.	314578	282.88
South Hermiston	217744	289.83
CSBRR	196185	304.22
Coyote Springs	196184	304.23
Coyote Springs 2	314579	304.24
Carty	140177	319.50
Carty Generating Station	1401645	319.60
ThreeMile Road Dairy D	21748	319.70
ThreeMile Road Dairy R	21749	319.70
Logan International	217723	304.25
Carty	1401645	324.30
Madras	18430	410.16
Prineville	18432	426.80
Redmond	18402	438.30
Pronghorn Tap	360889	445.80
North Bend	233740	450.28
Bend	18403	454.51
South Bend	217724	457.50
Stearns	18404	469.19
Lapine	159307	483.90
Gilchrist	18437	500.97
Chemult	18440	519.44
Harpold Sales	1402105	599.23
Kingsley Field Tap	473654	599.26
Klamath CoGen	288499	599.27
West Klamath Tap	198183	599.28
Klamath Expansion	311972	599.29
Phoenix Medford	196182	599.30
Turquoise Flats	1049174	609.80
Tuscarora/GTN Interconnect	190094	609.80
Malin	1820	612.46

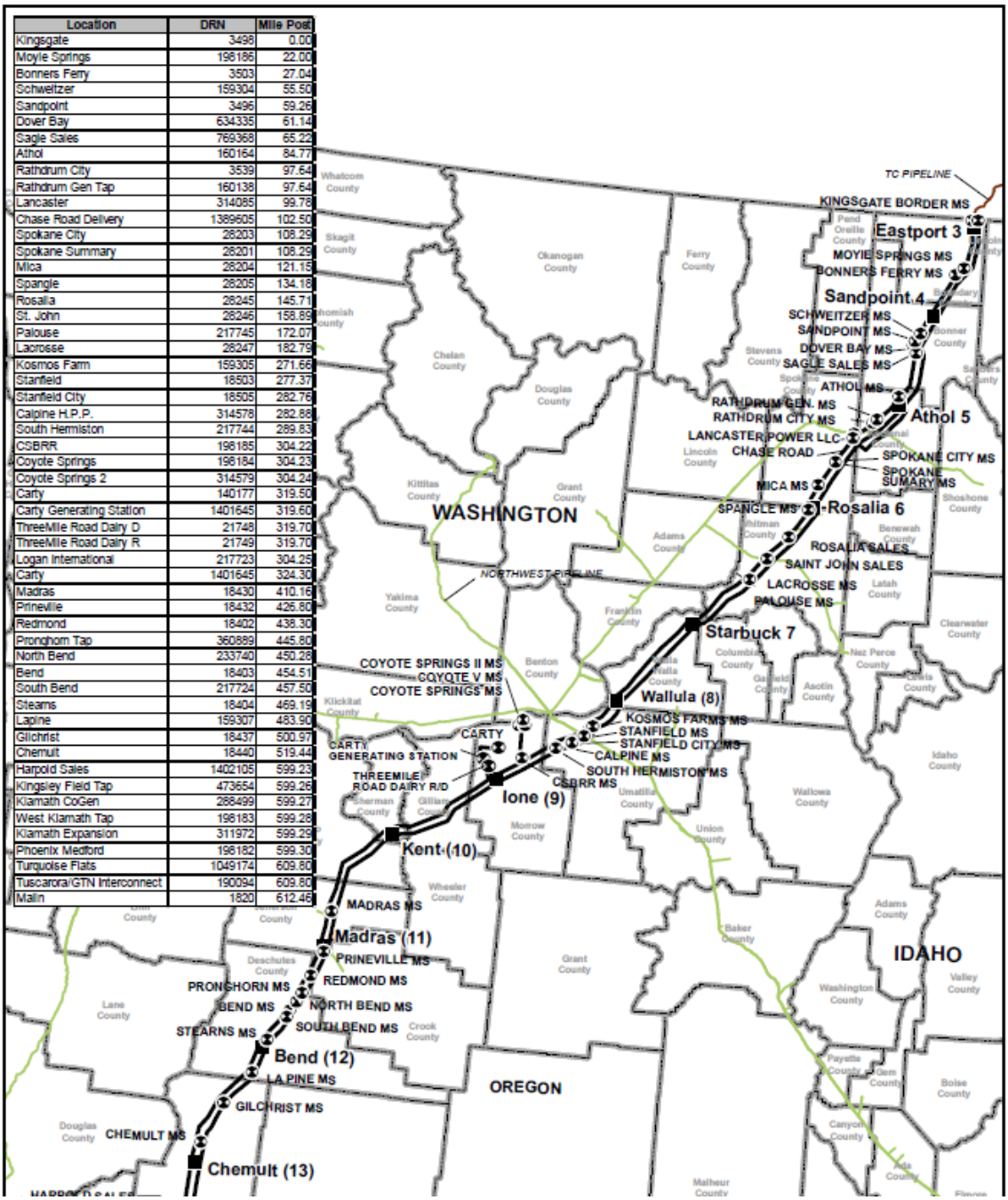


Figure 13-7: Map – NGTL Delivery System Map

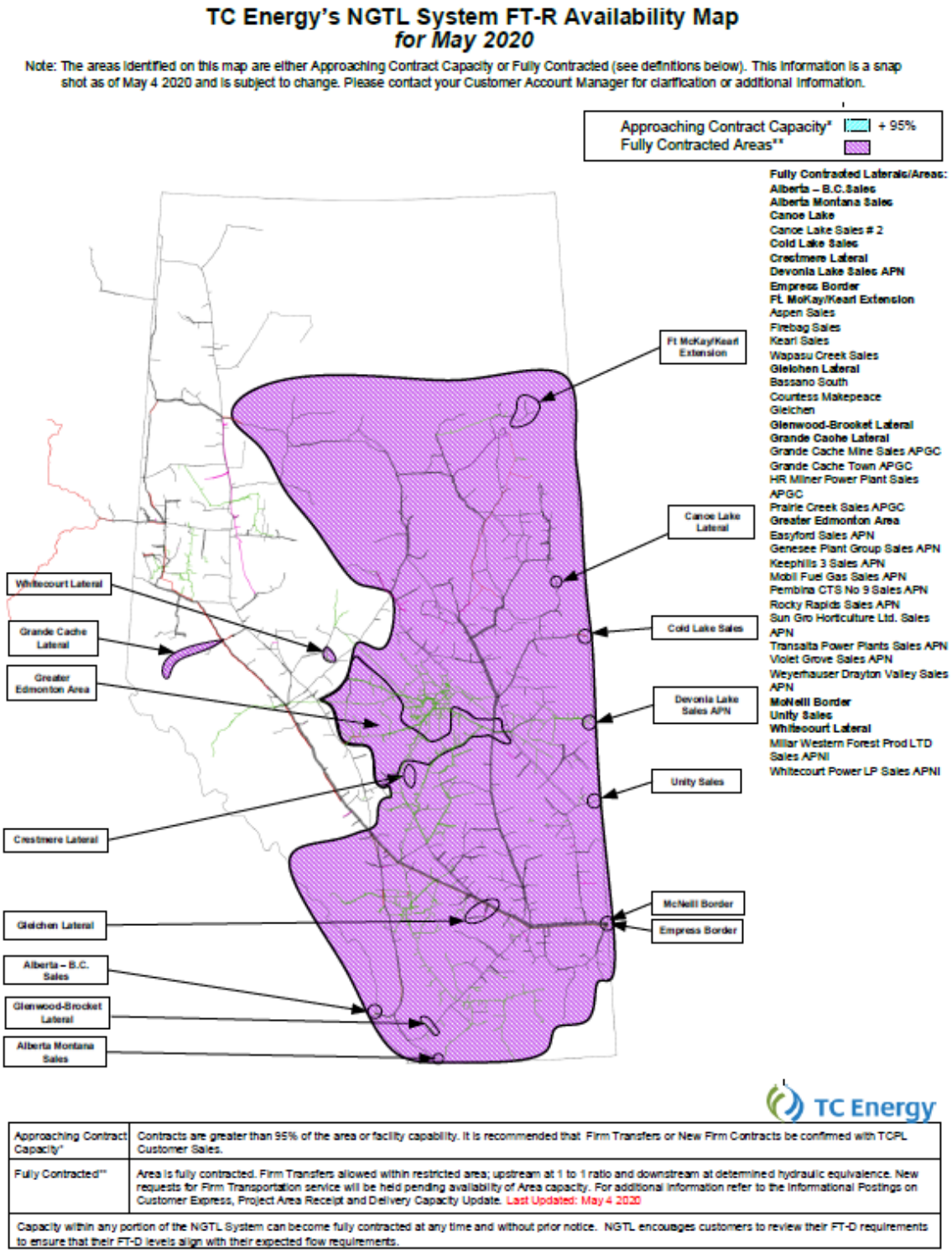


Figure 13-8: Map – NGTL Receipt System Map

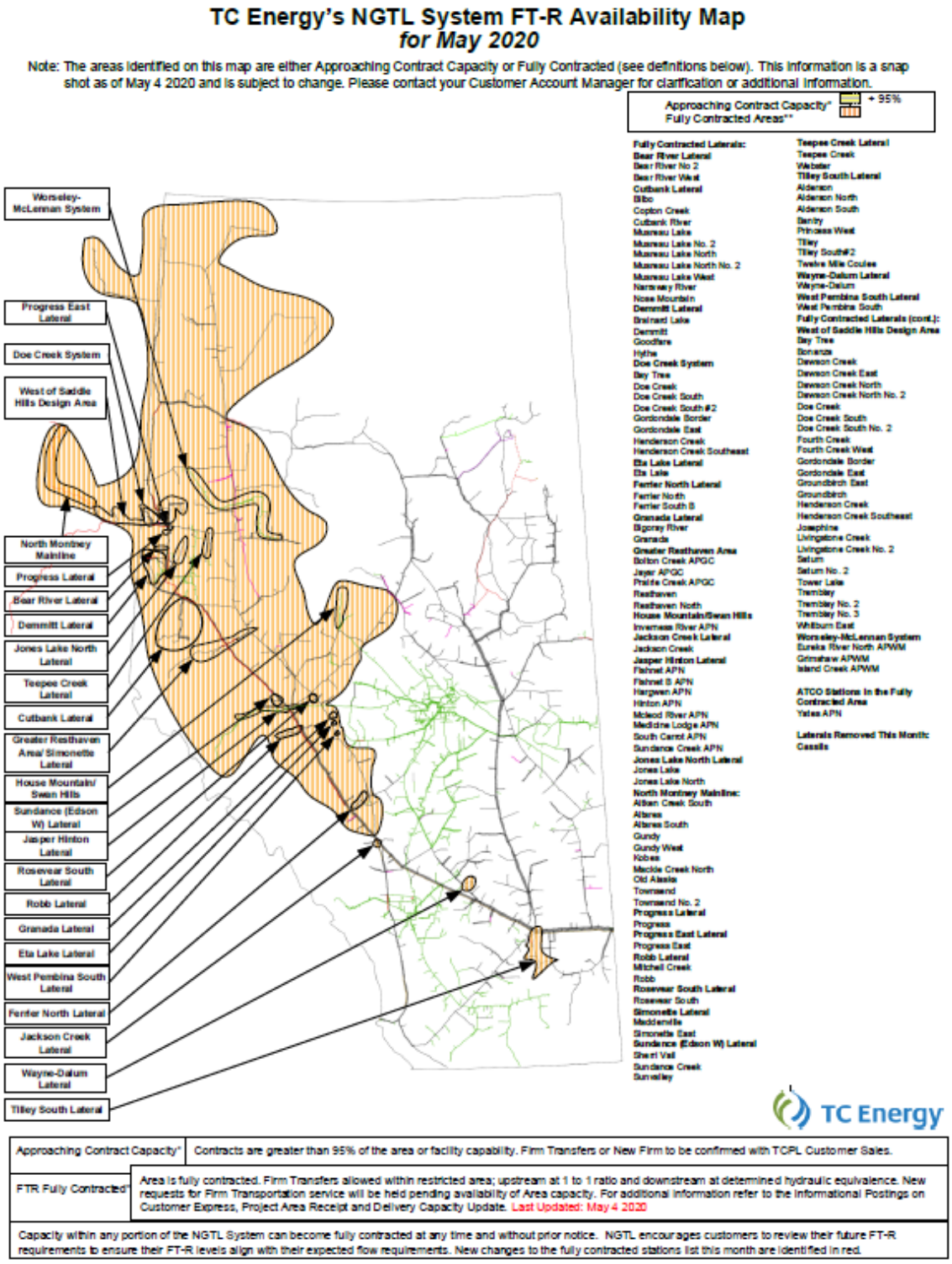


Figure 13-9: Map – NWP North System Map

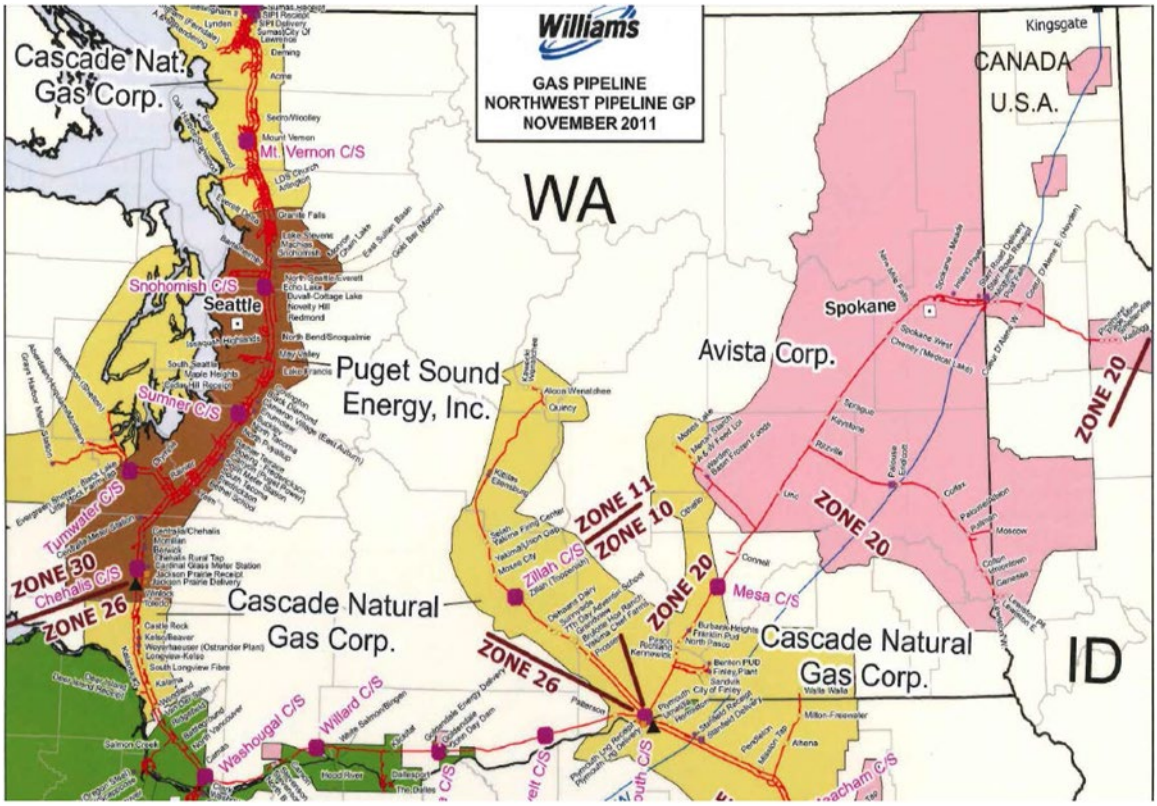


Figure 13-10: Map – NWP South System Map

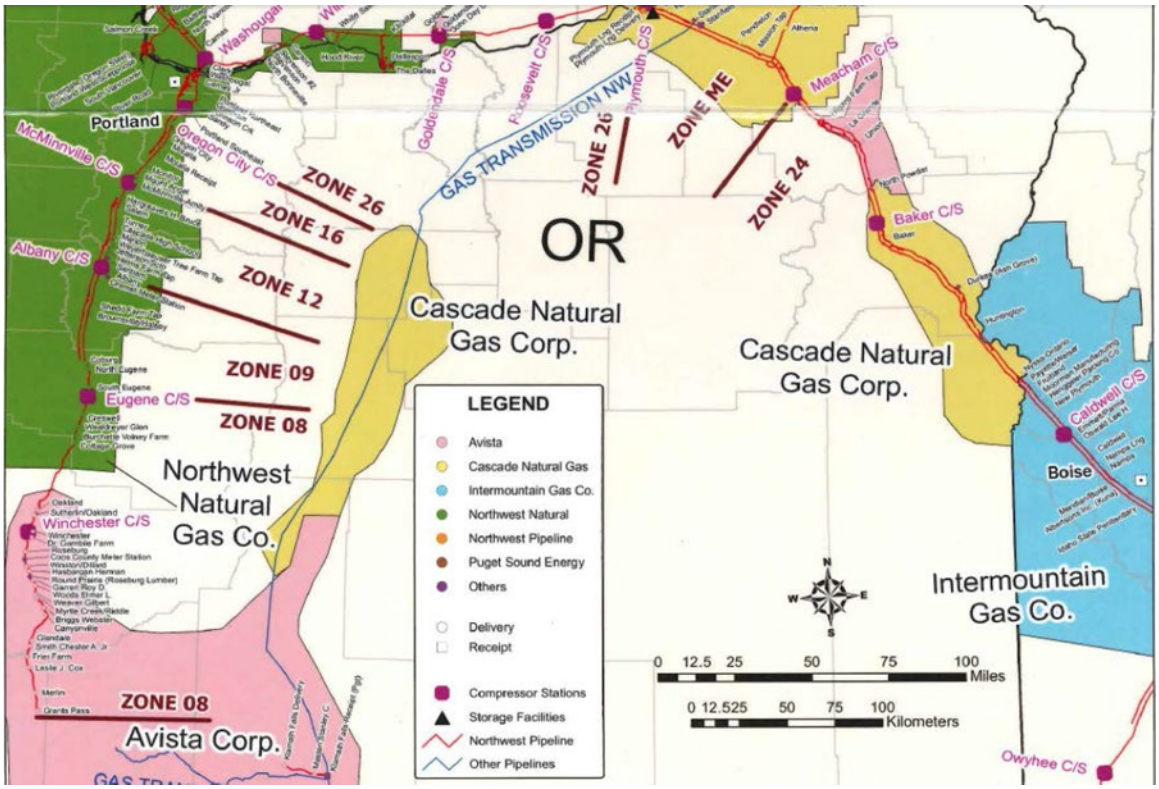


Figure 13-11: Map – Westcoast Sectional Map

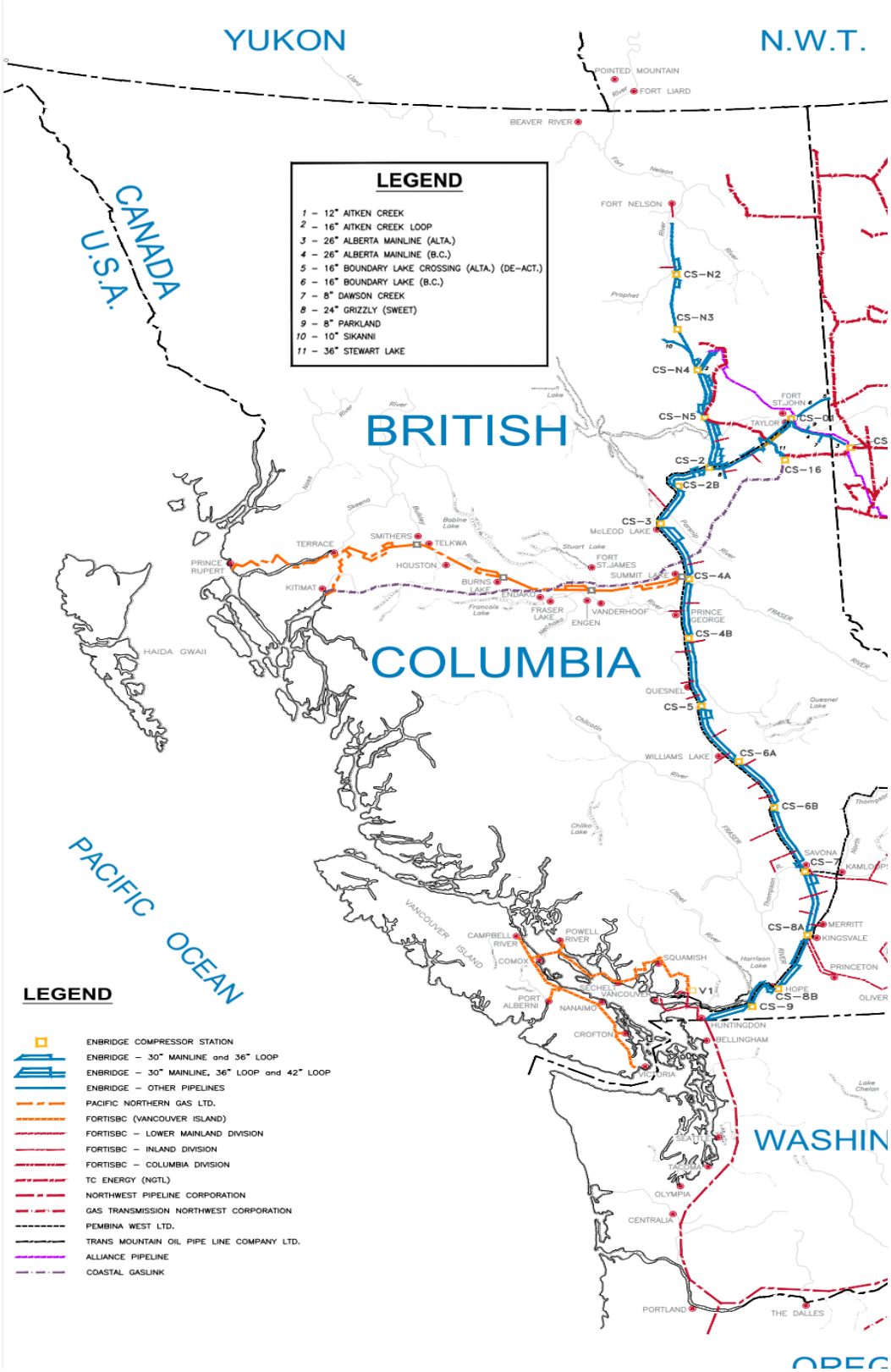


Figure 13-12: Map – Western U.S. and Canadian Pipeline Map

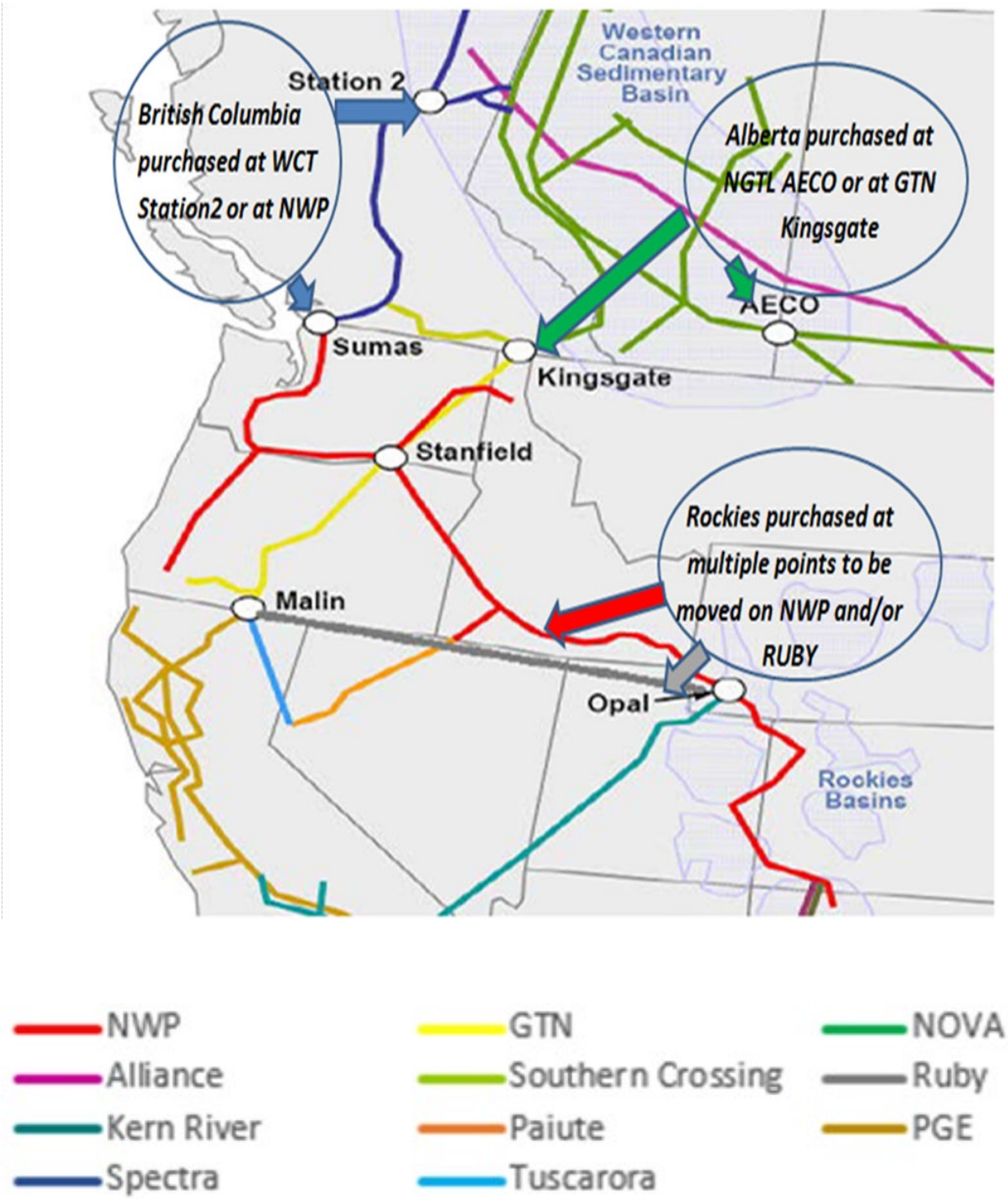


Figure 13-13: Map – Certificated Service Areas as Specified in RCW 80.28.190

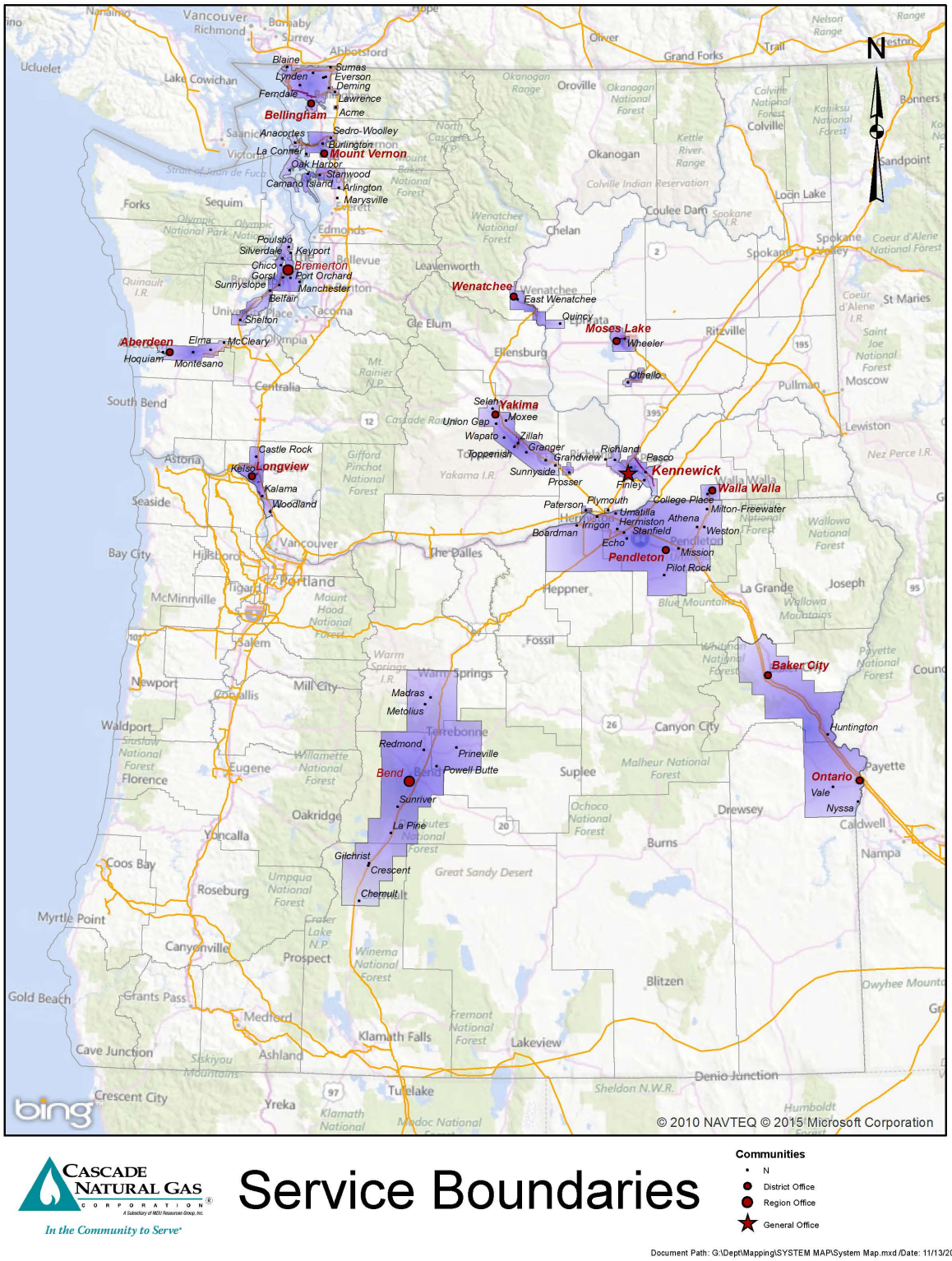


Figure 13-14: Map – Pipeline Transportation Capacity Usage

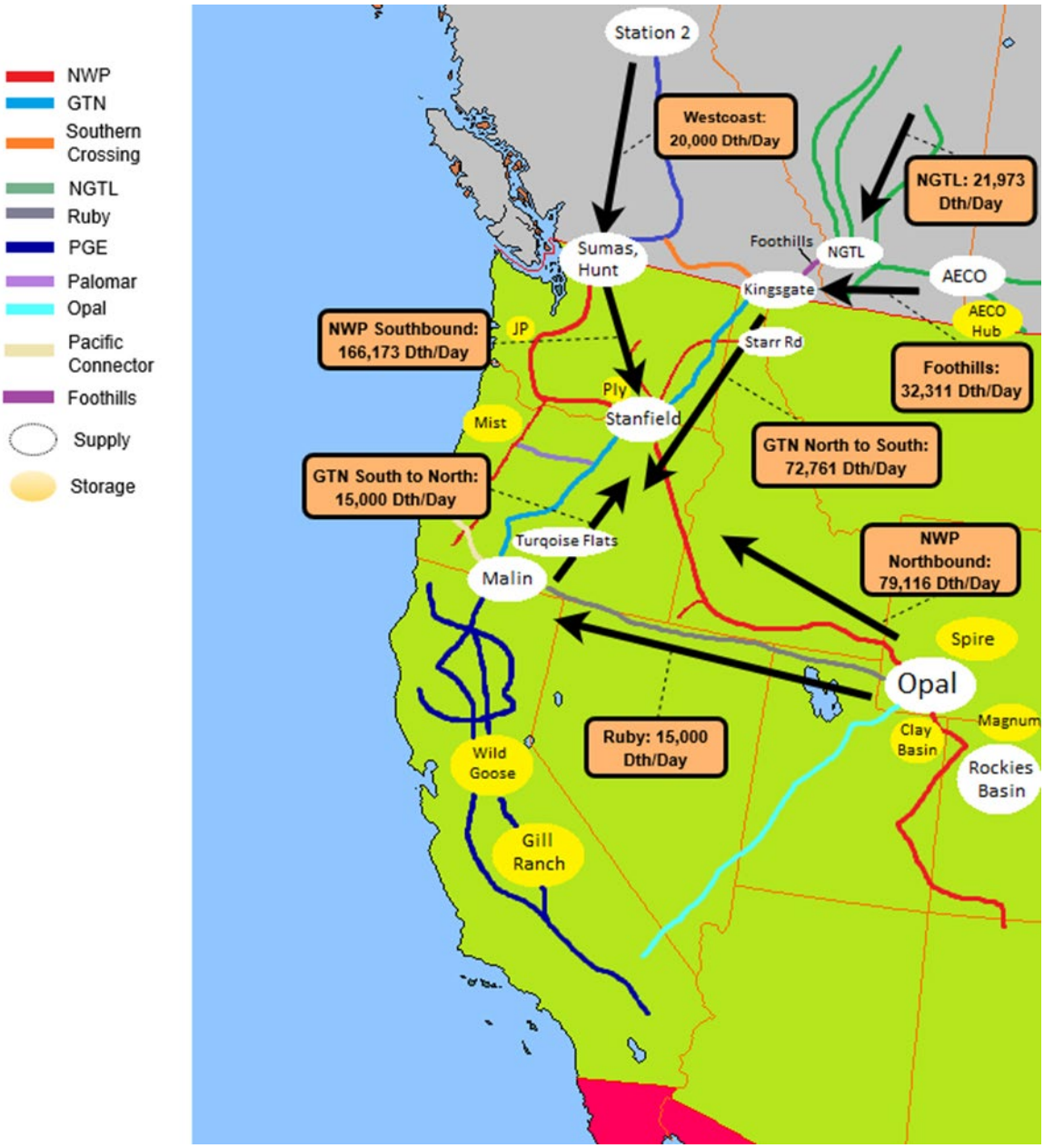
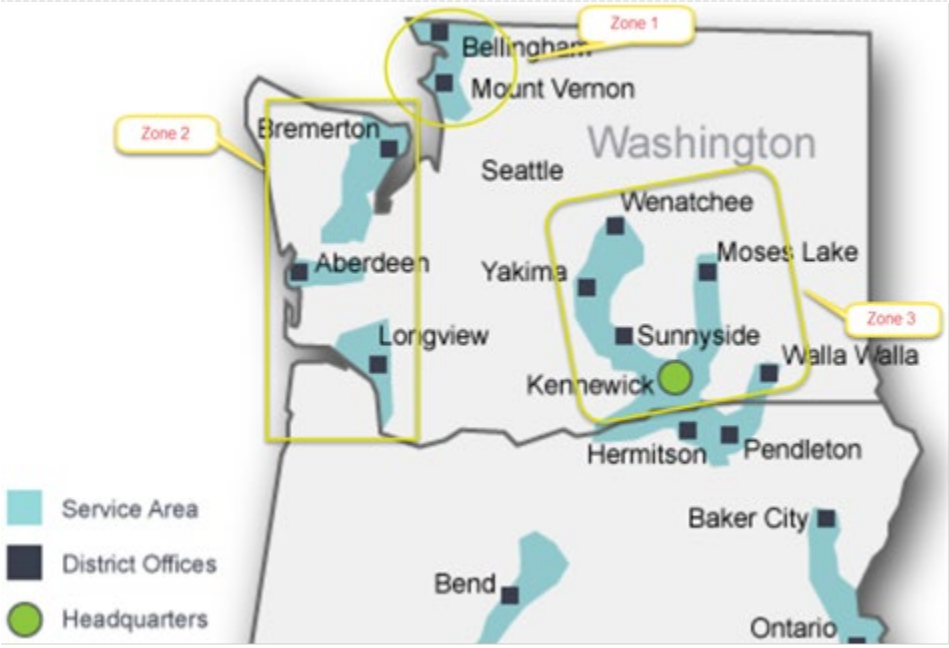


Figure 13-14: Map – Washington Conservation Zones



CITY OF BEND

Community Climate Action Plan

Bend Community Climate Action Plan

Climate Mitigation Strategies and Actions: 2020-2025

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Jacob Riggle, *Web & Graphics Coordinator*
Additional staff who participated in technical working groups

See Appendix H for complete list of other advisory committee and stakeholder participants.

Roadmap to the Community Climate Action Plan

The Bend community has made itself clear – it is time to take action against climate change. Climate change directly impacts Bend residents and the natural environment that makes this area so special. In response to community interest, the City Council adopted Resolution 3044 in September 2016 that established climate action goals to reduce community fossil fuel use by 40% by 2030 and by 70% by 2050.

The Bend community is committed to doing its part to mitigate the most severe impacts of climate change. The Community Climate Action Plan lays out a pathway to reduce our fossil fuel use and demonstrate the will of our community to stand together to protect the environment for generations to come.

The vision for the Community Climate Action Plan is to have neighbors, businesses, and community leaders work together to preserve our natural environment while promoting economic opportunity and resilience for current and future generations.

Terms you should know

This Plan is divided into the four **"climate sectors"** that make up the bulk of Bend's emissions. These are:

- **Energy Supply**
- **Transportation**
- **Energy in Buildings**
- **Waste and Materials**

Within each sector is a list of **"climate strategies"** – higher-level objectives that the community needs to achieve to reduce its fossil fuel use.

Each climate strategy is then broken down into **"climate actions"** – specific policies, programs, or projects that can be implemented to help reach those objectives.

See other terms you don't recognize? Take a look in the glossary on page 40.

How to read the Community Climate Action Plan

Chapters 1-3 provide the context for this Plan by describing the process used to develop it, the impacts of climate change in Bend and how Bend contributes to climate change.

Chapter 4 provides the Vision, Goals, and Guiding Principles for this Plan.

Chapter 5 describes how this Plan proposes to achieve the Vision and Goals.

Chapter 6 details the specific climate strategies and actions the City and the community have developed to help Bend reduce its fossil fuel use and meet its emissions reduction targets.

Chapter 7 describes how the City and community will coordinate to implement and evaluate this Plan going forward.

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1. Background

In 2016, Bend residents made themselves clear – the Bend community wants local, community action to address climate change. Bend is a community that is deeply connected to its natural resources. Situated in beautiful Central Oregon, where the Cascade mountains meet the high desert, abundant natural beauty is one of the reasons residents love to call Bend home. The natural resources surrounding Bend have also long been vital to the Bend economy. From its timber industry roots to its present-day support from the outdoor recreation industry, healthy ecosystems surrounding the community benefit all who live here.

In response to the community's push for local climate action, the Bend City Council set climate action goals **to reduce fossil fuel use community wide by 40% by 2030 and by 70% by 2050.** These goals are documented in Bend City Council Resolution 3044, which states:

"Meaningful action is needed at all levels of government to mitigate and adapt to climate change, protect the public trust, ensure a resilient community, and leave a healthy environment and atmosphere for future generations. The City and community of Bend also recognize that energy conservation and other actions to address climate change can complement economic development and contribute to a thriving and livable community."

The term "fossil fuels" describes energy sources that come from ancient organisms and plant matter. Examples of fossil fuels include coal, oil, and natural gas.

What is the Bend Community Climate Action Plan?

The Bend Community Climate Action Plan is a set of strategies that will guide the City and community as we work together to reduce our fossil fuel usage. The City and the Climate Action Steering Committee have developed this Plan with extensive participation by the Bend community.

The strategies consist of new and expanded programs, policies, and systems that the community proposed and vetted. They are meant to encourage and support residents, businesses and other agencies to reduce the community's fossil fuel use and help mitigate climate change. When the climate resolution was passed, the community and the City decided to focus the Plan on mitigation strategies, which directly reduce the amount of emissions that Bend contributes to the atmosphere, rather than adaptation strategies. The strategies in this Plan are near-term activities that can be initiated or complete in three to five years. The goal is to implement this Plan from 2020 through 2025, and then update this Plan on a regular basis as we continue working towards the 2050 goal.

Every day, we make decisions about what to build, invest in, and buy. The climate impact of those decisions will play a role in what Bend looks like for today's children, their children and beyond. This Plan is a roadmap that will guide our community in making decisions that support a sustainable, healthy future for all.

A Community Effort

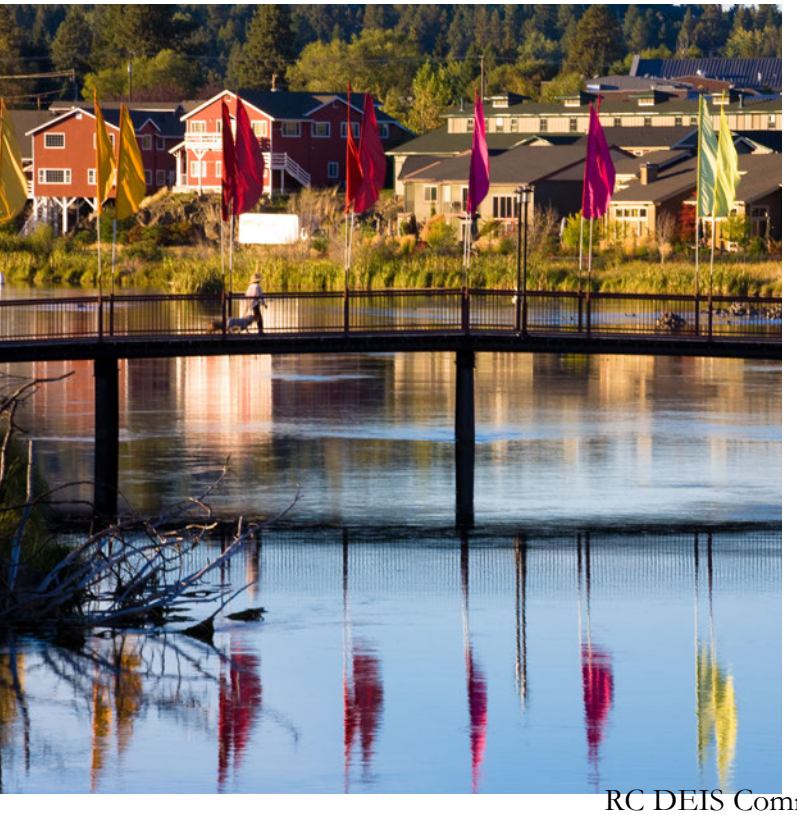
The Bend community collectively possesses the skills, knowledge, and resources that can be harnessed to create solutions to mitigate Bend's climate impact. Success depends on bringing these skills and resources together, jointly assuming responsibility, and developing collaborative solutions. In this spirit, the City worked with the community through extensive public and stakeholder outreach to co-create this Plan.

Grants and local fundraising, including the Oregon Community Foundation, donor-advised funds, and a local campaign coordinated by The Environmental Center provided the majority of the financial support for the project.

The City of Bend appointed a 13-person Climate Action Steering Committee to develop the strategies and actions in this Plan. The Committee represented diverse interests and stakeholders across the community, including the business community, environmental organizations, government agencies and institutions, youth, subject matter experts, and at-large community members.

They conducted workshops with subject matter experts, interested community members, and relevant stakeholders to solicit their ideas and expertise about potential solutions the community could implement to achieve the climate action goals.

The committee solicited feedback on these ideas from the general public at two points during the plan development – first through a community survey in January 2019 and again in July 2019 through an online open house. Additionally, City staff worked with technical consultants to conduct dozens of stakeholder interviews about specific strategies to gather local, Bend-specific data to inform greenhouse gas modeling efforts. For more detail about the plan development, including community engagement efforts, see Appendix A.



Project Timeline

Spring 2018
City hires a Sustainability Coordinator to staff the planning effort and the City Council appoints the 13-person Climate Action Steering Committee.

Summer 2018
The Climate Action Steering Committee develops a vision for the Community Climate Action Plan and creates objectives for different sectors.

Fall 2018
The Committee hosts working group meetings with stakeholders (both community members and experts) to brainstorm potential climate actions for further consideration. These actions describe ways citizens, businesses, and institutions in Bend can reduce their fossil fuel use.

Winter 2019
Members of the general community share feedback on the working groups' proposed action ideas through an online survey.

Spring 2019
The Committee and the City work with partners and technical experts to identify and quantify the impact of 15 specific strategies and actions to include in this Plan.

Summer 2019
The City hosts an online open house to collect a final round of feedback and ideas for additional strategies to include in the Plan. The Committee takes the comments into account, makes final adjustments to the recommendations, and incorporates five additional strategies.

Fall 2019
Committee and City staff meet with the City Council Stewardship Subcommittee to solicit feedback and receive policy guidance on certain elements of this Plan. The Committee then presents the full Plan to City Council for deliberation.

Striving for Equity

The Community Climate Action Plan should aim to improve equity by providing programs that benefit historically disadvantaged and underrepresented community members. These community members, which include low-income residents, communities of color, and other groups who are typically underrepresented in city and community planning efforts, are more vulnerable in the face of a changing climate. According to the U.S. Global Change Research Program's Fourth National Climate Assessment, low-income and other marginalized communities are more likely to suffer more significant impacts from climate change, such as adverse health impacts from poor air quality.

The Climate Action Steering Committee and the City worked to keep equity at the forefront of the climate action plan by getting direct feedback from community organizations that serve disadvantaged populations in Bend and Central Oregon. These conversations sought to obtain feedback on equity issues related to each climate action sector, and potential solutions to make the climate actions more equitable. City staff also had conversations about equity with subject matter experts, stakeholders, and community members who participated in the planning process, including the Climate Action Steering Committee.

Several climate action strategies have specific equity actions intended to make the climate actions more accessible and increase benefits to traditionally underserved populations. These equity actions are further described in Chapter 6 of this Plan. Equity is also used as one of the evaluation criteria for the climate strategies. For a detailed description of the activities completed to prioritize equity while developing this Plan, see Appendix B.

The key takeaway from the equity work completed for this Plan is that the community has more work to do to ensure that this and other planning efforts include representative input from all of Bend's community members and achieve equity goals. In order to do this, the City must invest long term in establishing and maintaining trust and relationships with those community members. How we implement this Plan will determine whether it will benefit the most vulnerable in our community. Evaluating the success of these strategies in achieving equity goals over the next few years will be essential. The City intends to continue to engage with the community organizations serving disadvantaged populations while this Plan is being implemented to evaluate each strategy's equity outcomes. As needed, the City will adapt actions to better meet these equity goals.

2. What are the Impacts of Climate Change in Bend?

Climate Change in Central Oregon – What's Coming?

The Third National Climate Assessment reveals that the Northwest (Washington, Oregon and Idaho) may increase in temperature by 3.3°F to 9.7°F by 2070, when compared to the 1970-1999 period.[1] Warmer average temperatures will cause dry seasons to last longer and become more extreme. Summer, in particular, is expected to be unusually hot with low rainfall. Simultaneously, winter will arrive earlier in the year, and have more precipitation in a shorter time frame. The precipitation will gradually become rain instead of snow, which will decrease snowpack and water supply for streams and rivers during the hotter months of the year.

According to the Deschutes County Natural Hazard Mitigation Plan, the natural hazards that Bend is most vulnerable to are catastrophic wildfires, extreme winter storms, decreased snowpack and drought.[2] The effects of climate change make these natural hazards more likely to occur. Other hazards, such as windstorms and floods also pose serious risk for Bend. The increasing prevalence of these events has negative consequences for human health, poses safety risks and deteriorates quality of life. Additionally, events like catastrophic wildfire in the summer and decreased snowpack in the winter have direct economic detriment to the Bend community, which realizes a significant economic benefit from outdoor recreation activities. A more detailed analysis of climate change in Bend and Central Oregon is provided in Appendix C.

As articulated in the Bend Community Greenhouse Gas Emissions Inventory (Appendix D):

"The Intergovernmental Panel on Climate Change (IPCC), the United Nations body that regularly convenes climate scientists, has identified human activity as the primary cause of the climate change that has occurred over the past few decades and quickened in recent years. Consensus statements from the IPCC suggest that human-caused greenhouse gas emissions (GHG) must be reduced significantly – perhaps more than 50% globally, and by 90% in wealthier nations that are the largest emitters – by mid-century in order to avoid the worst potential climate impacts on human economies and societies that have been projected. The common international goal often referenced to mitigate the worst climate impacts is to limit global average temperature increases to no more than 2°C relative to temperatures at the start of the industrial revolution. As of 2018 – we've already passed the halfway point – average temperatures have increased by more than 1°C since the industrial revolution" (Good Company, 2018).

To prevent the worst impacts from climate change, dramatic changes are needed that will require action at all levels, from international cooperation, through all levels of government, down to the household and individual level.

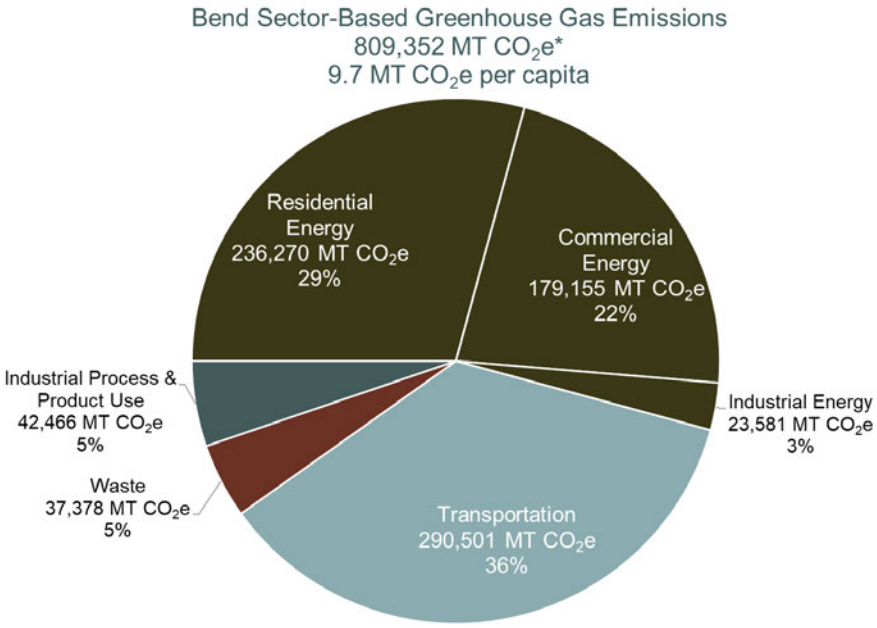
[1] Mote, Philip et al, Northwest: *Climate Change Impacts in the United States: The Third National Climate Assessment*, U.S. Global Change Research Program, (2014): Ch. 21: 489.
[2] *Deschutes County Natural Hazards Mitigation Plan*, Oregon Partnership for Disaster Resilience, May 2015.

3. Bend's Climate Impact

Greenhouse gas emissions are gases released into the atmosphere that trap heat and cause the Earth's temperature to rise. They are emitted into the atmosphere by both human activities and natural processes. The increase in greenhouse gasses in Earth's atmosphere from the combustion of fossil fuels is the main driver behind climate change.

To figure out how to achieve Bend's climate action goals, the City first conducted a community greenhouse gas emissions inventory to understand our baseline. Greenhouse gas emissions can be used as a measurement for fossil fuel use, as the fossil fuel combustion releases greenhouse gas emissions. To learn more about this inventory, see Appendix D. The results of the Community Greenhouse Gas Emissions Inventory tell us that "the Bend community generated 809,352 Metric Tons (MT) CO2e of local, sector-based emissions in 2016. For sense of scale, this quantity of emissions is equivalent to the carbon sequestered annually by over 1 million acres of average U.S. forest – a land area about 50 times the size of the City of Bend." Bend's sector-based emissions[3] are similar in many ways to other communities around Oregon. These emissions are shown in Figure 1, and primarily include emissions from:

Figure 1: Bend's FY16 Sector-Based GHG Emissions



- Combustion of natural gas and electricity use in buildings (green segments)
- Gasoline and diesel combustion in vehicles to transport people and goods (light blue segment)
- Waste, including landfill disposal of community solid waste and wastewater treatment (red segment)
- Local industrial process and product use, including refrigerant gas loss (leaks) from buildings and vehicles, and natural gas loss from the local distribution system (dark blue segment) (Good Company 2018)

[3] Sector-based emissions inventories (or in-geographic boundary inventories) include local emissions, within the City's boundaries, from energy use by homes, businesses, and vehicles as well as emissions from landfilling solid waste and wastewater treatment.

Of Bend's 809,352 MTs of sector-based emissions, 729,508 MT CO2e come from fossil fuel sources, which includes the emissions in the residential, commercial and industrial energy sectors and the transportation sector.[4] The remaining 79,844 MT CO2e come from other greenhouse gases from waste and industrial processes, such as methane. These sectors are not included in Bend's fossil fuel reduction goals, but are an important part of Bend's total climate impact and are therefore addressed in this Plan. When using market-based calculations, these emissions increase to 977,725 MT CO2e total, with 897,881 MT CO2e of the total from fossil fuel sources.[5] Because Bend's Community Climate Action Plan strategies include directly addressing PacifiCorp's resource portfolio, market-based electricity emissions are used as the basis for the calculations in the Plan forecast. Figure 2 shows the different types of emissions sources (fossil fuel, sector-based, and consumption-based) in relation to each other.

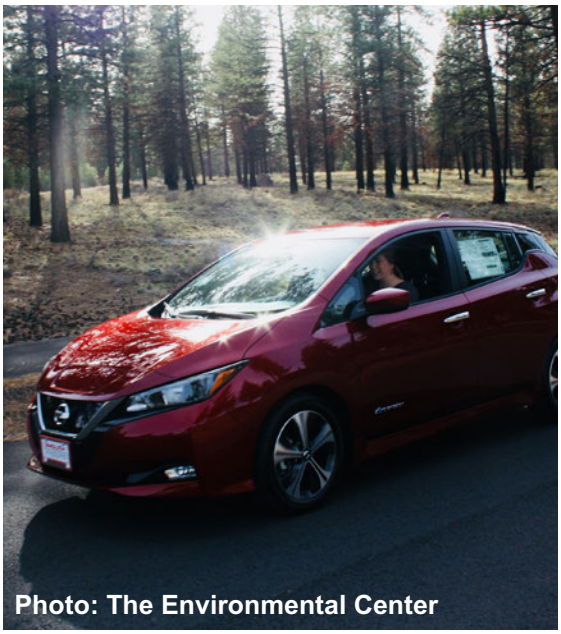
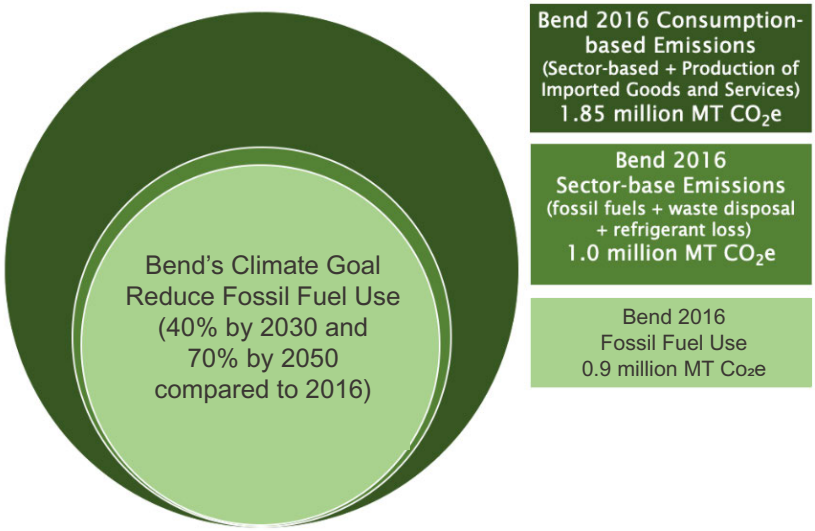


Photo: The Environmental Center

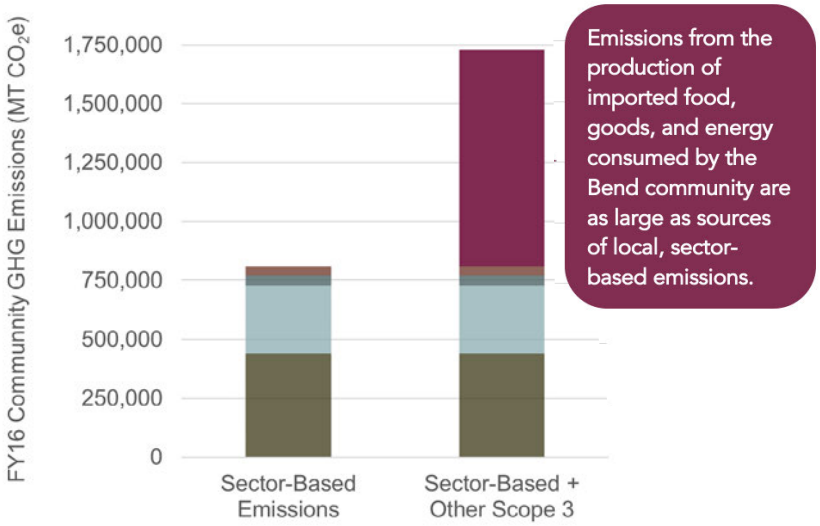
Figure 2: Relative quantities of fossil fuel, sector-based and consumption-based emissions.



Household Consumption and Upstream Energy Emissions

In addition to accounting for sector-based emissions, Bend's Community Greenhouse Gas Inventory also considered emissions that are generated outside of the community during the production of goods, food and services that are consumed in Bend. These emissions total 871,543 MT CO2e. Figure 3 compares the scale of sector-based emissions versus emissions from household consumption and upstream fuel production.[6]

Figure 3: Comparison of sector-based emissions to consumption



[4] Electricity emissions here are calculated using regional average factors or location-based factors.
[5] Electricity emissions here are calculated using PacifiCorp-specific factors or market-based factors.
[6] Sector-based emissions account for "tailpipe" emissions from the combustion of fuels. There are also "upstream" emissions that account for the energy and process emissions during extraction and refinement of fuels.

The scale of the emissions from household consumption is almost equal to sector-based emissions generated locally, which supports the need to address these emissions during the community climate action planning process.

However, because the emissions from household consumption are generated outside of Bend, the community has less control over the energy sources used and the efficiency of production. What the community does have control over is our choice of what kinds of products and services to buy. For example, consumers can choose to buy goods and services from companies that work to lower their carbon emissions. They can also be mindful of their consumption and choose to buy less and reuse what they do buy, rather than constantly buying and disposing of new products.

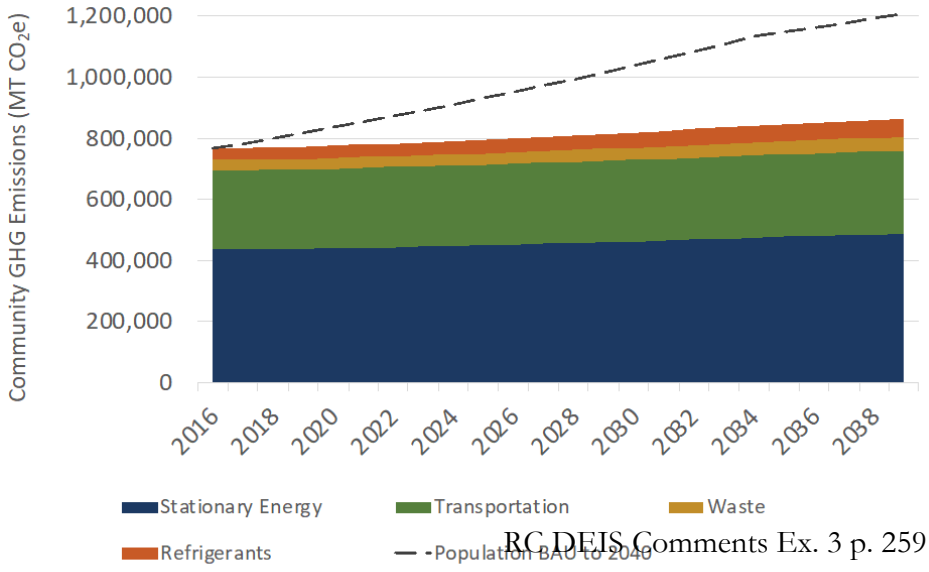
The emissions from non-fossil fuel sources and the emission from household consumption and upstream energy emissions are not included in Bend's fossil fuel reduction goals, since they do not come from direct fossil fuel consumption within the Bend community. However, they are a significant and meaningful part of Bend's climate impact, so there are strategies in this plan that address them.


Photo: Elemental Energy

What happens if we do not change?

In Oregon, we are fortunate to have state policy that drives significant emission reductions in the electricity supply, transportation and building sectors. This allows communities to realize greenhouse gas reductions in absence of additional city or community level action. However, Bend is growing at a dramatic rate. Based on available data, the increased number of people driving, using energy in buildings, and consuming materials in Bend increases the amount of greenhouse gases that Bend is responsible for at a faster rate than the reductions from Oregon's related policies. The community greenhouse gas emissions inventory found that Bend's total greenhouse gas emissions will rise by 13% by 2040 without additional community-level action to mitigate emissions, due to population growth. Figure 4 shows this **"business as usual"** (BAU) emissions scenario. Given this, the Bend community must work to develop local strategies to reduce emissions. State and other government level policy alone will not allow Bend to achieve its greenhouse gas reduction goals.

Figure 4: Greenhouse gas emissions projection for the Bend community in absence of local climate action



"Business as usual" refers to a scenario where we continue to do things as we do currently, without new programs, laws or technologies that reduce our emissions.

4. Climate Action Vision and Principles

Climate Action Vision

The vision for the Community Climate Action Plan is to have neighbors, businesses, and community leaders work together to preserve our natural environment while promoting economic opportunity and resilience for current and future generations.

The goals of this Plan are to:

- Achieve a 40% decrease in fossil fuel use emissions by 2030 and a 70% decrease by 2050 (from a baseline year of 2016).
- Develop and implement a plan that serves as a road map to a sustainable future for our community.
- Harness the resources and talents within Bend's community to take practical action across a wide range of sectors and activities.
- Develop and implement a plan that serves as a road map to a sustainable future for our community.

In order to achieve these goals, this Plan needs to address the following climate action sectors. These four sectors represent the major sources of emissions, based on the baseline greenhouse gas inventory**:**

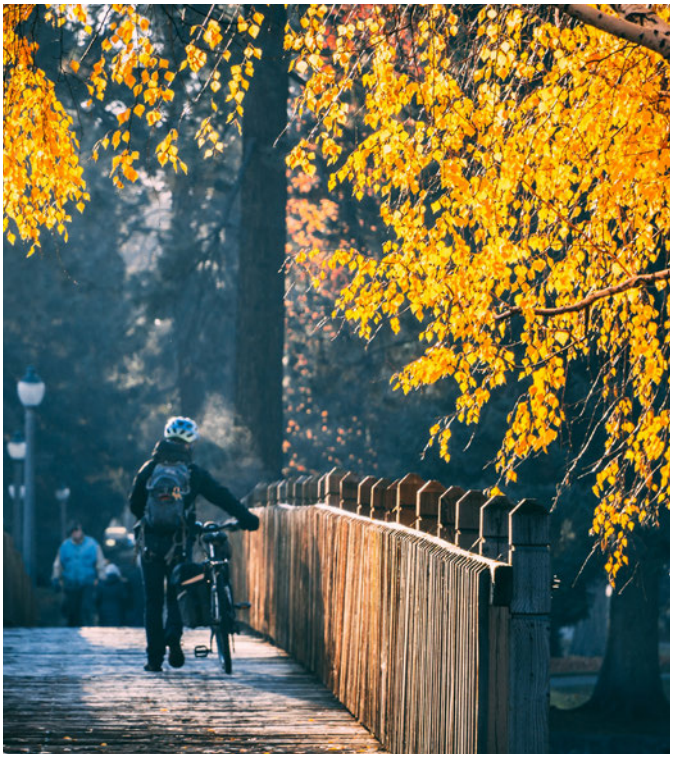
- **Energy Supply:** the source of energy used for transportation, buildings, waste and materials.
- **Energy in Buildings:** the energy used in residential, commercial and industrial buildings.
- **Transportation:** emissions from vehicles.
- **Waste and Materials:** emissions from the production and disposal of materials.

Energy Supply Goals:

1. Demonstrate leadership in the state in accelerating the transition to renewable energy.
2. Identify options, develop projects, and grow a market-driven, renewable energy economy in Bend.
3. Improve access to renewable energy for all Bend residents.
4. Optimize the energy portfolio in Bend to balance carbon intensity, cost and reliability.
5. Invest in local infrastructure and technology to meet energy supply goals.

Energy in Buildings Goals:

1. Increase the energy efficiency of all buildings in Bend.
2. Increase equitable access to energy efficiency programs and benefits for all residents.
3. Increase equitable access to reliable information and education about energy in buildings.
4. Enhance and diversify a skilled building trades work force.
5. Demonstrate leadership in energy efficiency and green buildings in Bend's public agencies.



Transportation Goals:

1. Encourage residents and tourists to change their behavior and use lower carbon transportation options.
2. Decrease total per capita vehicle miles traveled.
3. Improve urban infrastructure to enable more active transportation options.
4. Support innovative forms of low carbon transportation.
5. Pursue opportunities to make Bend's existing transportation system more efficient.

Waste and Materials Goals:

1. Adopt a holistic management approach toward waste and materials usage in Bend.
2. Reduce the upstream impact of waste and materials consumed in Bend.
3. Support the development of waste reduction programs for high-impact waste streams.
4. Expand and improve education programs for waste and materials.
5. Demonstrate leadership in the public sector for developing a progressive materials management culture.

Guiding Principles

How we get there matters. Effective collaboration is vital to achieving the climate action vision and sector goals. Therefore, the plan calls on the community of Bend to lead on climate action through the following principles:

Reflect Local Values

Develop a plan that fits the unique challenges, opportunities and priorities of the Bend community.

Smart about Energy

Reduce our fossil fuel use by promoting efficient and renewable energy consumption. Ensure energy supply reliability and affordability while protecting the natural environment.

Practical, Achievable, Flexible

Create pathways to achieving measurable goals that allow the community to adapt to Bend's needs, capacities and opportunities over time.

Act Inclusively and Respectfully

Consider diverse perspectives and ensure that all viewpoints are considered. Prioritize climate actions that will benefit individuals who have been historically underserved and will be most impacted by climate change.

Promote Economic Wellbeing

Ensure climate actions are well-researched and can have positive outcomes. Build economic resources and resiliency for generations to come.

Create Alliances

Collaborate as a community to build partnerships and find common ground as we develop and implement the Community Climate Action Plan.

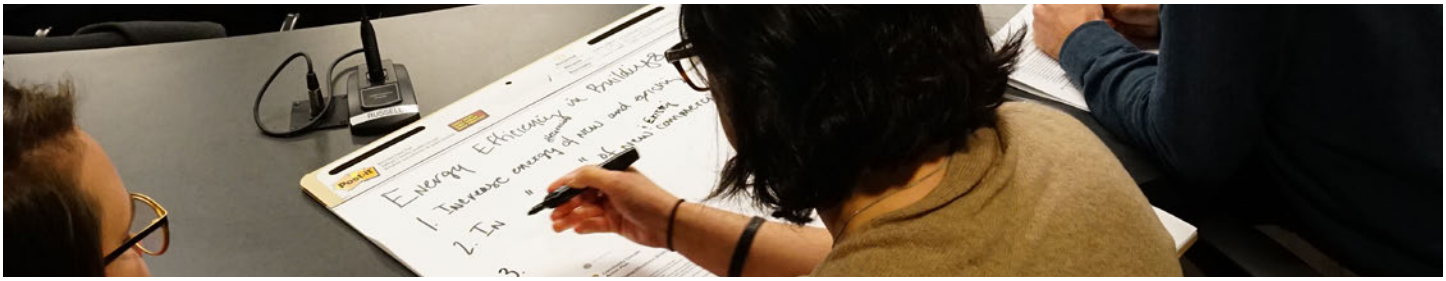
Focus on the Triple Bottom Line

Consider the economic, equity, and environmental impacts of all our decisions.

Keep Eyes on the Horizon

Explore new technologies and approaches. Recognize the long-term nature of some climate actions. Commit to regular evaluation, refinement and collaboration to ensure lasting success.

5. How Will We Get There? Four Areas of Focus



The Climate Action Steering Committee defined the strategies and actions in this Plan through a public engagement process and they describe the ways the community will achieve its climate acton goals. This Plan is organized into four distinct sectors that drive emissions in different ways:

- Energy supply
- Transportation
- Energy in buildings
- Waste and materials

Strategies are higher-level objectives that the community needs to achieve to reduce its fossil fuel use.

Actions are specific policies, programs or projects that can be implemented to help reach these objectives.

Evaluation

Working toward fossil fuel reduction does much more than mitigate Bend's contribution toward climate change. Climate action programs and policies can have triple bottom line benefits, meaning they can provide **social** and **economic** benefits, in addition to **environmental** benefits. This Plan recognizes that the strategies pursued for fossil fuel use reduction should provide economic and social benefits to Bend. With this lens, this Plan brings net benefits for Bend across the community's interests.

The climate action strategies were evaluated with a triple bottom line analysis, which included social, economic and environmental criteria. The results of that analysis are shown in the climate action strategy and implementation tables in Chapter 6 (tables 1-4). The specific evaluation criteria as part of triple bottom line analysis included:

- The technical potential of the strategy to mitigate greenhouse gas emissions, measured in the degree to which the strategy conserves or restores natural resources.[7]
- The cost to mitigate greenhouse gas emissions with the strategy, on a per metric ton (or 2,200 lbs) basis, measured in dollars per metric ton of greenhouse gas emissions reduced.[8]
- Six co-benefits selected by the Committee, which are further described in the following section.[9]

[7] The technical analysis focused on the technical potential to reduce greenhouse gasses and the estimated cost per tonne, as this is the focus of this Plan. To calculate these values, data specific to Bend was collected from the community through a series of stakeholder calls with other government agencies, utilities, and local community organizations and businesses.

[8] The cost to mitigate a metric ton of carbon dioxide equivalent is shown in life cycle costs. It takes into account the return on investment to the community per metric ton of carbon dioxide.

[9] The co-benefits were evaluated on a qualitative scale as a means to characterize the benefits of the strategies and to evaluate the strategies' total benefit in relation to each other.

Co-benefits

The co-benefits of each strategy are the positive impacts the strategy will create beyond its effect on reducing greenhouse gas emissions. Describing the co-benefits of each strategy shows us that investing in greenhouse gas reduction is beneficial not just for the environment but for our health, the economy, and equity. The co-benefits evaluated for this Plan are:

Economic vitality

Measured in job creation.

Affordability

Measured in the relative cost and benefit to the person or entity bearing the cost.

Supports the natural environment

Measured in the degree to which the strategy conserves or restores natural resources.

Social equity

Measured in the degree to which the strategy equitably distributes benefits to historically underserved community members.

Community health and safety

Measured in the degree to which the strategy provides health and safety benefits to the community.

Adaptation and resilience

Measured in the degree to which the strategy helps the community prepare for and recover from stressors such as drought and wildfire.

Many of the strategies in this Plan have net positive returns to the community through cost savings from using less energy and materials over time. For detail on calculations, data, methodology and assumptions, see Appendix F.

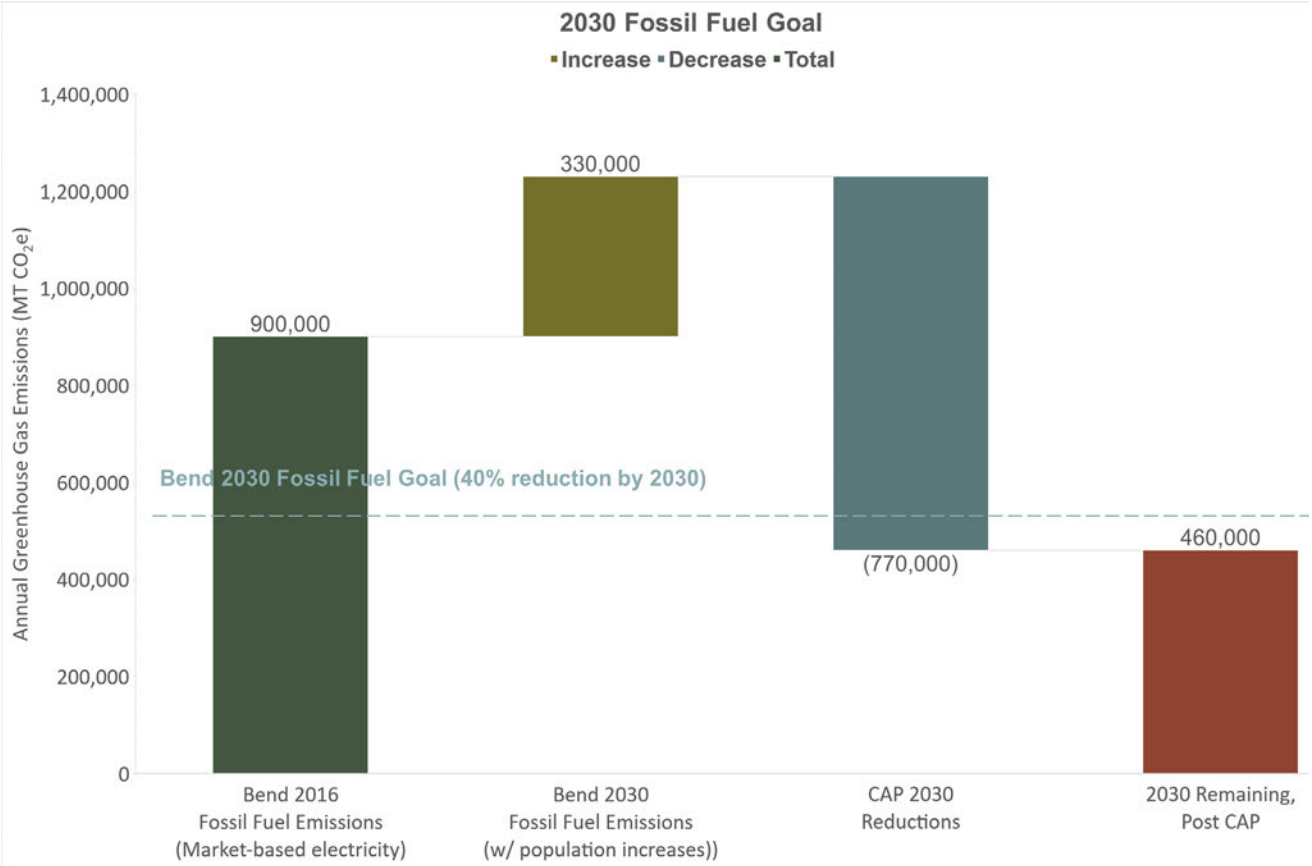
The Impact of Bend's Community Climate Action Plan

Bend's current climate goal is focused on local sources of fossil fuel emissions. Specifically, the Bend City Council set climate action goals to **reduce fossil fuel use community wide by 40% by 2030 and by 70% by 2050.** Bend's goal is focused on the largest local sources of emissions under direct community control.

Not all sources of emissions included in Bend's 2016 Greenhouse Gas emissions Inventory are covered by the goal (something that is common for many communities) as these sources can be located outside the community and can be more difficult to control. Based on the fossil fuel goals, Bend's target is to decrease its generation of market-based fossil fuel emissions to 540,000 metric tons of market-based fossil fuel emissions by 2030, and to 270,000 metric tons of emissions by 2050.

If the Bend community does not take action on climate change, Bend will generate roughly 1,230,000 metric tons of market-based greenhouse gas emissions from fossil fuel sources in 2030, with expected population growth. If Bend's Plan is implemented as planned and the intended outcomes are achieved, the community is forecasted to reduce its fossil fuel use by 770,000 metric tons annually of emissions by 2030. This represents a 49% reduction from 2016 baseline emissions, surpassing Bend's 2030 climate goal.

Figure 5: Bend Community Climate Action Plan progress towards 2030 climate action goal



By 2050, if this Plan is implemented as planned and the intended outcomes are achieved, Bend is forecasted to reduce its fossil fuel use by 1,300,000 metric tons of market-based fossil fuel emissions and generate 460,000 metric tons of emissions. Unfortunately, with expected population increases, this represents a 49% reduction from the 2016 baseline emissions as well, falling short of the 70% fossil fuel reduction goal. This is partly because a statewide policy requiring the electricity supply to phase out coal will be implemented by 2030, and emissions reductions realized by this state policy will decrease on an annual basis after 2030.

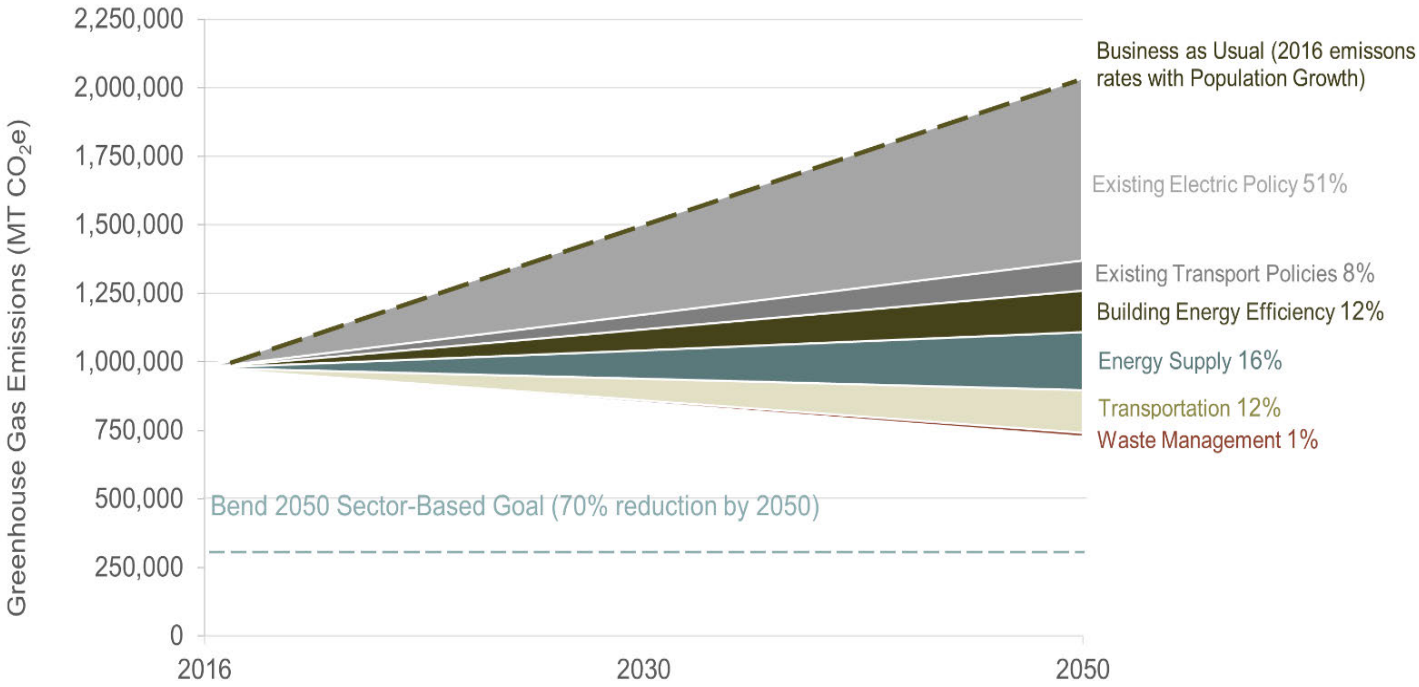
Bend's climate action strategies proposed in this Plan continue to reduce fossil fuel use through 2050, but roughly at a pace that just offsets the increased population growth. Falling short of the 2050 reduction goal incites a need for the Community to remain committed to climate action over the long term. Bend must update this Plan regularly and identify more climate strategies over time. With improvements in technology, data, and forecasting, updating this Plan in future years should provide opportunities for the Community to achieve the ultimate reduction goals.

Several of the strategies in this plan reduce greenhouse gas emissions that do not come from fossil fuel sources, but do generate local greenhouse gas emissions. These additional local emissions include emissions from waste and from refrigerant loss in industrial processes. Figure 6 shows the forecast emission reduction contributions from local sector-based sources if this Plan is fully implemented.

When considering all of the sector-based emissions, the majority of the emissions reductions are driven by decarbonizing the energy supply. A full 67% of the forecast emissions come from the energy supply sector, with 51% of that driven by existing Oregon electricity policy and the remaining 16% coming from other energy supply related strategies detailed in Chapter 6. Another 12% of the total forecast reductions come from strategies that improve the energy efficiency of buildings. 20% come from reducing fuel use in the transportation sector, and 1% come from improving waste recovery. Figure 7 shows how much each category of emissions contributes to the overall forecast reductions.

Figure 6: Bend Community Climate Action Plan progress towards Bend's 2050 climate action goal. This plan achieves a 49% reduction in fossil fuel consumption compared to the 2016 baseline.

Figure 7: Forecast emission reduction contributions from sector-based emissions.



6. Strategy and Action Implementation Details

Fully implementing all of the Community Climate Action Plan strategies goes beyond the authority of any individual entity or person. The City of Bend intends to take a leadership role. It has the authority and takes responsibility for many of the specific climate actions but cannot take action on all of them. Many of the strategies require other public agencies, community organizations, and city franchisees to take the lead on implementation. Successfully reaching the maximum technical potential of each strategy will also require that individual residents and businesses in the community participate in new programs or systems that are offered by the implementing partners.

The following sections describe how the climate action strategies will be implemented and who is responsible for each.

These sections also provide other details on the strategies, including:

- Specific implementation actions
- The technical potential for each strategy to reduce emissions, assuming the strategy target is achieved
- The life cycle savings or expenditures that will be incurred by implementing each strategy
- Progress metrics that provide ways of evaluating movement toward reaching these goals
- Strategy targets that quantify specific goals for each strategy
- Co-benefits of each strategy

For each sector, there is also a description of relevant equity actions and equity outcomes. **Equity actions** are actions that the City or other implementation leads will take to make it easier for traditionally underserved populations to implement the climate strategies. **Equity outcomes** describe how the implementation of a climate strategy will lead to a more equitable system.

Key to the Implementation Details Tables

Implementation Responsibilities

- City of Bend
- Public Agencies
- Community Partners
- Private Developers
- Utility
- Oregon Department of Energy
- Workforce Development Agencies
- Tourism Agencies
- Deschutes County
- Lending Agencies
- Businesses
- City and State Partners
- Cascades East Transit
- Energy Trust of Oregon
- Waste Haulers
- Oregon Department of Environmental Quality

Cumulative Emission Reductions Potential (in metric tons of emissions)

200,000

Savings or Expenditure Range (per metric ton of emissions reduced)

- Savings
- Expenditures

Co-benefits

- Economic Vitality
- Affordability
- Supports the Natural Environment
- Community Health and Safety
- Adaptation and Resilience
- Social Equity

Energy Supply

Energy supply refers to the sources of the energy we use to power and heat our buildings, power our modes of transportation, and produce the materials we use and foods we consume. Different energy sources have different levels of greenhouse gas emissions. Switching from a carbon-intensive source of energy, such as coal or oil, to lower-carbon sources, such as renewable wind and solar energy, will reduce our greenhouse gas emissions.

In Bend, our energy supply is provided to us by our franchised utilities. We have two electricity utilities, Pacific Power and Central Electric Cooperative. We have one gas utility, Cascade Natural Gas. The greenhouse gas emissions that come from electricity are driven by what sources the utility uses to generate electricity, which change over time. A significant portion of Pacific Power's electricity grid today is supplied by coal resources, which have a high emissions factor. Pacific Power is required to eliminate coal resources in Oregon by 2035 and to supply the grid with 50% renewable resources by 2040 as a result of Oregon's Clean Energy and Coal Transition Act. Central Electric Cooperative procures most of its electricity from Bonneville Power Administration which generates mostly hydroelectric and nuclear power, which are low in greenhouse gas emissions.

Energy Supply Strategies

Strategies that decarbonize Bend's energy supply will contribute the most of all the strategies in this Plan to Bend's forecast emissions reductions. These strategies reduce emissions by 880,000 MT CO2e, which represents a 67% reduction from the total sector-based emissions in 2050 (and a 69% reduction in emissions from buildings). This Plan reduces emissions from the energy supply by committing to providing 100% renewable electricity to the Bend community, expanding distributed renewable energy resources, establishing a natural gas offset program, and investing in capturing renewable natural gas through a biodigester project at the wastewater treatment facility. Additionally, the Bend community will greatly benefit from the Clean Energy and Coal Transition Act. This law contributes 51% of Bend's forecast reductions. Table 1 shows the strategies that the Bend community will take to reduce greenhouse gas emissions from its energy supply.

Energy Supply

Table 1. Energy Supply - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY: *ES1- Provide 100% renewable electricity supply to the community*						
ES1A – Develop a roadmap to **achieve a 100% renewable electricity supply** for the community.	Lead: City of Bend Partners: Utility	• Percent of community subscribed to renewable power. • Total load and percentage of total load served by renewables.	100% renewable energy procured by 2025.	4,410,000 ●●●●● x4.4	$10 to $35	10, 7.5, 5, 2.5
STRATEGY*: ES2 - Contract for a natural gas offset program for community gas use*						
ES2A – Develop a program that allows residential and commercial customers to offset their natural gas use.	Lead: Utility Partners: Not yet identified	• Percentage of the community households and organizations subscribed to gas that have offset emissions. • Total number and percentage of therms offset.	25% of customer participation in the program.	1,860,000 ●●●●● x1.8	$20 to $45	10, 7.5, 5, 2.5
STRATEGY*: ES3 - Expand distributed commercial and residential solar photovoltaics (PV)*						
ES3A – Increase community education on renewable energy and available incentives by developing and delivering educational programs.	Lead: Community Partners Partners: Energy Trust of Oregon, Utility	• Number and percentage of households educated.	32 Added MW of solar PV by 2036. 1.6 MW of solar PV added annually.	200,000 ●○○○○	$75 to $50	10, 7.5, 5, 2.5
ES3B – Promote renewable energy incentives offered by utilities by providing information about these incentives to individuals and companies applying for building permits.	Lead: City of Bend Partners: Energy Trust of Oregon, Utility	• Number and percentage of permit applicants that have been reached.				
ES3C – Create new incentive packages that increase the installation of renewable energy systems on residential and commercial buildings	Lead: City of Bend Partners: Energy Trust of Oregon, Private Developers, Utility	• Number and percentage of new buildings with installations. • Number and percentage of existing buildings with installations. • Total generation capacity of installed systems.				

Note:
This Target, Cumulative Emission Reductions Potential, Savings or Expenditure Range, and Co-benefit data is based on all eight actions in ES3.

City of Bend · Community Partners · Utility · Energy Trust of Oregon · Private Developers · Lending Agencies · Deschutes County · Public Agencies

Savings · Expenditures · Economic Vitality · Affordability · Supports the Natural Environment · Community Health and Safety · Adaptation and Resilience · Social Equity · Workforce Development Agencies

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Energy Supply

Table 1. Energy Supply - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: ES3 (cont.) - Expand distributed commercial and residential solar photovoltaics (PV)*						
ES3D – Create revolving loan funds to finance renewable energy projects. These funds will be more accessible than current loan options to low- and moderate-income residents. The City will investigate different options for fund administration.	Lead: City of Bend Partners: Lending Agencies	• Total dollars distributed through fund annually. • Number and percentage of buildings using loan program.				
ES3E – Develop community solar projects that residents can subscribe to for access to offsite solar energy.	Lead: Community Partners Partners: Utility, City of Bend	• Number and total generation capacity of projects. Total number of subscribers for each project.				
ES3F – Pilot microgrid and battery storage projects powered by renewable energy that can operate independently of the energy grid.	Lead: City of Bend, Community Partners Partners: Utility	• Number of microgrids in total. • Total installed renewable generation capacity inside of microgrids. • Percentage of local load served by microgrids.	32 Added MW of solar PV by 2036. 1.6 MW of solar PV added annually.	200,000	$75 to $50	
ES3G – Support and expand workforce development programs in renewable energy trades that are delivered by community organizations.	Lead: Community Partners, Workforce Development Agencies Partners: Not yet identified	• Number of people trained per year. • Number and percentage of those trained that are fully employed in this profession.				
ES3H – Create a commercial, property-assessed clean energy program that allows renewable energy projects to be financed through property tax assessment.	Lead: Deschutes County Partners: Not yet identified	• Total installed generation capacity as percentage of total commercial load. • Number of participants in program.				

Note: *This Target, Cumulative Emission Reductions Potential, Savings or Expenditure Range, and Co-benefit data is based on all eight actions in ES3.*

City of Bend | Community Partners | Utility | Energy Trust of Oregon | Private Developers | Lending Agencies | Deschutes County | Public Agencies

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity | Workforce Development Agencies

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Energy Supply

Table 1. Energy Supply - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: ES4 - Build/explore a biodigester at the wastewater treatment facility*						
ES4A – Build a biodigester at the wastewater treatment facility, after confirming feasibility of the project.	Lead: City of Bend Partners: Not yet identified	• Percent of onsite load served by the digester, • Gallon equivalents of fossil fuel displaced in transportation or electricity produced.	72,000 therms annual production.	140,000	$10	10, 7.5, 5, 2.5
STRATEGY*: ES5 - Install solar panels on public buildings*						
ES5A – Install solar panels on public buildings to demonstrate public sector leadership.	Lead: City of Bend, Public Agencies Partners: Not yet identified	• Number and percentage of buildings with rooftop solar. • Total installed capacity of renewables. • Percentage of total load that is served by rooftop solar.	1.2 MW of additional capacity on schools. 0.710 MW of additional capacity on City buildings.	20,000	$50	10, 7.5, 5, 2.5

City of Bend | Community Partners | Utility | Energy Trust of Oregon | Private Developers | Lending Agencies | Deschutes County | Public Agencies

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity | Workforce Development Agencies

*Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.

Equity Actions and Outcomes

The following equity actions will be taken to make strategies and actions in this sector more accessible and equitable:

- Build a community solar project so renters and those without solar access can access renewable energy, and ensure a rate structure that is accessible for low- and moderate-income households.
- Promote existing utility incentives for landlords to add renewable energy to their properties.
- Promote renewable energy incentives that benefit for low- and moderate-income residents.
- Engage in outreach campaigns in multiple languages that inform communities not reached by traditional methods about ways they can implement these strategies. For example, conducting an outreach campaign to inform communities of incentives for energy-efficient building upgrades that benefit residents with low- and moderate-incomes.

The strategies and actions in this sector will lead to the following equity outcomes:

- Job training for underemployed individuals in renewable energy trades.
- More accessible loans for residents with low- and moderate-incomes to make improvements to their energy supply.

Energy in Buildings

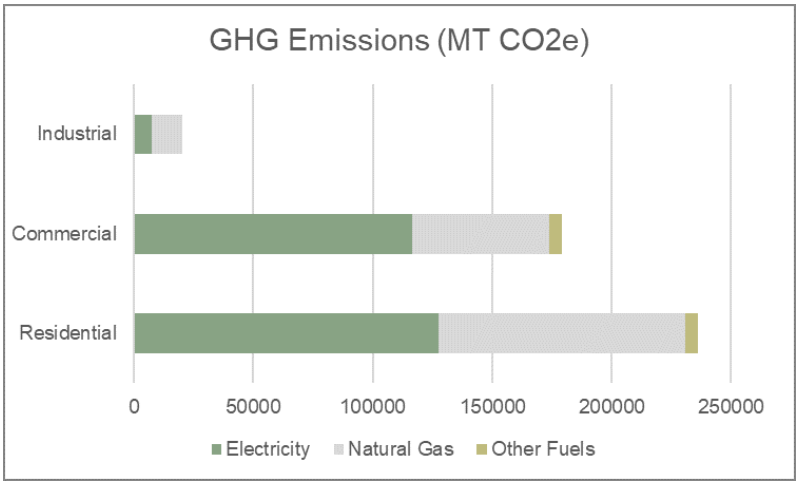
The energy we use in our buildings makes up 54% of Bend's local (sector-based) fossil fuel use, making it the largest contributor to greenhouse gas emissions in the community. Residential buildings produce 29% of overall emissions. Commercial buildings produce 22% of overall emissions, and industrial buildings are relatively low at 3% overall emissions.

Almost everything we do and use in buildings consumes energy – from our lights, heating and cooling systems, to our appliances and electronics. In Bend, we primarily use natural gas and electricity as the energy sources for our buildings. Electricity represents 58% of the greenhouse gas emissions in this sector, while natural gas represents 40%. The remaining 2% comes from other fuels like propane (Good Company, 2018).

Additionally, Bend is growing quickly and adding many new homes and commercial buildings over the next several years. Because of this, Bend must also focus on implementing methods to reduce the impact of new buildings, in addition to existing buildings.

We can reduce our greenhouse gas emissions in this sector by improving our buildings so they use less energy to meet our needs and by switching to renewable energy like wind, solar, and renewable fuels. Figure 8 shows the breakdown of energy consumption in the residential, commercial, and industrial sectors. Industrial energy use in Bend is relatively low compared to energy use in residential and commercial buildings, which means that individuals have a large opportunity to make an impact in their homes and businesses. The strategies in this Plan are primarily focused on commercial and residential building strategies to take advantage of these opportunities.

Figure 8: Electricity and natural gas consumption by building type in Bend community.



Energy in Buildings Strategies

Increasing the energy efficiency of Bend's new and existing buildings is forecast to reduce emissions by roughly 150,000 MT CO2e by 2050. These strategies contribute 12% of forecasted sector-based emissions. Efficiency is a particularly cost-effective climate action in the near-term as PacifiCorp works to decarbonize its grid. Building energy efficiency is also one of the only components of the plan that reduces emissions from community combustion of natural gas.

The Bend community will reduce emissions through energy efficiency by expanding voluntary uptake of energy efficiency upgrades, implementing voluntary and mandatory benchmarking programs for commercial and residential buildings, supporting the advancement of a higher-performing building energy code, and promoting smaller home sizes. While energy efficiency strategies represent a reduction of roughly 12% of total emissions from buildings in Bend, strategies to decrease emissions from the energy supply also decrease emissions from buildings in Bend. As a result, the total amount of forecasted emission reductions from buildings includes reductions from both sectors. Table 2 describes the strategies that the Bend community will take to reduce emissions in its buildings.

Energy in Buildings

Table 2. Energy in Buildings - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY: *EB1 - Support policies that increase energy efficiency of buildings*						
EB1A – Participate in code update processes and vote for advancing energy efficiency in codes to help achieve the State's goal of having a net zero ready building code by 2023.	Lead: City of Bend Partners: Not yet identified	• Number of new buildings that are net zero ready. • Percentage of building stock that is net zero ready.	Annual reduction of 6,000 MWh and 275,000 therms.	1,320,000	Not available	
EB1B – Develop and deliver outreach and education campaigns to promote net zero ready building standards.	Lead: Community Partners Partners: Not yet identified	• Number of households and organizations reached with the message. • Number of developers and builders reached with the message. • Number and percentage of new building starts that are net zero ready before the new code is implemented.				
STRATEGY: *EB2 - Improve uptake of voluntary energy efficiency projects in buildings*						
EB2A – Increase community education on energy efficiency and available energy efficiency incentives by developing and delivering educational programs.	Lead: Community Partners Partners: Energy Trust of Oregon, Utility	• Number and percentage of residents that have engaged in outreach and education programs.	Annual reduction of 6,000 MWh and 125,000 therms.	1,180,000	$50 to $0	
EB2B – Promote energy efficiency incentives offered by utilities by providing information about these incentives to individuals and companies applying for building permits.	Lead: City of Bend Partners: Energy Trust of Oregon, Utility	• Number and percentage of residents that have received the information.				

Note: *This Target, Cumulative Emission Reductions Potential, Savings or Expenditure Range, and Co-benefit data is based on all six actions in EB2.*

City of Bend · Community Partners · Utility · Energy Trust of Oregon · Private Developers · Technical Experts · Lending Agencies · Workforce Development Agencies · Oregon Department of Energy

Savings · Expenditures · Economic Vitality · Affordability · Supports the Natural Environment · Community Health and Safety · Adaptation and Resilience · Social Equity

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations see Appendix D.*

Energy in Buildings

Table 2. Energy in Buildings - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: EB2 (cont.) - Improve uptake of voluntary energy efficiency projects in buildings*						
EB2C – The City will work with private developers and technical experts to **create new incentives and programs to expand energy efficiency projects in residential and commercial buildings.**	Lead: City of Bend Partners: Energy Trust of Oregon; Private Developers; Utility	• Number and percentage of building projects that have utilized incentives.				
EB2D – Create revolving loan funds to finance energy efficiency projects. These funds will be more accessible than current loan options to residents with low or moderate incomes and the City will investigate different options for fund administration.	Lead: City of Bend Partners: Lending Agencies	• Total dollars distributed through fund annually. • Number and percentage of buildings using loan program.	Annual reduction of 6,000 MWh and 125,000 therms.	1,180,000	$50 to $0	
EB2E – Support workforce development programs in energy efficiency trades that are delivered by community organizations.	Lead: Community Partners; Workforce Development Agencies Partners: Not yet identified	• Number of people trained per year. • Number and percentage of trained people fully employed in Bend.				
EB2F – Explore options for demand response programs, which encourage consumers to adjust their energy use during peak energy hours.	Lead: Utility Partners: Not yet identified	• Number and percentage of buildings using the demand-side management strategies.				

Note: *This Target, Cumulative Emission Reductions Potential, Savings or Expenditure Range, and Co-benefit data is based on all six actions in EB2.*

City of Bend | Community Partners | Utility | Energy Trust of Oregon | Private Developers | Technical Experts | Lending Agencies | Workforce Development Agencies | Oregon Department of Energy

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity

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Energy in Buildings

Table 2. Energy in Buildings - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: EB3 - Implement benchmarking and disclosure programs for energy performance*						
EB3A – Develop a home energy score program that allows homes to be compared based on their energy use and energy efficiency, leveraging industry stakeholders, the U.S. Department of Energy standard home energy scoring tools, and industry best practice.	Lead: City of Bend Partners: Oregon Department of Energy	• Number and percentage of housing units with energy scores available. • Trend of average Home Energy Score.	Annual reduction of 3,000 MWh and 200,000 therms.	1,000,000	$50 to $50	10, 7.5, 5, 2.5
EB3B – Develop voluntary disclosure and benchmarking programs for public and commercial buildings that allow them to track, report, and make their energy use public. Develop rules and requirements with input from industry stakeholders and community.	Lead: City of Bend Partners: Oregon Department of Energy	• Number and percentage of buildings participating in the program. • Average energy trends of buildings participating in the program.				
EB3C – Support and expand low cost energy audit programs. Identify barriers to utilizing existing programs and ways to address them.	Lead: Community Partners Partners: Not yet identified	• Baseline number of audits per year. • Number and percent growth in baseline number of audits delivered.				
STRATEGY*: EB4 - Promote smaller homes and denser housing options through incentives*						
EB4A – Develop incentives that encourage private developers to build smaller housing options.	Lead: City of Bend Partners: Private Developers	• Number and percentage of new dwellings that are accessory dwelling units. • Average square footage of dwelling units by year.	Average home size is 1,600 square feet.	410,000	$700	10, 7.5, 5, 2.5

City of Bend | Community Partners | Utility | Energy Trust of Oregon | Private Developers | Technical Experts | Lending Agencies | Workforce Development Agencies | Oregon Department of Energy

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity

*Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.

Equity Actions and Outcomes

The following equity actions will be taken to make strategies and actions in this sector more accessible:

- Engage in intentional outreach campaigns in multiple languages that inform communities not reached by traditional methods about ways they can implement these strategies. For example, conducting an outreach campaign to inform communities of incentives for energy-efficient building upgrades that benefit residents with low- and moderate-incomes.
- Promote existing utility incentives for landlords to improve the energy efficiency of rental properties.
- Promote incentives for manufactured homes.
- Encourage lower costs of homes by creating incentives to promote smaller homes.

The strategies and actions in this sector will lead to the following equity outcomes:

- Job training for underemployed individuals.
- More accessible and affordable energy audits.
- Transparency in the relative energy consumption of different homes. This is because low- and moderate-income residents face a larger energy burden and are disproportionately impacted by inefficient homes.
- More accessible loans for residents with low- and moderate-incomes to undertake energy efficiency upgrades to their homes.
- Encourage lower costs of homes by creating incentives to promote smaller homes.

Transportation emissions make up 36% of local greenhouse gas emissions in Bend. These emissions come from the tailpipes of passenger vehicles, commercial service vehicles, freight vehicles, and transit vehicles, and include both Bend residents and visitors. Most emissions from transportation are from passenger cars and trucks owned by Bend residents. Roughly 66% of the greenhouse gas emissions from passenger transportation are trips that take place entirely within the City's boundary, while about 33% of the emissions come from trips that either start or end outside of the boundary. Total transportation emissions are increasing as the Bend community continues to grow.

Transportation Strategies

This Plan will reduce emissions from the transportation sector by 270,000 MT CO2e in 2050, which contributes 20% of the total forecast emissions reductions. Within the transportation sector, these strategies lead to a 44% decrease in emissions compared to a business as usual scenario. Existing Federal and Oregon transportation policies will reduce emissions by increasing the fuel economy of vehicles (Federal Fuel Economy Requirements) and reducing the carbon intensity of fuels used in Oregon (Oregon Clean Fuels Program). Existing transportation policies represent 8% of Bend's total sector-based forecast reductions. The community will reduce local emissions further by encouraging more trips on foot, bike, transit, electric vehicles, and carpooling or vanpooling. Local climate action policies represent the remaining 12% of Bend's sector-based forecast reductions.

Figure 9: This plan is forecast to reduce transportation emissions by 270,000 metric tons annually in 2050.

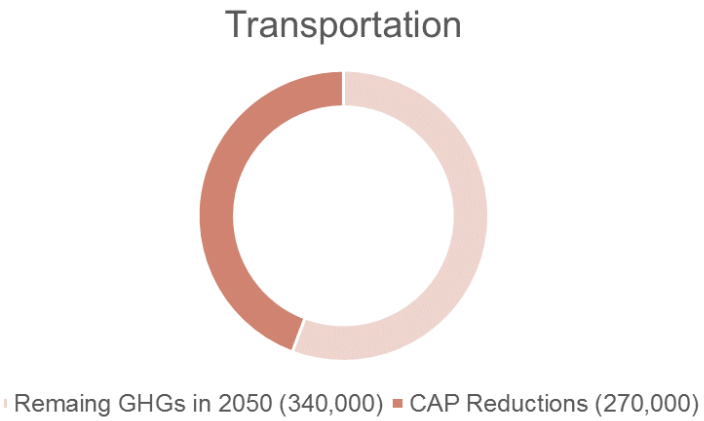
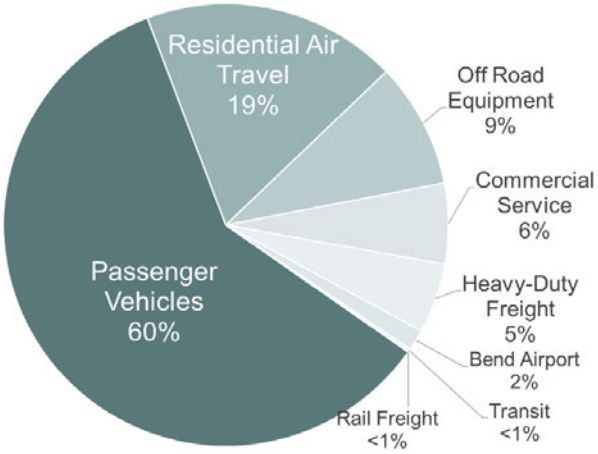


Figure 10: Breakdown of greenhouse gas emissions in the transportation sector by type of vehicle.



Transportation

Table 3. Transportation - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: T1 - Support the transition to electric vehicles (EVs) with an EV Readiness Plan*						
T1A – Develop a plan that anticipates EV growth, determines necessary charging infrastructure to accommodate this growth, and defines mechanisms to encourage the expansion of public and private charging infrastructure. Update code, standards, and specifications to achieve necessary infrastructure.	Lead: City of Bend Partners: Not yet identified	• Number and percentage of total vehicles registered in Bend that are EVs. • Annual vehicle registrations and number and percentage that are EVs.	25% of vehicle miles travelled (VMT) are with electric vehicles.	1,160,000	$200 to $50	10, 7.5, 5, 2.5
STRATEGY*: T2 - Increase bike and pedestrian trips*						
T2A – Prioritize Bend's Bike, Pedestrian, and Complete Streets Policies in the Transportation System Plan. These policies include expanding bike and pedestrian infrastructure, especially in historically underserved neighborhoods.	Lead: City of Bend Partners: Not yet identified	• Based on TSP metrics for each related policy.	10% of VMT are by biking and walking. 15% of trips taken are by bicycle and 15% of trips taken are by walking.	690,000	$60	10, 7.5, 5, 2.5

City of Bend · Public Agencies · Community Partners · Cascades East Transit

Savings · Expenditures · Economic Vitality · Affordability · Supports the Natural Environment · Community Health and Safety · Adaptation and Resilience · Social Equity

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Transportation

Table 3. Transportation - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: T3 - Increase transit ridership*						
T3A – Create a Mobility Hub program to improve access to a wide range of travel options and support multimodal lifestyles. These hubs combine multiple modes of transportation together in one physical location, often clustered around a high-frequency public transit stop. Typical components include carshare stations, bike parking, wayfinding elements and universal fare payment via a single smartcard or mobile app.	Lead: City of Bend, Cascades East Transit Partners: Not yet identified	• Number and percentage of Mobility Hubs planned. • Number and percentage of Mobility Hubs developed.				
T3B – Create high capacity transit corridors that increase frequency of service on major routes**.**	Lead: Cascades East Transit Partners: Not yet identified	• Based on TSP metrics.	Transit makes up 2% of VMT.	490,000	$50	
T3C – Expand transit service coverage consistent with the regional transportation master plan.	Lead: Cascades East Transit Partners: Not yet identified	• Based on regional transportation master plan metrics.				
T3D – Coordinate with school district to encourage use of public transit for getting to school.	Lead: Public Agencies Partners: Cascades East Transit	• Percent mode share of children riding public transit to school.				

City of Bend | Public Agencies | Community Partners | Cascades East Transit

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity

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Transportation

Table 3. Transportation - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: T4 - Promote ride sharing*						
T4A – Encourage the use of carpooling, vanpooling, and other modes of ride sharing.	Lead: Partners: Not yet identified	• Annual number of carpools, vanpools, or other shared trips taken.	6% of VMT are shared trips.	140,000	$140	10, 7.5, 5, 2.5
STRATEGY*: T5 - Convert City and other public agency fleets to electric vehicles and alternative fuels*						
T5A – Public agencies will convert fleets to electric and alternative fuel vehicles as total cost of ownership allows.	Lead: Partners: Not yet identified	• Number and percentage of sedans converted to EVs. • Carbon intensity of heavy duty fuel that are low carbon. • Total annual emissions from vehicle fuels.	100% of gas use is substituted with electric. 100% of diesel is substituted with renewable diesel.	50,000	$200 to $75	10, 7.5, 5, 2.5

City of Bend | Public Agencies | Community Partners | Cascades East Transit

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and safety | Adaptation and Resilience | Social Equity

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Equity Actions and Outcomes

The following equity actions will be taken to make strategies and actions in this sector more accessible:

- While implementing transportation improvements, follow the set of equity policies developed in Bend's Transportation System Plan to ensure that these improvements promote equity in the community.
- Prioritize complete streets – or streets that support all modes of transportation – and active transportation projects in neighborhoods that have higher proportions of low-income residents and residents of color.
- Create programs that improve access to transit for low-income residents (i.e. transit passes).
- Promote affordable and accessible housing development along transit routes.

The strategies and actions in this sector will lead to the following equity outcomes:

- Improved access and safety for transportation choices beyond private cars, including transit, walking, biking and others.

The goods and services we use in our daily lives have a huge effect on the environment and generates large amounts of greenhouse gas emissions. This includes the food we eat, clothes we wear, electronics we use, furniture we own, and materials we use to build our houses. Most of what we use eventually ends up in the landfill, where it breaks down and releases greenhouse gas emissions. Emissions from the landfill make up 5% of the total greenhouse gases emitted in the Bend community. Recovering or diverting materials from the landfill can help reduce the emissions associated with waste.

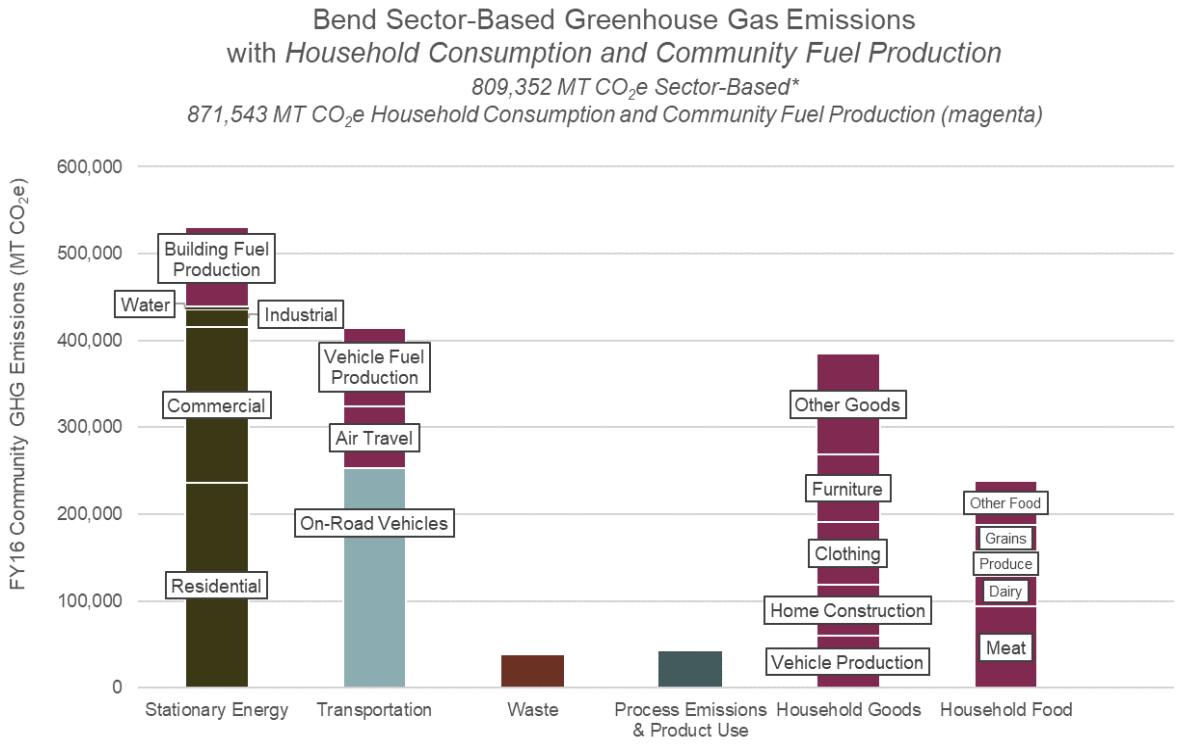
Emissions from the production of imported food, furniture, clothing, vehicles, fuel and home-building materials that are bought and used in Bend, but produced outside of the community, generate substantial emissions. The emissions add up to 871,543 MT CO2e, which is actually more than the emissions that occur within the community. Emissions that occur outside of the community boundaries are more difficult to manage because the community has less control over the associated production activities, but Bend residents can mitigate these emissions in part by consuming less of these things or consuming things that have a lower impact.

Waste and Materials Strategies

Emissions from waste and materials are not fossil fuel-based emissions, so the strategies in this Plan that reduce waste and material consumption do not contribute to the fossil fuel reduction goals. However, there are other greenhouse gas emissions from waste and materials that are produced locally when our waste breaks down in the landfill. These emissions are considered local, sector-based emissions. Waste and material reductions from this Plan contribute 1% or 15,000 MT, of the forecast reductions for local sector-based emissions. However, the small scale of the waste and materials strategies do not tell the whole story. The bulk of emissions generated to produce imported goods, food, and services (like air travel) happen outside of Bend's geographic boundaries.

This Plan includes a variety of actions to address these "consumption-based emissions" such as reducing edible food waste, implementing curbside composting and construction and demolition material recycling programs, encouraging the repair and reuse of consumer goods, and increasing community use of low-carbon concrete. These strategies will reduce consumption-based emissions by 90,000 MT CO2e in 2050. It is challenging to set goals around these strategies because it is difficult to accurately track the progress of these strategies within a greenhouse gas inventory, but we think it is important to do so and will continue to work on appropriate tracking mechanisms. Table 4 describes the strategies that the Community will take to reduce emissions from waste and materials.

Figure 11: Bend sector-based emissions with household consumption emissions.



Waste and Materials

Table 4. Waste and Materials - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: W1 - Improve non-food waste recovery*						
W1A – Improve recycling at multifamily residences. Create codes, standards, and specifications to ensure multifamily developments optimize for recycling infrastructure. Conduct outreach and education to improve recycling in multifamily housing. Coordinate with Deschutes County and waste haulers to ensure that the programs developed can be standardized across the region.	Lead: Bend Partners: Deschutes County, Waste Haulers	• Number and percentage of multifamily units served with recycling.	45% non-food material recovery by 2025.	800,000	Not available	
W1B – Develop a recycling and waste reduction program targeting tourists, including hotels and resort communities.	Lead: Community Partners Partners: Tourism Agencies, Businesses	• Number and percentage of organizations participating. • Number of tons and percentage of total waste recovered.				
W1C – Investigate and invest in facility and infrastructure upgrades to meet long term needs of solid waste system. Expand infrastructure to accommodate higher levels of waste recovery.	Lead: Deschutes County, Waste Haulers Partners: Not yet identified	• Dollars invested. • Expected diversion per dollar of capital and expected operations and maintenance.				
STRATEGY*: W2 - Expand use of low-carbon concrete in City projects and new development*						
W2A – Utilize low-carbon concrete mixes in City projects and create incentives to encourage developers to utilize low-carbon concrete.	Lead: Bend Partners: Oregon Department of Environmental Quality	• Number of tons and percentage of tons or square yards of concrete with low-carbon concrete substitute compared to conventional concrete.	30% low-carbon materials used in 50% of community concrete consumption.	240,000	$200 to $0	

City of Bend · Public Agencies · Community Partners · Utility · City and State Partners · Deschutes County · Waste Haulers · Tourism Agencies · Businesses

Savings · Expenditures · Economic Vitality · Affordability · Supports the Natural Environment · Community Health and Safety · Adaptation and Resilience · Social Equity · Oregon Department of Environmental Quality

Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.

Waste and Materials

Table 4. Waste and Materials - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: W3 - Improve food waste recovery*						
W3A – Expand curbside composting program by accepting more materials and increasing participation.	Lead: City of Bend Partners: Community Partners, Deschutes County	• Number of tons of curbside compost collected. • Percentage of total waste recovered as compost per year.	25% food waste recovery by 2025. 50% food waste recovery by 2050.	210,000	$0	Economic Vitality, Affordability, Supports the Natural Environment, Community Health and Safety, Social Equity
W3B – Develop and deliver educational programs that teach and encourage residents to compost their food waste.	Lead: Community Partners, City of Bend Partners: Not yet identified	• Number and percentage of households reached with the message. • Number of times each household has been delivered the message.				
STRATEGY*: W4 - Improve construction and demolition waste recovery*						
W4A – Expand and develop new programs to increase recovery of construction and demolition materials. Identify barriers to recovering materials and use these programs to help overcome these barriers.	Lead: City of Bend, Deschutes County Partners: Not yet identified	• Tons and percentage of construction and demolition waste that is recovered.	Target not identified.	150,000	Not available	Economic Vitality, Affordability, Supports the Natural Environment, Community Health and Safety, Social Equity

City of Bend | Public Agencies | Community Partners | Utility | City and State Partners | Deschutes County | Waste Haulers | Tourism Agencies | Businesses

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity | Oregon Department of Environmental Quality

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Waste and Materials

Table 4. Waste and Materials - Climate Action Strategies

Implementation Actions	Implementation Responsibilities	Progress Metric	Target	Cumulative Emission Reductions Potential* (each circle below represents 200,000 metric tons of emissions)	Savings or Expenditure Range (per metric ton of emissions reduced)	Co-benefits
STRATEGY*: W5 - Develop outreach and education materials for upstream consumption reduction*						
W5A – Conduct outreach campaigns that promote waste prevention and reducing consumption. Connect residents and businesses to local resources like repair cafes that help reduce waste.	Lead: Partners: Not yet identified	• Diverted tons or dollars of resold goods. • Number of attendees at repair fairs.	Target not identified.	100,000	$270	
W5B – Implement training programs for specific industries to prevent waste. Identify these industries based on waste characterization data from the Knott landfill (once available). Examples include the building and construction industry and the food and restaurant industry.	Lead: Partners: Not yet identified	• Number of participants in training programs.				
STRATEGY*: W6 - Develop programs that encourage food waste prevention*						
W6A – Conduct outreach campaigns that promote food waste prevention.	Lead: Partners: Not yet identified	• Quantity of avoided food waste through food donation programs. • Number and percentage of households reached with message. • Number of times each household has been delivered the message.	Reduce edible food waste by 5%.	100,000	$1,200	

City of Bend | Public Agencies | Community Partners | Utility | City and State Partners | Deschutes County | Waste Haulers | Tourism Agencies | Businesses

Savings | Expenditures | Economic Vitality | Affordability | Supports the Natural Environment | Community Health and Safety | Adaptation and Resilience | Social Equity | Oregon Department of Environmental Quality

**Emissions reduction potential assumes stated strategy target is achieved. For more details on methodology and calculations, see Appendix D.*

Equity Actions and Outcomes

The following equity actions will be taken to make strategies and actions in this sector more accessible:

- Engage in intentional outreach campaigns in multiple languages that inform communities not reached by traditional methods about ways they can implement these strategies.
- Encourage multifamily property owners to include space for recycling and composting at new developments either through incentives or requirements.

The strategies and actions in this sector will lead to the following equity outcomes:

- Develop internship and training opportunities in repair and reuse fields to develop workforce skills in these trades.

7. Community Climate Action Plan Implementation

Ongoing oversight and coordination of the Community Climate Action Plan will require a creative and collaborative approach that is different than many other plans overseen by the City of Bend. The City will need to continue to coordinate with the various implementation partners, and continue to engage with residents, businesses and public agencies.

City Staffing for Coordination and Project Management

The City of Bend will provide staff and be accountable for overseeing the coordination of this Plan. This includes coordinating with departments of the City that will be executing certain elements of this Plan, and also with external entities who are key implementation partners. Staff will meet with implementation partners throughout the year to check progress of plan elements, provide technical assistance, and ensure strategies are moving forward. The City will be accountable for ongoing monitoring, tracking and reporting of progress, including coordinating updating the greenhouse gas emissions inventory and this Plan every three to five years.

Community Governance and Coordination

Successfully implementing this Plan requires a collaborative approach to governance and coordination. The City will work with other public agencies and community partners to define a governance structure that facilitates ownership, decision making and strategy execution in partnership with many other entities. The City will be the primary implementer for many strategies in this Plan, but just as many must be implemented by community partners and other public agencies. The governance model for this plan should also create opportunities for key stakeholders, subject matter experts, and members of the public to provide input and recommendations on program and policy development for the strategies, such as through an advisory committee, technical advisory group, or similar.

Funding and Financing this Plan

This Plan will only be successful if the City and community dedicate necessary resources to the initiatives described in the climate action strategies. Funding and financing to implement this Plan fully will need to come from a variety of sources and will include both public and private funds. As programs are developed and funding needs are determined more definitively, the City and the Committee will work together to identify and leverage appropriate grants, public financing mechanisms, private investment and public-private partnerships to fund the climate action strategies. Appendix G maps out potential funding and financing pathways that can be used for each specific strategy.

The City of Bend and the community are committed to climate action for the long term. The strategies in this Plan are meant to be short- to medium-term activities that are actionable and can be initiated or complete in the next three to five years. Each strategy described will require different sets of stakeholders to be engaged to define specific programs, identify resources needed, set action-specific targets, and develop more specific implementation plans with assigned roles and responsibilities. The development of this Plan is the just the beginning of meaningful work to reduce our community's greenhouse gas emissions. This Plan is to be referenced as a living document and updated as the community evolves, technologies improve and understanding progresses about what is needed for meaningful climate action.

Climate Plan Update in Three to Five Years

The City will formally update this Plan in three to five years. The next iteration of this Plan should address the following recommendations:

- **Focus on adaptation strategies and tie into the community's resiliency plans:** This Plan is focused specifically on climate mitigation, or reducing the greenhouse gas emissions from the community. However, communities around the world, including Central Oregon, are already feeling the effects of climate change in the form of extreme weather events, heat, catastrophic wildfires, drought and more. These climate-related impacts are expected to persist and get more intense, and it is vital the community is prepared to handle these events.

The next phase of climate action planning for the Bend community should include adaptation strategies to acknowledge and address how Bend can adapt to future climate-related events, while still working to mitigate future impacts.

- **Greater focus on consumption**: The Bend Community Greenhouse Gas Inventory found that the impact of the goods, food, and fuel we consume that occurs outside of the community boundaries is greater than the emissions that occur within our City. The Climate Action Goals established in Resolution 3044 were centered on fossil fuel use within the City boundaries, so the goals and analysis were completed without including the impact of the consumption-based emissions. With an understanding of how significant the impact is from consumption, the next Plan should focus more on this topic and include consumption emissions in its stated goals.
- **Focus on water conservation and the water-energy nexus:** Water treatment, conveyance, and heating are energy intensive activities that contribute to greenhouse gas emissions. As we live in a high-desert ecosystem, water conservation is extremely important and activities to save water should be an important component of our community's efforts to reduce emissions. Due to focusing on the four primary emission sectors (energy supply, buildings, transportation, waste and materials), this Plan does not explicitly address water use and conservation. The next plan should include strategies that address emissions from water use and encourage water conservation.

Glossary

Term	Definition
Biodigester	A technology in which organic waste material is decomposed by microbial action and typically produces biogas, which can then be used as a renewable fuel or converted to renewable electricity to offset fossil fuel use
Business as usual	A scenario assuming no actions are taken to reduce greenhouse gas emissions
Carbon dioxide equivalent (CO2e)	A measurement that describes how much global warming potential a given type and amount of greenhouse gas may cause using the functionally equivalent amount or concentration of carbon dioxide as the reference
Climate strategy/strategies	The higher-level objective(s) that the community needs to reduce its fossil fuel consumption
Climate action(s)	Specific programs, policies or initiatives that the community can take to make progress in its climate strategy to reduce greenhouse gas emissions
Consumption-based emissions	Emissions from the production of goods, materials and services that are consumed by residents of a certain geographic area but are produced outside of the geographic area. The emissions come from activities such as raw material extraction, production, and transport of materials and goods
Co-benefit	Additional positive benefit from implementing a strategy other than solely greenhouse gas reduction
Climate change adaptation	Actions to adjust to actual or expected climate and its effects, which seek to lower the risks posed by the consequences of climatic changes
Climate change mitigation	Actions to limit the magnitude or rate of climatic changes and their related effects by reducing greenhouse gas emissions
Demand response program	Programs that encourage utility customers to change their power consumption or use of a resource to better match the demand for power with the supply

Glossary

Term	Definition
Energy audit	An assessment and analysis of energy flows for energy conservation in a building. Energy audits help to identify and prioritize possible upgrades to improve energy efficiency in buildings, such as increasing insulation or using different HVAC systems
Energy benchmarking	The practice of comparing the measured energy performance of a facility to itself, other facilities or established norms, with the goal of informing or motivating improved performance
Emission intensity	The emission rate of a given pollutant relative to the intensity of a specific activity
Equity action	Specific programs, policies or initiatives that make the climate actions more accessible and/or less harmful to underserved community members and increase benefits to traditionally underserved populations
Equity outcome	A resulting effect that supports equity through increasing benefits or mitigating harmful impacts to traditionally underserved populations or by making programs more accessible to underserved populations
Fossil fuel	Fuel formed from the remains of living organisms through natural processes that occur in the earth
Greenhouse gas	Gas that traps heat in the atmosphere by absorbing infrared radiation
Greenhouse gas emissions inventory	A study that quantifies the greenhouse gas emissions that are generated within a specific boundary. The boundary can be geographic, such as the City of Bend, or it can be defined by operational or financial control
Location-based emissions	Emissions calculated using the regional electricity grid greenhouse gas intensity. These represent the average impacts of electricity use and efficiency efforts across a large geographic area
Market-based emissions	Emissions calculated using the greenhouse gas intensity of electricity contracts with local utilities

Glossary

Term	Definition
Metric ton (MT)	A unit used to measure greenhouse gas emissions, equal to 1,000 kilograms or approximately 2,204.6 pounds
Microgrid	A small network of electricity users with a local source of supply that is usually attached to a centralized grid but can function independently
Revolving loan fund	A self-replenishing pool of money that utilizes interest and principal payments on old loans to issue new ones
Sector-based emissions	Emissions that come from sources located within a geographic boundary and emissions that occur as a consequence of the use of grid-supplied energy within the geographic boundary
Technical potential	The maximum achievable emissions reduction of a specific strategy or action
Triple bottom line	A framework that assesses actions with a three-part lens that includes environmental, social and economic impacts

Composite Exhibit 4

Down the Line Compressor Stations

TC Energy Tariff Map of GTN Compressor Stations

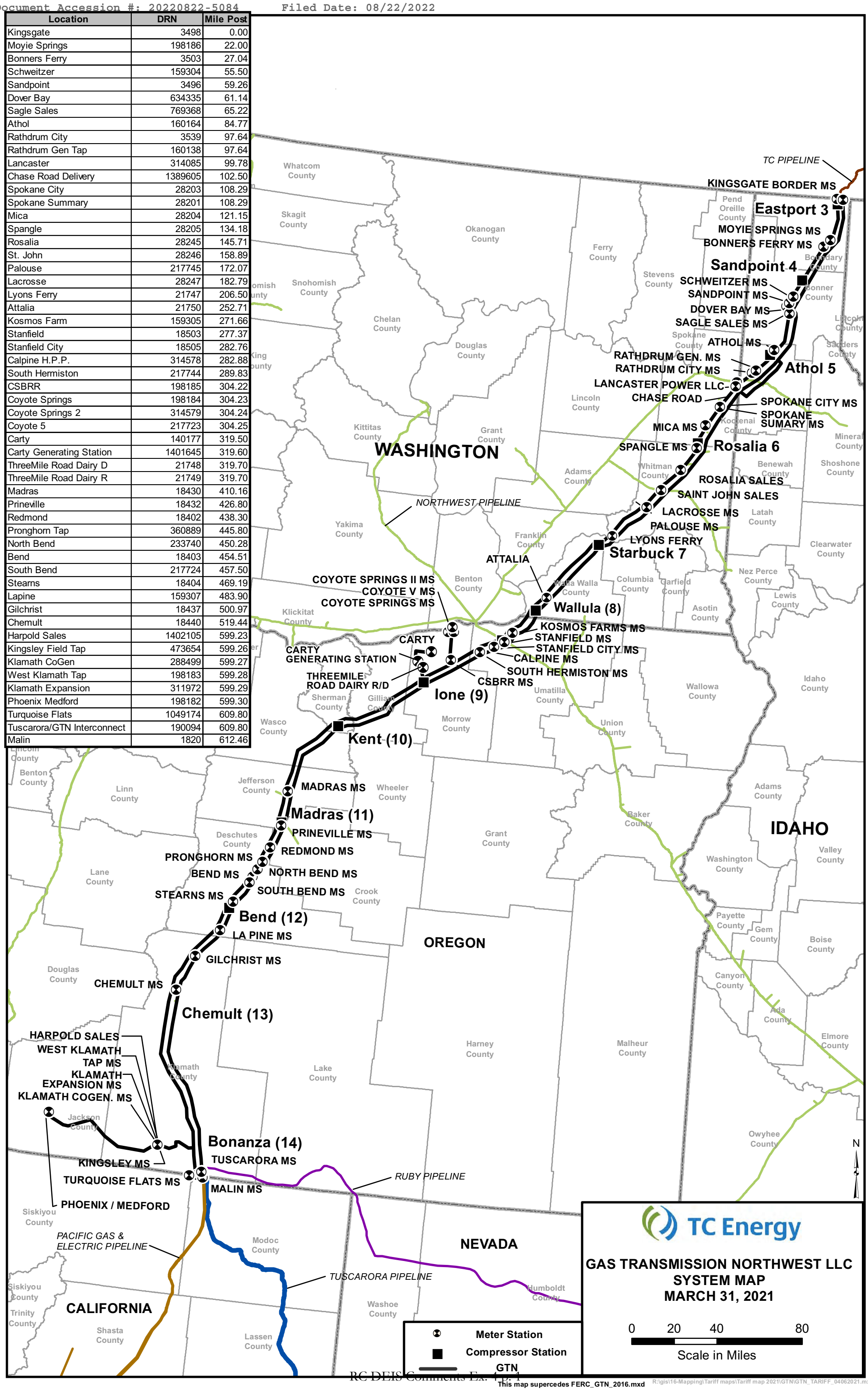
Bend Station Haze Program Compliance Letter

Bend Station Stipulated Agreement and Final Order

Chemult Station Haze Program Compliance Letter

Chemult Station Final Order

Location	DRN	Mile Post
Kingsgate	3498	0.00
Moyie Springs	198186	22.00
Bonners Ferry	3503	27.04
Schweitzer	159304	55.50
Sandpoint	3496	59.26
Dover Bay	634335	61.14
Sagle Sales	769368	65.22
Athol	160164	84.77
Rathdrum City	3539	97.64
Rathdrum Gen Tap	160138	97.64
Lancaster	314085	99.78
Chase Road Delivery	1389605	102.50
Spokane City	28203	108.29
Spokane Summary	28201	108.29
Mica	28204	121.15
Spangle	28205	134.18
Rosalia	28245	145.71
St. John	28246	158.89
Palouse	217745	172.07
Lacrosse	28247	182.79
Lyons Ferry	21747	206.50
Attalia	21750	252.71
Kosmos Farm	159305	271.66
Stanfield	18503	277.37
Stanfield City	18505	282.76
Calpine H.P.P.	314578	282.88
South Hermiston	217744	289.83
CSBRR	198185	304.22
Coyote Springs	198184	304.23
Coyote Springs 2	314579	304.24
Coyote 5	217723	304.25
Carty	140177	319.50
Carty Generating Station	1401645	319.60
ThreeMile Road Dairy D	21748	319.70
ThreeMile Road Dairy R	21749	319.70
Madras	18430	410.16
Prineville	18432	426.80
Redmond	18402	438.30
Pronghorn Tap	360889	445.80
North Bend	233740	450.28
Bend	18403	454.51
South Bend	217724	457.50
Stearns	18404	469.19
Lapine	159307	483.90
Gilchrist	18437	500.97
Chemult	18440	519.44
Harpold Sales	1402105	599.23
Kingsley Field Tap	473654	599.26
Klamath CoGen	288499	599.27
West Klamath Tap	198183	599.28
Klamath Expansion	311972	599.29
Phoenix Medford	198182	599.30
Turquoise Flats	1049174	609.80
Tuscarora/GTN Interconnect	190094	609.80
Malin	1820	612.46



Oregon

Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
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TTY 711

January 21, 2021

Melinda Holdsworth
melinda_holdsworth@tcenergy.com
TC Energy
700 Louisiana St, Ste 700
Houston, TX 77002-2873

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost Effective Controls; Gas Transmission Northwest Compressor Station 12, 09-0084

Dear Melinda Holdsworth:

Thank you for your responses to Department of Environmental Quality's (DEQ) December 23, 2019 request for four factor analysis for your facility, and DEQ's request for additional information on August 14, 2020, as DEQ gathered information on how to fulfill Round 2 of the Regional Haze Program in Oregon.

Based on the information provided in the four factor analysis, the cost information that you submitted, the additional information you provided, and the process DEQ is proposing to use to screen facilities, DEQ estimates the following controls are likely to be required at your facility:

Emissions Unit	Control Device	Target Pollutant
12A	SCR	NOx
12B	SCR	NOx

DEQ intends to proceed with a rulemaking that adopts the process for this analysis. If DEQ's proposed rules are approved by the Environmental Quality Commission, DEQ will likely require your facility to install these controls.

If you disagree with, or would like to discuss DEQ's preliminary determination as outlined in this letter, we encourage you to reach out to the DEQ now. After DEQ adopts rules, it intends to impose Round 2 regional haze requirements promptly thereafter and without additional discussion to meet federal timelines for submission of the State Implementation Plan.

DEQ appreciates your commitment to protecting air quality and improving visibility in Oregon's Class 1 Areas. If you have any questions about the content of this letter or need technical assistance, please contact Michael Orman, at michael.orman@deq.state.or.us or 503-509-8623.

Sincerely,

Ali Mirzakhalili
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
Joe Westersund
Michael Orman
Walt West

BEFORE THE DEPARTMENT OF ENVIRONMENTAL QUALITY

OF THE STATE OF OREGON

IN THE MATTER OF Gas Transmission Northwest LLC Compressor Station #12 Permittee.	)))))	STIPULATED AGREEMENT AND FINAL ORDER ORDER NO. 09-0084

Permittee, Gas Transmission Northwest LLC, and the Department of Environmental Quality (DEQ) hereby agree that:

WHEREAS:

1. Permittee operates a natural gas compressor station located at US Highway 97, 19 miles south of Bend in Bend, Oregon (the Facility).

2. On July 9, 1996, DEQ issued Title V Operating Permit No. 09-0084-TV-01 (the Permit) to Permittee.

3. On August 10, 2017, DEQ renewed the Permit.

4. The Permit authorizes Permittee to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. As of December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, *see* OAR 340-223-0020(2) at the Facility: 39 tons per year for SO2, 14 tons per year for PM 10, and 377 tons per year for NOx.

6. The Facility is located 30.4 kilometers from the Three Sisters Wilderness Area, which is the nearest Class I Area, *see* OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

7. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 430; d value is 30.4, and ratio of Q divided by d is 14.1.

8. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

9. Rather than complying with OAR 340-223-0110(1), the Facility would like to enter into a Stipulated Agreement with DEQ for alternative compliance with round II of regional haze and would like to accept federally enforceable reductions of combined plant site emission limits of round II regional haze pollutants to bring the Facility's Q/d below 5.00 which DEQ shall incorporate into a Final Order. *See* OAR 340-223-0110(2)(b)(A).

I. AGREEMENT

1. DEQ issues this Stipulated Agreement and Final Order (SAFO) pursuant to OAR 340-223-0110(2)(b)(A), and it shall be effective upon the date fully executed.

2. The Facility is subject to round II of regional haze, according to OAR 340-223-0100(1).

3. The Permittee agrees to and will ensure compliance with the PSEL reductions schedule in Section II of this SAFO.

4. The PSEL reductions required by this SAFO shall not be banked, credited, or otherwise accessed by Permittee for use in future permitting actions.

5. PSELs for this Facility shall not exceed the limits established in this SAFO except as approved in accordance with applicable state and federal permitting regulations.

6. The Permittee shall calculate compliance with the PSELs in Section II of this SAFO according to the requirements of the Permit.

7. DEQ shall incorporate this SAFO and the conditions in Section II below into the Permit pursuant to 340-218-0200(1)(a)(A), if applicable, or upon permit renewal.

8. DEQ may submit this SAFO to the Environmental Protection Agency as part of the State Implementation Plan under the federal Clean Air Act.

9. Permittee waives any and all rights and objections Permittee may have to the form, content, manner of service, and timeliness of this SAFO and to a contested case hearing and judicial

review of the SAFO.

10. In the event EPA does not accept DEQ's Round II Regional Haze State Implementation Plan (SIP) in any manner that impacts the final order, implementation of the Final Order shall be stayed until DEQ and the Permittee shall negotiate modifications to the Final Order in such a manner as to ensure compliance with the Round II Regional Haze SIP.

11. This SAFO shall be binding on Permittee and its respective successors, agents, and assigns. The undersigned representative of Permittee certifies that he, she, or they are fully authorized to execute and bind Permittee to this SAFO. No change in ownership, corporate, or partnership status of Permittee, or change in the ownership of the properties or businesses affected by this SAFO shall in any way alter Permittee's obligation under this SAFO, unless otherwise approved in writing by DEQ through an amendment to this SAFO.

12. If any event occurs that is beyond Permittee's reasonable control and that causes a deviation in performance of the requirements of this SAFO, Permittee must notify DEQ as soon as possible via email and follow up with a phone call providing verbally the cause of delay or deviation and its anticipated duration, the measures that Permittee has or will take to prevent or minimize the delay or deviation, and the timetable by which Permittee proposes to carry out such measures. Permittee shall confirm in writing this information within five (5) business days of the onset of the event. It is Permittee's responsibility in the written notification to demonstrate that the delay or deviation has been caused by circumstances beyond the control and despite due diligence of Permittee. If Permittee so demonstrates, DEQ may extend times of performance of related activities under this SAFO as appropriate. Circumstances or events beyond Permittee's control include, but are not limited to, extreme and unforeseen acts of nature, unforeseen strikes, work stoppages, fires, explosion, riot, sabotage, or war. Increased cost of performance or a consultant's failure to provide timely reports are not considered circumstances beyond Permittee's control.

13. Facsimile or scanned signatures on this SAFO shall be treated the same as original signatures.

II. FINAL ORDER

The DEQ hereby enters a final order requiring Permittee to comply with the following schedule and conditions:

1. The Permittee shall comply with the PSELs according to the following schedule:
   a. On August 1, 2022, the Permittee's PSELs for the following pollutants are:
      i. 12.7 tons per year for PM10; 317.1 tons per year for NOx; and 30.4 tons per year for SO2.
   b. On August 1, 2023, the Permittee's PSELs for the following pollutants are:
      i. 11.4 tons per year for PM10; 257.2 tons per year for NOx; and 21.7 tons per year for SO2.
   c. On August 1, 2024, the Permittee's PSELs for the following pollutants are:
      i. 10.2 tons per year for PM10; 197.3 tons per year for NOx; and 13.1 tons per year for SO2.
   d. On August 1, 2025, the Permittee's PSELs for the following pollutants are:
      i. 8.9 tons per year for PM10; 137.4 tons per year for NOx; and 4.4 tons per year for SO2.

GAS TRANSMISSION NORTHWEST LLC
(PERMITTEE)

August 9, 2021
Date

By: DocuSigned by: John McWilliams 05C8C56BD85546D...
John J. McWilliams, Vice-President

By: DocuSigned by: Emily Strait 7BE179CD86EB4C0...
Emily L. Strait, Assistant Secretary

DS JH

DEPARTMENT OF ENVIRONMENTAL QUALITY and
ENVIRONMENTAL QUALITY COMMISSION

August 9, 2021
Date

DocuSigned by: Ali Mirzakhalili 7895034861B1468...
Ali Mirzakhalili, Administrator
Air Quality Division
on behalf of DEQ pursuant to OAR 340-223-0110(2)

Oregon
Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
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(503) 229-5696
FAX (503) 229-6124
TTY 711

January 21, 2021

Melinda Holdsworth
melinda_holdsworth@tcenergy.com
TC Energy
700 Louisiana St Ste 700
Houston, TX 77002-2873

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost Effective Controls; Gas Transmission NW LLC - Compressor Station #13, 18-0096

Dear Melinda Holdsworth:

Thank you for your responses to Department of Environmental Quality's (DEQ) December 23, 2019 request for four factor analysis for your facility, and DEQ's request for additional information on August 14, 2020, as DEQ gathered information on how to fulfill Round 2 of the Regional Haze Program in Oregon.

Based on the information provided in the four factor analysis, the cost information that you submitted, the additional information you provided, and the process DEQ is proposing to use to screen facilities, DEQ estimates the following controls are likely to be required at your facility:

Emissions Unit	Control Device	Target Pollutant
13C	SCR	NOx
13D	SCR	NOx

DEQ intends to proceed with a rulemaking that adopts the process for this analysis. If DEQ's proposed rules are approved by the Environmental Quality Commission, DEQ will likely require your facility to install these controls.

If you disagree with, or would like to discuss DEQ's preliminary determination as outlined in this letter, we encourage you to reach out to the DEQ now. After DEQ adopts rules, it intends to impose Round 2 regional haze requirements promptly thereafter and without additional discussion to meet federal timelines for submission of the State Implementation Plan.

DEQ appreciates your commitment to protecting air quality and improving visibility in Oregon's Class 1 Areas. If you have any questions about the content of this letter or need technical assistance, please contact Michael Orman, at michael.orman@deq.state.or.us or 503-509-8623.

Sincerely,

Ali Mirzakhalili
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
Joe Westersund
Michael Orman
Walt West
Mark Bailey

BEFORE THE ENVIRONMENTAL QUALITY COMMISSION

OF THE STATE OF OREGON

IN THE MATTER OF: Gas Transmission Northwest LLC Compressor Station #13	)))	FINAL ORDER TO REQUIRE COMPLIANCE WITH ROUND II OF REGIONAL HAZE
Respondent.	)	CASE NO. AQ/RH-HQ-2021-140

I. AUTHORITY

The Department of Environmental Quality (DEQ) issues this Final Order (Notice) pursuant to Oregon Revised Statutes (ORS) 468A.025, and Oregon Administrative Rules (OAR) Chapter 340, Divisions 011 and 223.

II. FINDINGS OF FACT

1. Respondent, Gas Transmission Northwest LLC, operates a natural gas compressor station located at 1/4 mile west of Diamond Lake Junction in Chemult, Oregon (the Facility).

2. On April 9, 1996, DEQ issued Title V Operating Permit No. 18-0096-TV-01 (the Permit) to Respondent.

3. On July 11, 2018, DEQ renewed the Permit.

4. The Permit authorizes Respondent to discharge air contaminants associated with its operation of the Facility in conformance with the requirements, limitations, and conditions set forth in the Permit.

5. Turbines 13C and 13D at the Facility are emission units, as defined in OAR 340-223-0020(1).

6. On December 31, 2017, the Permit had the following plant site emissions limit (PSEL) for sulfur dioxide (SO2), particulate matter of ten microns or less (PM10), and nitrogen oxides (NOx), which constitute round II regional haze pollutants, see OAR 340-223-0020(2), at the Facility: 39 tons per year for SO2, 14 tons per year for PM 10, and 244 tons per year for NOx.

7. The Facility is located 30.4 kilometers from the Three Sisters Wilderness Area, which is the nearest Class I Area, see OAR 340-200-0020(25), measured in a straight line from the Facility to the Class I Area.

8. On December 31, 2019, DEQ sent a request for information request to Respondent, pursuant to OAR 340-214-0110, to complete a Four Factor Analysis (FFA) for round II of regional haze.

9. On May 12, 2020, Respondent submitted a FFA to DEQ, identifying the cost of controls for the Facility to reduce round II regional haze pollutants.

10. On August 14, 2020, DEQ requested additional information from Respondent regarding their FFA submittal.

11. On January 21, 2021, DEQ concurred with Respondent's findings in the May 12, 2020 FFA that control of NOx by Selective Catalytic Reduction (SCR) is cost effective for Turbines 13C and 13D at the Facility.

12. On August 3, 2021, Respondent submitted a final control cost calculation. DEQ adjusted the calculations pursuant to OAR 340-223-0120(2), OAR 340-223-0120(3) and OAR 340-223-0120(4), which showed that control of NOx by Selective Catalytic Reduction (SCR) is cost effective for Turbines 13C and 13D at the Facility. The final cost calculation is attached as Exhibit A and is incorporated as part of this Order.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Based on the definitions and the formula in OAR 340-223-0100(2) the Facility's Q value is 277; d value is 14.1, and ratio of Q divided by d is 19.68.

2. Because the Facility has a Title V operating permit and because the Facility has a Q/d value of greater than 5.00, the Facility is subject to the requirements of round II of regional haze. *See* OAR 340-223-0100(1).

3. As of the date of this Order, DEQ and Respondent have not entered into a stipulated agreement and final order under OAR 340-223-0110(2).

4. After review and consideration of all the data submitted by the Facility and based on adjustments by DEQ to Respondent's FFA pursuant to OAR 340-223-0120(2) and (3), DEQ has determined that the Respondent identified control devices that would reduce round II regional haze pollutants with a cost effectiveness below the cost threshold identified in OAR 340-223-0120(4)(a).

IV. ORDER REQUIRING COMPLIANCE WITH ROUND II OF REGIONAL HAZE

Based upon the foregoing FINDINGS OF FACT AND CONCLUSIONS OF LAW, and pursuant to OAR 340-223-0130(1), Respondent is hereby ORDERED TO:

1. By July 31, 2023, Respondent shall submit to DEQ a complete and approvable permit application to incorporate appropriate and required permit conditions for the installation and operation of Selective Catalytic Reduction (SCR) and Continuous Emissions Monitoring System (CEMS) on Turbines 13C and 13D.

2. By July 31, 2024, install a CEMS on Turbines 13C and 13D to measure the emissions of NOx.

   a. Respondent shall demonstrate proper installation of the CEMS following EPA Procedure 1 (see 40 CFR 60, Appendix F, Procedure 1),), Performance Specification 2 (see 40 CFR 60, Appendix B, Performance Specification 2), and DEQ Continuous Monitoring Manual, Rev. 2015; and

   b. Respondent shall submit data collected during testing identified in Section IV.1.a of this Final Order to DEQ for review and to determine if the CEMS was installed correctly and meets the identified quality assurance criteria.

3. By July 31, 2026, install, maintain, and continuously operate SCR on Turbines 13C and 13D with a minimum control efficiency of 90%.

4. Respondent shall not operate Turbines 13C and 13D after August 1, 2026, unless the SCR is properly operating.

V. NOTICE OF RIGHT TO REQUEST A CONTESTED CASE HEARING

You have a right to a contested case hearing on this Order, if you request one in writing. DEQ must receive your request for hearing **within 10 calendar days** from the date you receive this Order. If you have any affirmative defenses or wish to dispute any allegations of fact in this Order, you must do so in your request for hearing, as factual matters not denied will be considered admitted, and failure to raise a defense will be a waiver of the defense. (See OAR 340-011-0530 for further information about requests for hearing.) You must send your request to: **DEQ, Office of Compliance and Enforcement, 700 NE Multnomah Street, Suite 600, Portland, Oregon 97232**, fax it to **503-229-6762** or email it to **DEQappeals@deq.state.or.us**. An administrative law judge employed by the Office of Administrative

Hearings will conduct the hearing, according to ORS Chapter 183, OAR Chapter 340, Division 011 and OAR 137-003-0501 to 0700. You have a right to be represented by an attorney at the hearing, however you are not required to be. If you are an individual, you may represent yourself. If you are a corporation, partnership, limited liability company, unincorporated association, trust or government body, you must be represented by an attorney or a duly authorized representative, as set forth in OAR 137-003-0555.

Active duty Service members have a right to stay proceedings under the federal Service Members Civil Relief Act. For more information contact the Oregon State Bar at 1-800-452-8260, the Oregon Military Department at 503-584-3571, or the nearest United States Armed Forces Legal Assistance Office through http://legalassistance.law.af.mil. The Oregon Military Department does not have a toll free telephone number.

If you fail to file a timely request for hearing, the Order will become a final order by default without further action by DEQ, as per OAR 340-011-0535(1). If you do request a hearing but later withdraw your request, fail to attend the hearing or notify DEQ that you will not be attending the hearing, DEQ will issue a final order by default pursuant to OAR 340-011-0535(3). DEQ designates the relevant portions of its files, including information submitted by you, as the record for purposes of proving a prima facie case.

8/9/2021
Date

Ali Mirzakhalili, Air Quality Administrator
Oregon Department of Environmental Quality

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