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June 14, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

Re: LC 71 - NW Natural's 2018 Integrated Resource Plan Update - Reply Comments

Northwest Natural Gas Company, dba NW Natural (NW Natural or Company), files herewith its Reply Comments on NW Natural's 2018 Integrated Resource Plan Update filed on March 1, 2021.

Please address correspondence on this matter to me with copies to the following:

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Sincerely,

/s/ Rebecca T. Brown

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THIRD UPDATE TO NW NATURAL'S 2018 INTEGRATED RESOURCE PLAN

OPUC DOCKET LC 71

NW NATURAL'S REPLY COMMENTS

1. INTRODUCTION

Northwest Natural Gas Company (NW Natural or the Company) files these Reply Comments in response to the Opening Comments submitted in this docket by the Public Utility Commission of Oregon (OPUC), Staff, the Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB).

Prior to addressing specific comments, NW Natural would like to thank all participants in its Integrated Resource Planning (IRP) process for their engagement, comments, and general spirit of collaboration.

NW Natural's Reply Comments are organized generally along the same lines as Staff's Comments.

2. NEWPORT COLD BOX

NW Natural appreciates the thoughtful comments of stakeholders in regards to the Cold Box replacement at the Company's Newport LNG facility. Staff recommends acknowledging replacing the Cold Box at the Newport storage facility. CUB likewise states support for the Commission to acknowledge the replacement of the Newport Cold Box.[1] They also are recommending that the Company establish a prohibition on new alternative supply side resources in seismically vulnerable areas.[2]

NW Natural currently considers – and will continue to consider – with thorough risk analysis, the risks associated with siting new alternative supply side resources in seismically vulnerable areas (noting again that the Newport facility was sited and built more than 50 years ago). These considerations will take into account any specific local, state, and/or federal jurisdictional codes, as well as any applicable standards and best practices, which have also evolved as seismic risks have become better understood. While the siting of these new resources in seismically vulnerable areas is not desirable by NW Natural, there may not be other viable options available in some circumstances, and there are options in designing facilities that can help manage risk. Each future project will be evaluated on a case by case basis and take all risks and management strategies into consideration.

3. DISTRIBUTION SYSTEM PLANNING AND THE NORTH COAST FEEDER UPRATE PROJECT

OPUC Staff supports acknowledging uprating the North Coast Feeder, stating that "*ongoing replacement of infrastructure for safety purposes is part of the Company's basic obligation to provide safe and reliable service*"[3] and recognized the data and modeling verification process

[1] See CUB Comments for LC-71 IRP Update #3, page 3
[2] See CUB comments for LC-71 IRP Update #3, pages 3-4
[3] See Staff comments for LC-71 IRP Update #3, page 6

that has been implemented following helpful stakeholder engagement and Commission direction from the Company's 2018 IRP.

CUB is seeking additional information in these comments in response to questions in their comments and did not recommend acknowledgement of the North Coast Feeder Uprate as this additional information is sought. CUB's requests regarding the North Coast Feeder Uprate project focus on two issues:

1. A question of whether existing equipment (specifically the Walluski regulator) can address the issue without requiring the uprate; and
2. Further exploration of whether non-pipeline solutions in the area are a feasible option to delay or avoid the uprate

Regarding the Walluski regulator, CUB asks whether it can be set at a higher-pressure level and bring the pressure drop expected during cold weather conditions to within NW Natural's distribution system planning criteria limits (i.e. reduce the pressure drop to less than 40% of maximum).[4] This is a valid question, and the short answer is "no," the Walluski regulator cannot be legally set to a pressure set point that would alleviate the need for a reinforcement project (like the North Coast Feeder Uprate).

NW Natural analyzed setting the Walluski regulator at higher pressure set points as CUB has suggested in their comments, but this option was determined not to be sufficient to be able to improve conditions in the area enough such that NW Natural's planning criteria would not remain violated, triggering the need for further action. The set points considered were 170 and 175 psig, based on NW Natural's Engineering Procedure D-10 - Regulator and Relief Set Point Requirements (see attachment A). The 170 psig set point is the highest setting allowable by NW Natural's Engineering Procedure D-10 without a crew on-site to monitor the over pressure protection of the relief valve. The 175 psig set point is the highest allowable setting possible, but would require a crew on-site to monitor the over pressure protection of the relief valve during cold events. In general, NW Natural does not adjust the regulator set points to these higher levels because of the build-up pressure that may occur and cause the overpressure protection relief valve to activate. If this situation occurs, a NW Natural crew must be immediately dispatched to the site to respond. Therefore, the set points of the regulator are typically adjusted to provide an optimized balance between maximum pressure possible and a risk evaluation of activating the off-pressure protection relief valve.

As is described in NW Natural's 2018 IRP Update #3, the system modeling in the area has been validated and calibrated to actual conditions using on-site pressure recording. Using this calibrated modeling, and modeling the same weather conditions that were experienced on November 30^{th,} 2019,[5] which is meaningfully warmer than peak planning conditions, the results show that the North Coast Pipeline would have experienced a pressure drop that is greater than 40% at the inlet of the Cannon Beach Regulator station at either 170 or 175 psig, as can be

[4] See CUB comments for LC-71 IRP Update #3, pages 4-5
[5] On November 30, 2019 it was 32.5°F at 9:00am.

seen in Table 1: Set Point Comparison at 32.5°F below. Further, a dataset extracted from an electronic portable pressure recorder (EPPR) installed in the area recorded a pressure drop in this area of the system that exceeded 40% on January 23rd, 2021. Therefore, per NW Natural's Engineering Procedure D-15 - System Reinforcement Standards (see attachment B), action must be taken to address this reliability issue because adjusting the Walluski regulatory set point is not sufficient. Note that all pressure drops in Table 1 would be larger under actual peak planning weather conditions rather than the conditions experienced over the last couple of heating seasons.

Table 1: Set Point Comparison at 32.5°F

Set Point (psig)	Cannon Beach Inlet (psig)	Pressure Drop
170	94.19	44.59%
175	102.56	41.39%

Non-pipeline Solutions and Demand Response

In regards to CUB's comments about energy efficiency, demand response, and the potential for non-pipeline solutions more generally to be used to delay or avoid the North Coast Feeder Uprate project: NW Natural appreciates CUB's comments and is committed to continuing to be a leader in non-pipeline solutions and looks forward to implementing new non-pipeline options moving forward in time. However, in regards to its applicability for the North Coast Feeder project, NW Natural maintains that it is inappropriate to use or wait for the development of options with uncertain impact, costs, and timelines to address current distribution system constraints, as this carries too great a risk to NW Natural customers and is in violation of the Company's obligation to provide safe and reliable service. NW Natural reiterates that there is a current need for a project in the area – as demonstrated in the IRP Update #3 – and it is expected that there would be outages during an extreme weather event if action is not taken. Given this, it is our position that it is inappropriate to attempt to alleviate this issue with actions that are currently being studied in a pilot project that does not yet have results (geographically targeted energy efficiency or GeoTEE), will be studied in detail in NW Natural's next IRP (geographically targeted demand response or GeoDR), or require a source of gas to be sited in the area with a type of project that has not been undertaken to date (siting on-system RNG or Hydrogen in order to alleviate a distribution system constraint). As NW Natural has described in its IRPs and IRP updates, the Company is committed to all of these options going forward and looks forward to working with stakeholders in bringing these activities into the fold for future projects that carry a reasonable level of risk for maintaining reliable service in the near and longer term.

Specifically regarding the Company's ongoing GeoTEE pilot program with Energy Trust of Oregon[6] (the first of its kind in the United States), the ability of Energy Trust to develop peak savings and cost estimates for specific areas of NW Natural's system using the actions CUB

[6] See NW Natural 2018 IRP Update, dated April 17, 2019 as filed in Docket LC 71, Attachments 1 and 2 for program descriptions.

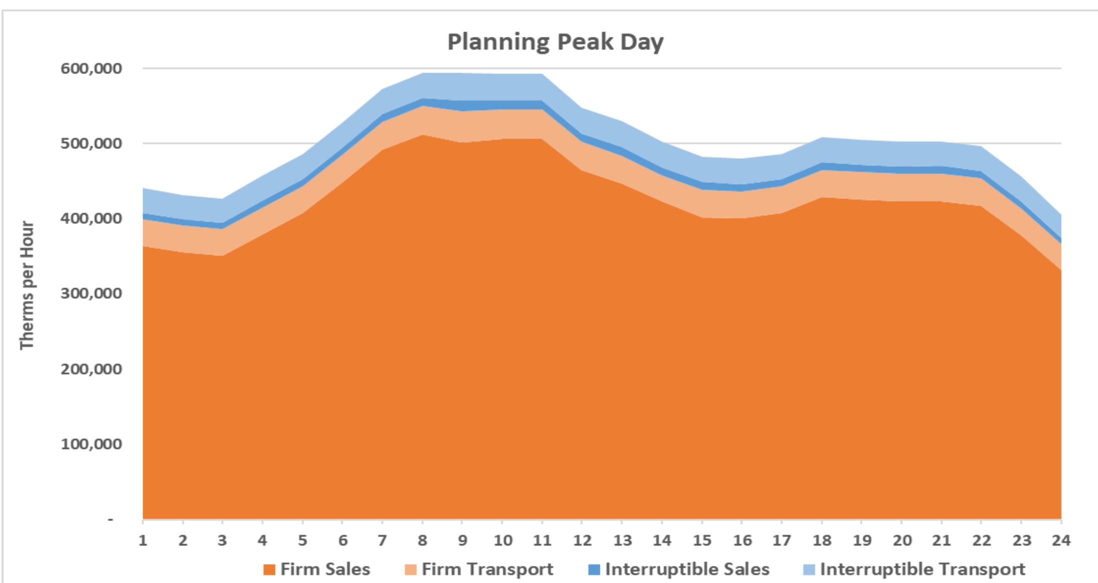
suggests in their comments (higher efficiency heating equipment, smart thermostats, and building shell improvements) is one of the primary goals of the pilot, as is understanding the level of certainty associated with these peak load savings and cost estimates. If GeoTEE appears that it can be cost-effective in some situations and is in the interest of customers more generally (another primary research question of the pilot project), NW Natural plans to work with Energy Trust to implement GeoTEE as an option for distribution system planning going forward.

In regards to demand response, NW Natural looks forward to its third party consultant presenting a detailed demand response potential study as part of the full IRP next year. The Company has been having discussions with vendors of smart equipment to understand the possibilities for natural gas utilities, and anticipates having action items to add incremental demand response programs that primarily target residential and commercial customers. It is also important to understand that NW Natural currently operates the largest demand response program(s) of any utility in Oregon by a wide margin through the Company's interruptible schedules. NW Natural has employed successful and cost-effective interruptible schedules for decades, and this demand response capability has delayed or avoided – and continues to delay and avoid – numerous potential projects. The scope of NW Natural's demand response programs are shown in Table 2 and Figure 1 below:

Table 2 - Demand Response on NW Natural's System

Current NW Natural Demand Response via Interruptible Schedules				
		1-in-2 Peak	1-in-10 Peak	1-in-30 Peak
Interruptible Share of Throughput	Peak Hour	10.7%	9.9%	8.8%
	Peak Day	11.3%	10.4%	8.7%
Interruptible Share of Sales	Peak Hour	3.4%	3.4%	2.9%
	Peak Day	3.1%	2.9%	2.4%

Figure 1 - Demand Response on NW Natural's System- Hourly System Peak Day Load Profile



Note that 8.8% of NW Natural's would-be peak hour deliveries are netted out of loads when the company analyzes the needs of its distribution system under peak conditions, a figure that represents roughly 52,000 therms on a peak hour, which is equivalent to roughly 1,500 MW of demand response in energy equivalency.[7] While NW Natural has shown its peak load forecasts net of demand response in recent IRPs,[8] in the future NW Natural intends to show its loads inclusive of demand response to show the importance of interruptible customers to system planning.

Interruptible customers choose to be interruptible due to the lower costs of interruptible service; a less costly service than firm customers reflecting the ability of the utility to call upon these customers for demand response when needed. In other words, costs are paid by firm customers for the ability to interrupt these interruptible customers at a lower cost than additional gas supply. With the understanding that interruptible tarriffs are cost-effective demand response for the system, it is also fitting to respond to AWEC's request in its comments:

> *NW Natural supplement the 2018 IRP with a special analysis of how its system performed during the days immediately following the rupture on the Enbridge Pipeline, which resulted in the loss of deliveries at Sumas. The analysis should include an in-depth analysis of how curtailments of industrial loads kept NW Natural's system from losing pressure or having to interrupt core customers. The analysis should also include a scenario where this type of event happened in winter, where it would not have been possible to interrupt natural gas fired electric generation, including the effect on both gas and electric service. AWEC continues to believe this analysis would be beneficial and provide valuable guidance into how to manage and mitigate the impacts of major disruptions in the future.*[9]

As NW Natural presented at a public workshop, during the events following the Enbridge Pipeline rupture it may not have been possible to acquire all the gas firm customers demanded without calling a demand response event by interrupting interruptible customers. NW Natural exercised this option to ensure firm service (i.e. pressure) could be maintained during the period of interrupted upstream supply. Given that interruptible loads are netted out of the Company's peak analysis as decribed above, all peak analyses completed by NW Natural include detailed analyses of how interruptible loads help ensure system reliability. If there *were* an extreme cold event during this period it may not have been possible to serve all firm customers, as the Company may not have been able to utilize all of its interstate pipeline capacity to deliver gas to customers. NW Natural does not necessarily feel it is appropriate to assume all gas supply resources are 100% reliable as is currently assumed in the Company's peak analyses, noting that forced outages are considered in reliability analyses completed in electric IRPs in Oregon.

[7] For reference Portland General Electric had 45MW of summer demand response in 2019 and a goal of reaching 211 MW in 2025, representing roughly 1% and 7% of peak load respectively. See PGE's most recent IRP Update at https://edocs.puc.state.or.us/efdocs/HAH/lc73hah13049.pdf

[8] i.e., has not shown the load from customers on interruptible schedules since a key aspect of NW Natural system planning is assuming that a demand response event is called during peak events and interruptible customers will not contribute load to the system

[9] See AWEC comments for LC-71 IRP Update #3, pages 1-2

NW Natural raised this issue during its Technical Working Groups in the 2014 IRP and stakeholders were clear at that time that the current assumption did not need to be changed. NW Natural maintains this assumption should be revisited, especially in light of the Enbridge events from a couple of years ago, California blackouts last year, Oregon blackouts this year, and the issues experienced by the energy system in the central part of the continent (most acutely in Texas) this past winter.

On this topic, NW Natural would also like to reiterate previous reply comments to AWEC, filed during rounds of comments for the 2018 IRP regarding what is advisable to analyze within NW Natural's IRP:

> *The interruption of industrial customers on interruptible service agreements, along with the voluntary actions of regional electric generators to interrupt their natural gas usage, were indeed two of the key steps in helping to avoid potential large-scale outages of firm customers during the period that began on the evening of October 9 and ended on the morning of October 11, 2018. Unfortunately, the analysis that AWEC has requested goes well beyond the scope of NW Natural's IRP. For example, AWEC asks that the analysis include the effects on electric service, which is clearly outside NW Natural's expertise. Also, the impacts of the Enbridge event have been felt by numerous utilities, pipelines and direct connect customers well outside NW Natural's service territory. Accordingly, any analysis would be woefully incomplete if it did not consider the broader regional impacts since gas service has some similarities to the electric grid in that a resource deficiency in one area will eventually lead to deficiencies in other areas if not alleviated in time.*[10]

NW Natural supports the OPUC beginning a process to investigate regional resource adequacy across the natural gas and electric systems and would actively participate in such a process, noting it is critical to the state's resource adequacy to recognize that the direct use natural gas system delivers far more energy to Oregonians during the state's electric system's peak than the electric system itself. However, NW Natural believes this work should be done via a multi-party process rather than as part of any single utility's IRP.

Returning to how these issues manifest in analyzing specific distribution system constraints, the impact of existing DR through interruptible schedules should not be understated or forgotten in the conversation as we continue to engage around the incremental options for demand response that are discussed in the Company's most recent IRP and in CUB's comments. Additionally, it is important to note that the Company has implemented a policy over many years that investigates the viability of targeted *incremental* interruptibility agreements in constrained areas of the distribution system by evaluating the possibility of approaching existing firm industrial loads in the area about the possibility of converting them to interruptible service. However, the area of NW Natural's system affected by the North Coast Feeder has very few large industrial *firm* loads, and analysis showed insufficient opportunity for targeted interruptible schedule agreements to avoid or delay the system reinforcement uprate on the North Coast.

[10] NW Natural's IRP Reply Comments LC-71, page 32, filed 11/19/2018

NW Natural has multiple ongoing internal projects, as described during a recent Technical Working Group stakeholder workshop and in the GeoTEE pilot, about how to alter our distribution system planning to make it a more forward-looking process that can accommodate non-pipeline solutions that have longer lead times to expand the non-pipeline options that can be feasibly analyzed and implemented going forward.

On-System Low Carbon Supply (RNG and Hydrogen) as Distribution System Resources

NW Natural has evaluated in detail the possibility of using on-system low carbon gas supply ("RNG") resources as on option for system planning and is currently actively evaluating projects that could serve this purpose (including the methanated hydrogen project in Eugene described in IRP Update #3). These projects typically have multi-year development timelines, but NW Natural is hopeful they can be an integral part of the Company's system planning going forward. NW Natural is recognized as a pioneer in incorporating the true value of low-carbon resources, inclusive of the capacity/reliability value on-system resources provide, as evidenced by the numerous citations of NW Natural's work by MJ Bradley in their briefs about renewable natural gas.[11]

With this background, in its comments Staff recommends:

> *NW Natural should respond in its Reply Comments regarding whether RNG located near to Oregon load may provide reliability and resiliency value that has not yet been considered in the RNG evaluation methodology.*[12]

NW Natural does incorporate reliability value for on-system low carbon resources in its evaluation methodology, and this reliability value is the "distribution system capacity value" described in the Company's methodology approved by the Commission in UM 2030.[13] As far as we can gather, we are the first utility to incorporate this value into natural gas utility resource evaluation in North America. This value was described in the initial methodology as:

> *The avoided distribution capacity costs (D) applied to on-system supply resources (in this instance RNG) will be consistent with the methodology used for energy efficiency in the most recently filed IRP. As load within its service area grows NW Natural must reinforce its distribution system to alleviate bottlenecks where we see pressure drops or other indications of insufficient pressure. If these on-system resources inject gas on the correct side of the bottleneck on the peak hour the additional gas supports pressurization of distribution system, which can delay or avoid system reinforcement projects.*[14]

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[11] See https://www.mjbradley.com/news-events/mjba-releases-series-issue-briefs-renewable-natural-gas
[12] See Staff comments for LC-71 IRP Update #3, page 8
[13] See OPUC Docket No. UM 2030 and OPUC Order No. 20-403
[14] See LC 71, UM 2030 - NW Natural's Revised Appendix H from 2018 Integrated Resource Plan, page H.15

Staff's initial comments regarding NW Natural's inclusion of a capacity/reliability value for on-system resources in UM 2030 were:

> *Staff does not take issue with the possible benefit of an on-system RNG resource which might inject gas on the correct side of a bottleneck, on the peak hour, and thus support pressurization, which might delay or avoid system reinforcement projects. However Staff is not convinced that, separate from this circumstance, there is a distribution system capacity cost benefit to RNG. A unit of conventional gas saved due to energy efficiency is not consumed and thus does not tax the gas distribution system. However, this logic (and benefit) fails to hold for RNG: a unit of RNG may displace a unit of conventional gas, but it is still consumed, and thus does tax the gas distribution system. Staff acknowledges this dynamic is different from that of the gas transportation system, where an on-system RNG resource does avoid the need to tax the gas transportation system with some units of gas, thus rendering avoided associated transportation costs.*[15]

NW Natural's response to Staff's comments were:

> *NW Natural recognizes Staff's concern, but disagrees with the premise that valuing benefits associated with RNG is inherently different to valuing energy efficiency. The key distinction regarding distribution system capacity costs is where there is a constraint, any of the options to help relieve that constraint – be they traditional pipeline related options or non-pipeline solutions like demand response (GeoDR), energy efficiency targeting peak loads (GeoTEE), or on-system supply like RNG (GeoRNG) – must either reduce peak load or increase the ability of the system to deliver on peak in the constrained area. For instance, when energy efficiency reduces peak load within a constrained area – and only when it reduces peak load in the constrained area – does it avoid near term distribution system costs. The gas that would have been consumed during peak periods, but was saved via energy efficiency, is now left in the pipeline to serve peak requirements for other customers in the constrained area. Similarly, additional gas (in this case RNG) injected onto the system within the same area also serves this capacity need. In this sense there is real value to the distribution system for having on-system pressure support from RNG projects in the same manner as other distributed resources, such as demand side management programs.*
>
> *In fact, peak savings from energy efficiency in some areas avoid vastly different near-term costs than peak savings from energy efficiency in other areas, and this is also true for RNG injections directly onto the distribution system and other distribution capacity resources as well. From a practical perspective, calculating site-specific distribution system avoided costs are challenging and bring up larger questions about fairness and equity across customers. In reality, the distribution system value via avoided costs provided from energy efficiency is different for nearly every customer NW Natural serves. Larger homes that consume more gas would have a higher avoided distribution*

[15] See https://edocs.puc.state.or.us/efdocs/HAC/um2030hac16519.pdf pg. 4.

> *capacity value and homes in non-constrained areas would have no near-term avoided distribution capacity value.*
>
> *However, over the long term, peak savings from energy efficiency, demand response and system support from on-system supply resources from all areas of the distribution system are likely to avoid distribution system capacity investments. In order to calculate site specific avoided distribution capacity costs to be applied to any distribution system capacity resource would require understanding the counterfactual. In other words, what system reinforcement projects would be needed, when they would be needed, and how much they would cost over a 20-30-year planning horizon would be required to make this site-specific avoided cost estimate. Forecasting this counterfactual is very difficult to achieve with a reasonable degree of certainty and would lead to outcomes that many would consider unfair (for example different energy efficiency incentives for customers across the state).*
>
> *Presumably this is the reason energy efficiency cost-effectiveness evaluation uses a statewide average for these avoided distribution system costs to evaluate energy efficiency programs. NW Natural believes this approach makes sense for energy efficiency and that applying IRP Guideline 1(a) is also appropriate, meaning a statewide average for distribution system costs avoided should be applied to all distribution system capacity resources, including other non-energy efficiency and non-pipeline solutions, such as on-system RNG.*[16]

In its final report, Staff concluded with the following and recommended that the Commission approve the low carbon resource evaluation methodology:

> *Staff's final point raised in comments was a question about whether the methodology may be applying a distribution system capacity cost benefit too broadly. In Phase One Reply Comments, NW Natural responded and Staff was satisfied this benefit is applied correctly.*[17]

NW Natural looks forward to additional engagement regarding *resiliency*, starting first with a discussion amongst stakeholders about its definition. The Company notes that reliability and resiliency are often used interchangeably, but can mean different things for utility resource planning. For one definitional distinction, the American Gas Foundation defines each as the following:

***Resilience** is defined as a system's ability to prevent, withstand, adapt to, and quickly recover from a high-impact, low-likelihood event such as a major disruption in a transmission pipeline. In comparison, **reliability** refers to a systems' ability to maintain energy delivery under standard operating conditions, such as the normal fluctuations in demand and supply.*[18]

[16] See https://edocs.puc.state.or.us/efdocs/HAC/um2030hac9501.pdf pgs. 2-3.
[17] See *https://edocs.puc.state.or.us/efdocs/HAU/um2030hau121211.pdf pg 5.*
[18] https://gasfoundation.org/2021/01/13/building-a-resilient-energy-future/

NW Natural looks forward to additional engagement on the topic of resiliency for all resources, including on-system gas supply resources like RNG and hydrogen. It is NW Natural's position that resiliency is connected to the assumption discussed above that the Company hopes to reconsider with stakeholders that resources are assumed to be 100% reliable.

Additionally, Staff submitted a Data Request (DR) regarding the ability of the North Coast Feeder uprate to safely accommodate 10, 20, or 30 percent hydrogen.[19] The Company explained that blending hydrogen in the pipelines would not alleviate local pressure concerns under most circumstances given that hydrogen is less energy dense (i.e. the same amount energy occupies a larger volume within a pipe for hydrogen relative to natural gas), such that adding hydrogen to the system, all else equal, would exacerbate pressure issues on the system. However, the uprated pipeline should be able to accommodate hydrogen-blended gas without any fears of hydrogen leakage.

It is also important to point out that NW Natural is both independently, and as part of consortiums, determining the amount of hydrogen that can be safely blended into the Company's distribution system as well as working to understand what will be required to make the system appropriately capable of delivering hydrogen blends. As such, the Company generally agrees with the asks of stakeholders regarding hydrogen in their comments, and will continue to update stakeholders on this work on NW Natural's policy in each IRP – including a detailed write up in the 2022 IRP. The Company views hydrogen, and methanated hydrogen, as a critical resource as NW Natural decarbonizes its system, and therefore will complete all of the asks provided on this topic.

4. INPUT AND METHODOLOGY UPDATES

Load Forecast

Staff makes two recommendations regarding the load forecast. First, Staff recommends NW Natural follow:

> "(*A) forecasting principle of parsimony when selecting load forecasting interaction terms, including them only when they are believed to help explain changes in the load forecast."*[20] They continue that "(*U)sing multiple interaction terms has a risk of overfitting of the load forecasting models, while Staff's recommendation of a forecasting principle of parsimony can prevent model overfitting*.[21]

Staff's second concern is the with the probabilistic approach to forecasting peak capacity need, specifically the length of the data series used to establish NW Natural's capacity need. "*Staff's concern is that the Company is including too cold of a peak day*."[22] Referencing Figure 3.36 in

[19] OPUC DR 122 in Docket No. LC 71
[20] See Staff comments for LC-71 IRP Update #3, page 12
[21] ibid
[22] See Staff comments for LC-71 IRP Update #3, page 13

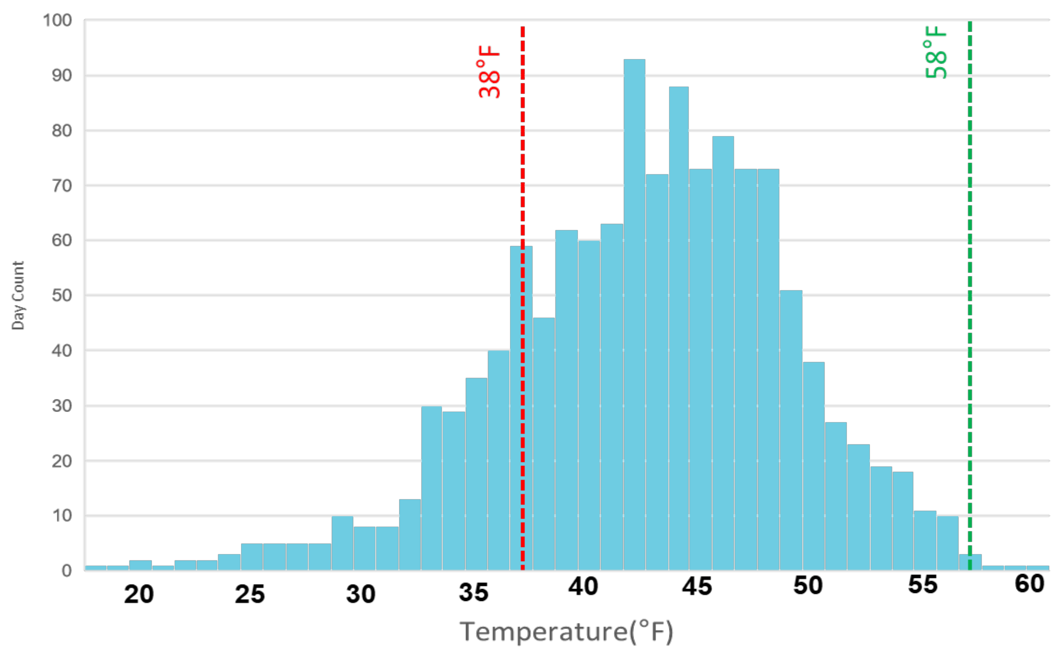
the Company's 2018 IRP, Staff concludes the figure, "*shows that the coldest day under the new methodology is above the actual coldest day in 100 years but below the coldest day in the most recent 30 years*."[23]

The Company appreciates Staff comments and notes that since these comments were submitted, NW Natural held a Technical Working Group that Staff referred to in their comments and as requested by Staff in their 2018 IRP recommendations.That TWG was held on June 3, 2021 and the Company hopes it was able to address Staff's concerns in addition to our written response below.

In regards to Staff's first concern about parsimony of the model, NW Natural understands how, all else equal, increasing the number of independent variables in a regression reduces the degrees of freedom and can lead to overfitting the model. However, by including interaction terms into the daily system load model the Company can account for non-linear interaction effects across a wider range of temperatures. This allows for far many more observations to be included into the model to estimate/predict load at peak day temperatures, which in turn leads to more degrees of freedom and less risk of overfitting the model.

The peak day temperature that the Company is planning for is about an 11°F day. This is several degrees colder than any data points in the training data set for the model with load data going back to 2009.[24] Figure 2, shows a histogram of temperatures used in the daily system load model for peak planning.[25]

Figure 2 - Histogram of Winter Temperatures (Nov-March) since 2009



[23] ibid
[24] Load data necessary for the regression modeling is limited, but the Company has weather data much further back in history to inform the peak planning standard.
[25] Days November through march and less than 58°F are used for the firm sales peak day regression.

Prior to using the interaction terms (i.e. in the 2016 IRP), the daily system load model relied only on data points less than 38°F to account for the impacts to load from other driver variables (e.g., wind speed or number of customers) which are magnified at colder temperatures. The 2016 IRP showed that including these other driver variables improved the ability to predict firm sales load versus a model using only temperature under forecasts load at the coldest temperatures.[26] Figure 3 has been updated and shows the same conclusion.

Figure 3 - Firm Sales Temperature Only Model

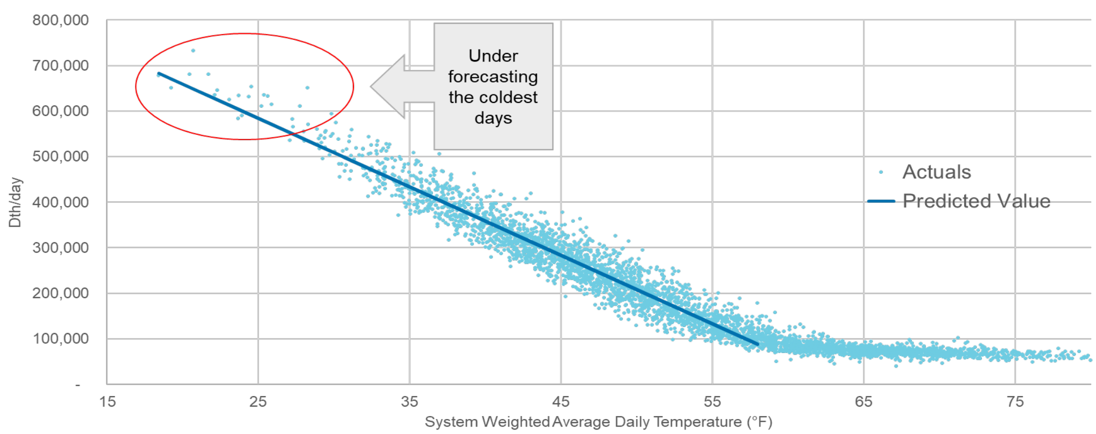
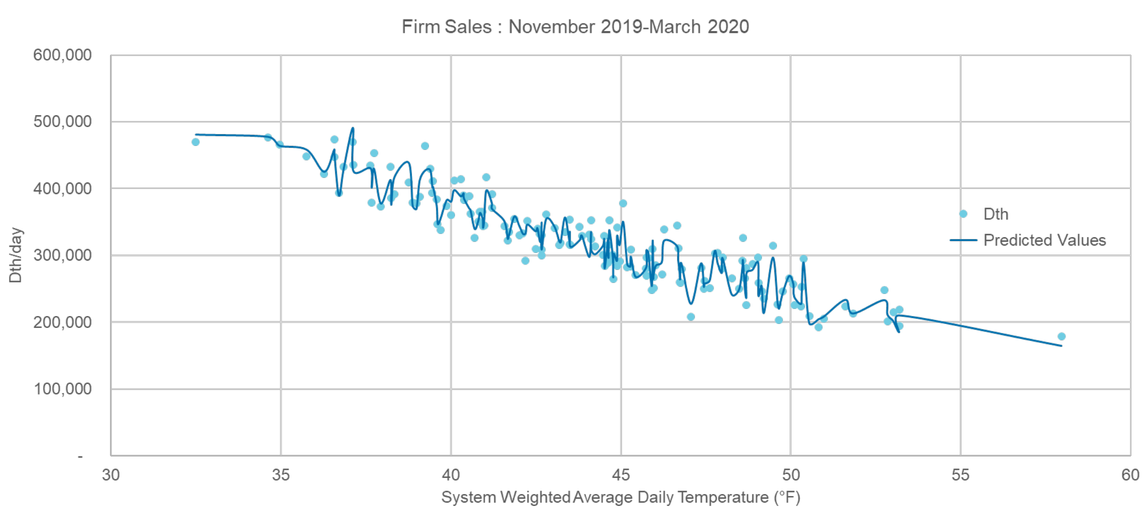


Figure 4 zooms down to a single heating season (November 2019-March 2020) and shows predicted values using the model with interaction terms. This model accounts for variation beyond temperature and performs far better at the coldest temperatures than the temperature only model. Performance at the coldest temperatures is the key metric for this model, since its primary purpose is estimating peak day load.

Figure 4 - Firm Sales Model with Interaction Terms



[26] See 2016 IRP LC-64, Appendix 2 "Peak Day Aggregate Use Per Customer Forecast Technical Details", pages 2A.38-2A.45

Table 3 shows an updated comparison between the model with interaction terms and a model without the interaction terms.

Table 3 - Degrees of Freedom Comparison

Model	Data subset	# of independent variables	# of Observations	Degrees of Freedom
No Interaction Terms	≤ 58°F	12	338	325
Interaction Terms	≤ 58°F; Nov-March	21	1,735	1,713

NW Natural thanks Staff for their continued engagement through our technical working groups and raising useful questions about over fitting a model. The Company believes that the increase in the degrees of freedom, which are the primary metric for risk of over fitting a model, are sufficient to justify including interaction terms which account for the non-linear effects of temperature, albeit mostly noticeable at the coldest temperatures of the year (see Figure 5). For the majority of temperatures throughout the year, a temperature-only model is sufficient for load forecasting.

Staff states concern regarding the change in the Company's capacity standard. The company held a TWG in June 2021 to address this concern. Staff is reiterating their concerns of :

1. The Company is including too cold of a peak day.
2. The Company's methodology described on pages 3.38-3.43 of the IRP appears to relate to a negative binomial distribution of weather[27].

NW Natural appreciates Staff's inquiries and understands there is likely some confusion about the new probabilistic planning standard. In response to Staff's comments for peak day weather, NW Natural would like to clarify a few points, which are more nuanced.

First, in previous IRP's the Company has included high and low customer count scenarios (called "sensitivities" in the 2018 IRP) in its risk analysis and will continue to do so in the future. To clarify, the high and low customer count scenarios did not replace the stochastic customer count, but the stochastic simulation of customer counts was simply removed from the Monte Carlo process used for the firm sales peak day simulation. Staff is correct that this was done to focus on the uncertainty of weather and other driver variables that impact load going into any future heating season. The Company made this change as the number of customers will become relatively certain at the start of any future winter, whereas weather and other driver variables will remain relatively uncertain. Additionally, it might be helpful to clarify that Monte Carlo simulations are used for several different models throughout the IRP. In other words, the Company removed the stochastic customer count simulation from the firm sales peak day modelling, but will still include stochastic variables in the Company's risk analysis.

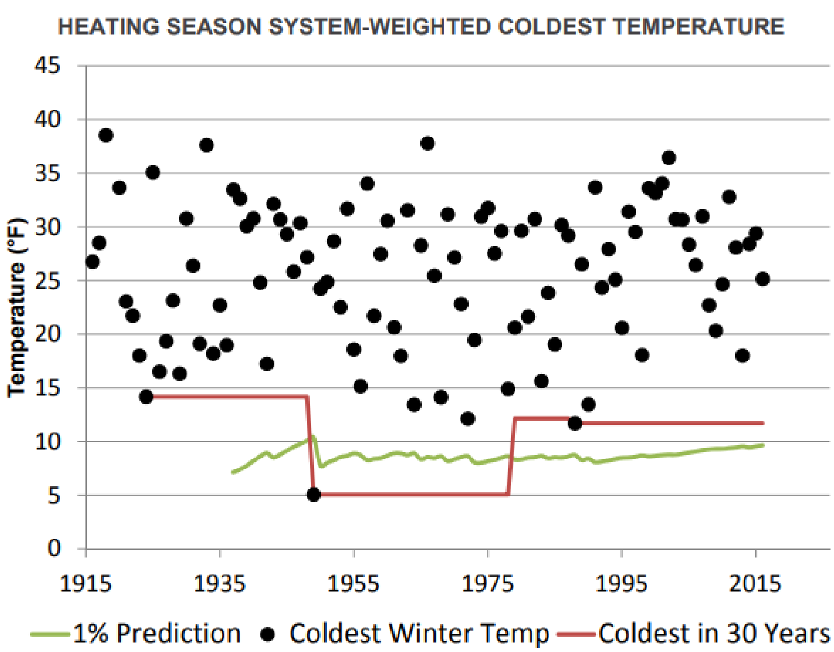
[27] See Staff comments for LC-71 IRP Update #3, page 12-13

Second, system weighted weather variables are utilized for the daily system load model from eleven different weather stations at various airports throughout the service territory. Weather from Portland International Airport (PDX) receives the highest weighting per the highest level of load associated with the area. The National Oceanic and Atmosphere Administration (NOAA) has max and min daily temperatures for PDX starting in 1938.[28] Most of the other ten weather stations have robust historical data. Any missing data from the ten other weather stations are imputed using regression modeling as a function of weather from PDX. Data from all eleven stations are used to calculate a system weighted daily temperature (average of daily maximum and minimum). These weights and weather stations are consistent with the stations and weighting used for weighting the weather variables for the daily system load modeling. The coldest system weighted day in each historical gas year is used for the Monte Carlo simulation.

Third, Figure 5: Relative Stability of a Risk-based Planning Standard (Figure 3.36 from 2018 IRP; Figure 2 in Staff's comments) shows only the coldest daily temperature per each historical heating season. The Monte Carlo process used for the firm sales planning standard is multi-dimensional that simulates values for several load drivers. Figure 5 showing temperature only was necessary to graphically represent the Monte Carlo process in a single dimension. The values for the 1% prediction green-line shown by Figure 5 are illustrative only for the purpose of explaining the stability advantage of a probabilistic stable planning standard.

Figure 5 – Figure 3.36 from the 2018 IRP

Figure 3.36: Relative Stability of a Risk-based Planning Standard



[28] NOAA has data prior to 1938 for Portland. This data is reflected in Figure 2: Relative Stability of a Risk-based Planning Standard, but is recorded at a different station. The Monte Carlo simulation was limited to 1938 to be consistent with the data being used for the daily system load model.

Staff's concern related to the Company's resulting design peak day reads:

"…that the Company is including too cold of a peak day. For instance, in the figure above [Figure 5], the most recent 20 years of data visually would have a very significantly warmer coldest day than the Company's new 99 percentile approach[29]*."*

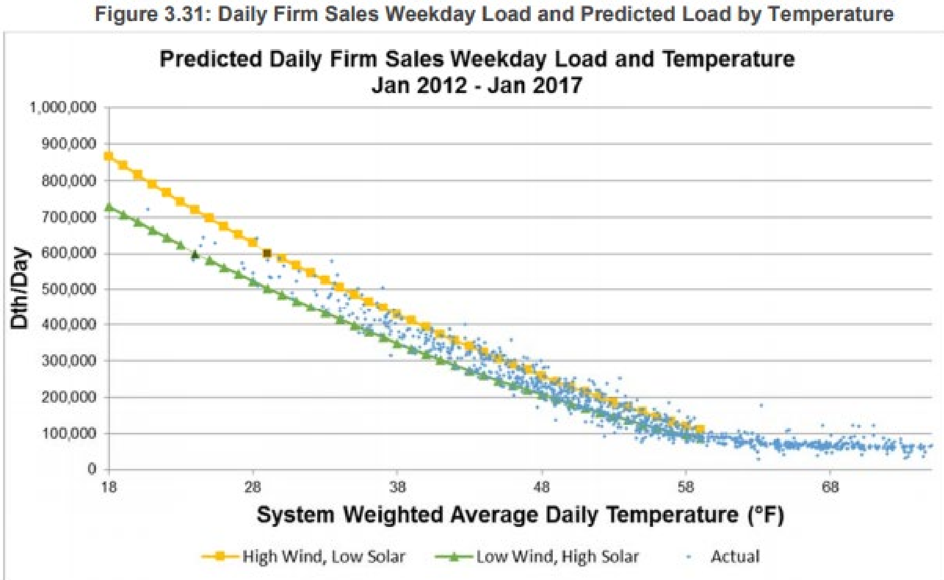
The day Staff is referring to occurred in 1989 with a temperature of 10.5°F. Even though the 10.5°F temperature in 1989 is above the 1% (illustration-only) prediction line, the combination of other weather load drivers that occurred that day (e.g., wind speed that equaled 22 mph that day) placed that day higher than the 99th percentile in terms of load. Using the same weather from February 3, 1989 and applying current customer counts and trend values, the daily system load model predicts a load of 1,056,000, while the 99th percentile from the firm sales peak day simulation equals 997,000.[30]

For additional context, Figure 5 shows historical coldest daily temperature values by gas year, but the 1% prediction line is based on simulated data from a normal distribution using historical data for each given gas year to define the mean and standard deviation of the distribution. In other words, the 2015 year in Figure 5 has 100 years of data to define the mean and standard deviation of the simulation, whereas the 1940 gas year, where a 5°F day occurred, only has 35 data points defining the mean and standard deviation. This a main reason why the green line becomes more stable over time as more data points are included in the sample. For the 2018 IRP Update #3 data from 1938 through 2019 gas year for the coldest day in each gas year was used to define the mean and standard deviation of the distribution peak day temperatures.[31]

There are many factors that impact load. Within a probabilistic approach there is no single temperature that defines the peak conditions. For example, the 99th percentile load may result from an extremely cold day with no wind or a slightly less cold day with high wind speeds. This is best illustrated by Figure 3.31 in the 2018 IRP (reproduced as Figure 6), which shows how the same load can occur under different conditions.

[29] See Staff comments for LC-71 IRP Update #3, page 13
[30] See Figure B.11 Firm Sales Peak Day Load Forecast of the 2018 IRP Update #3; the 997,000 Dth/day number included minor energy efficiency and emerging market adjustment.
[31] For the 2018 IRP 100-years of data was used. NW Natural updated the Monte Carlo process to use data since 1938 to be consistent with the weather stations used in the daily system load model.

Figure 6: Figure 3.31 from 2018 IRP



Using the output from the simulation, Table 4 summarizes different simulated variables for the 4,000 simulations around the 99th percentile load.

Table 4 - Mean Values for Peak Day Weather Conditions for 4,000 Simulations Around the 99th Load Percentile

Variable	Mean
Temperature	11.2°F
Previous Day Temperature	15.6°F
Wind Speed	14.2 mph
Solar Radiation	2,187 watts/m^2/day

To reiterate, the 11.2°F mean from the simulation data around the 99th load percentile is the average of the peak day temperatures used for IRP planning.This is well above the green line 1% line shown in Figure 5 for illustrative purposes and slightly above the 10.5°F daily temperature seen on February 3, 1989.

Lastly, Staff's concern related to Figure 3.35 in the 2018 IRP relates to using a negative binomial distribution. The negative binomial distribution is used for illustrative purposes only. Figure 3.35 in the 2018 IRP is used to illustrate that using the hightest load requirement in the past 30 years is not the equivalent of the planning for a 1-in-30 event. In fact, from our simulation, the Company has shown that given the high wind speeds and severe cold temperatures seen on February 3, 1989, this event exceed a 1-in-100 year event. An additional figure, Figure 7, was shared during a TWG, but not included in the IRP.

Figure 7 – Probablity of 1-in-100 event occurring less than 30 years apart

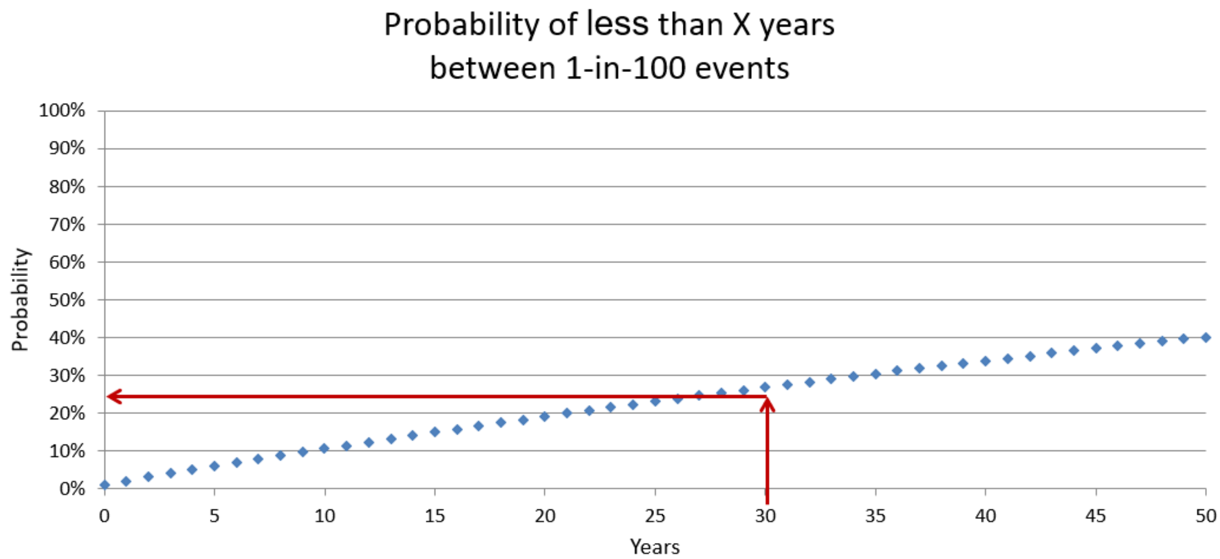


Figure 7 demonstrates that even though a 1-in-100 year event was experienced a little over 30 years ago, another 1-in-100 year event still retains a positive probability of occurring even in the following year. The negative binomial distribution is only used for this demonstration to express the advantage of using a probabilistic planning standard and is not used in the actual Monte Carlo simulation for peak day firm sales load.

Avoided Costs

Staff comments included the following relative to Avoided Costs:

> *Staff notes that the load profiles used in this IRP Update have not yet been reviewed in compliance with Order No. 19-073 and that different load profiles are used for the annual calculation of avoided costs in Docket No. UM 1893. Staff suggests that the Company take steps to address this Staff Recommendation before the next IRP is filed.*[32]

NW Natural completed a review of the different load profiles available for avoided costs when it became the first gas utility to provide end-use specific avoided costs in the region in its 2016 IRP. Given that there were no natural gas specific load profiles available in the region, NW Natural developed its own using a combination of its own data and other sources. NW Natural stands by this decision and notes that it was this primary work that allowed the Company to work with Energy Trust to estimate peak savings from each energy efficiency measure, without which the ongoing GeoTEE pilot would not be possible. It is also of note that the Avoided Cost workbook format Staff has adopted in UM 1893 is based upon this original work that was completed by NW Natural and provided to Energy Trust in support of the 2016 IRP. Most of the load shapes that Staff now employs for all natural gas energy efficiency programs in Oregon via UM 1893 were also developed by NW Natural. Furthermore, this work was presented in detail in

[32] See Staff comments for LC-71 IRP Update #3, page 9

the 2016 and 2018 IRPs as well as the Technical Working Groups that supported the IRPs. NW Natural also held an additional meeting with Staff after the 2018 IRP was filed to take Staff through the Company's avoided cost methodologies. NW Natural has also participated in UM 1893 processes and provided Staff with a submission in each year based upon the most recently acknowledged IRP as well as the Company's most up-to-date estimates, even though both submissions are not required by Staff (though are requested).

Given this history, NW Natural is unsure what Staff is hoping to be reviewed and by whom, though is willing to engage further with stakeholders on this topic. The Company views its role as calculating avoided costs as accurately and up-to-date as possible while complying with applicable laws and rules, and transparently show that work through the IRP and UM 1893 processes. NW Natural has done that in its IRPs and in UM 1893, and has also done so in its Update #3 to the 2018 IRP. With this, the Company views the primary review role of these calculations to be undertaken by stakeholders and request changes through comments if they believe it would improve the accuracy of avoided costs, which represent the marginal cost of serving the next unit of load. It is NW Natural's understanding that Staff decides what load shapes it will use in this work as it applies the calculation techniques developed by NW Natural to develop end-use load shapes in the UM 1893 workbook.

As this discussion has been ongoing and NW Natural has attempted to address Staff concerns – and is more than willing to provide another additional workshop on avoided costs to take stakeholders through the Company's work again – if Staff recommends that NW Natural use regional electric load shapes developed for electric energy consumption NW Natural hopes it can make that recommendation in comments. As NW Natural has stated on previous occasions, the Company believes that the utilities are in the best position to collect the data and estimate end use load profiles for their customers. However, we understand how it could be reasonable to come to a different conclusion, and if the Commission directs the utility to use other load shapes and data, NW Natural will comply. NW Natural hopes that the avoided costs provided in Update #3 are used by Staff for official budgeting and program development going forward if the Update is acknowledged by the Commission.

5. CONCLUSION

NW Natural thanks stakeholders for the thoughtful review of Update #3 to its 2018 IRP, particularly the willingness to entertain action items through this process. The Company believes it has made a strong case for the two Action Items in the Update and agrees with most stakeholders that NW Natural has provided sufficient analysis to support acknowledgement of the two items in 2018 IRP Update #3.

Furthermore, the Company looks forward to analyzing and discussing many of the issues brought up in stakeholder comments as well analyzing the upcoming requirements of the Oregon Department of Environmental Quality's Climate Protection Program in the 2022 IRP.

Ryan Bracken 6/14/21

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NW Natural

Engineering Procedure

NW Natural

D-10

Design Procedure **Regulator and Relief Set Point Requirements**	
Revision: 03	Effective Date: 12/14/2018
Approved: *Andy Fortier*	Reviewed: *Chanda Cross*

1. Purpose

This procedure defines the set point requirements for regulators and reliefs for gate stations, regional stations, district regulators, primary service regulators, and gas supply meter sets.

2. Definitions

<u>MAOP</u> – Maximum Allowable Operating Pressure.

<u>Regulator Maximum Design Set Point</u> (psig) – The maximum pressure the regulator can be set at; equal to the outlet MAOP. See Appendix Table 2.

<u>Regulator Maximum Design Capacity</u> (mscfh) – The capacity of the regulator at the Maximum Design Set Point. This is the capacity that is used for the annual Pressure Relief Capacity Report.

<u>Regulator Operational Set Point</u> (psig) – The outlet pressure the regulator is set at for normal operations. For gas supply meter sets, this is the delivery pressure for the customer. See Appendix Table 1.

<u>Regulator Operational Capacity</u> (mscfh) – The capacity of the regulator at the Operational Set Point.

<u>Relief Maximum Design Set Point</u> (psig) – The maximum pressure the relief can be set at. See Appendix Table 2.

<u>Relief Maximum Design Capacity</u> (mscfh) – The capacity of the relief at the Maximum Design Set Point.

<u>Relief Operational Set Point</u> (psig) – The pressure the relief is set at for normal operations. See Appendix Table 1.

<u>Relief Operational Capacity</u> (mscfh) – The capacity of the relief at the Operational Set Point. This is the capacity that is used for the annual Pressure Relief Capacity Report.

3. Procedure

3.1 Set Point Requirements

Regulators and reliefs shall be set as indicated in the Maximum Operational Set Point table (see Appendix Table 1). The Director of Engineering or designee must approve any deviation from these requirements – however, for gate stations, regional stations, district regulators, and primary service regulators, the regulator set point may be lower, if needed.

For Engineering and Code Compliance purposes only, regulator and relief capacities must be designed based on the Regulator Maximum Design Set Point (see Appendix Table 2) and the Relief Operational Set Point (see Appendix Table 1). The Director of Engineering or designee must approve any deviation from these requirements.

<u>Worker-Monitor Regulator Settings</u>

Worker-monitor regulator capacities are reported per the calculated chart capacities, less 30%. The monitor regulator shall be set per the Maximum Operational Set Point table (see Appendix Table 1), and the worker regulator shall be set at a lower pressure than the monitor (typically 5 psig less).

<u>Token Relief Settings</u>

A token relief shall be installed between the worker and monitor regulators, and set at a pressure between the worker and monitor set-points (up to a maximum of MAOP). If pressure telemetry between the worker and monitor regulators is installed and monitored by Gas Control, then a token relief is not required.

<u>Annual Pressure Relief Capacity Report Calculation</u> (as required per CFR 192.743)

This calculation validates the relief capacity (R1) based on complete failure (full-open) of the largest capacity regulator (R2) of a station.

Relief Capacity (%) = (1- ((R1-R2)/R1)) * 100

R1 – Relief Maximum Operational Capacity
R2 – Regulator Maximum Design Capacity

4. Training Requirements

N/A

5. Periodic Review

This procedure shall be reviewed at least every three years.

6. Impacted Departments

Engineering

Code Compliance
System Operations

7. References

SPO/W 743 – District and Primary Service Regulators
CFR 192.201 – Required Capacity of Pressure Relieving and Limiting Stations
CFR 192.743 – Pressure Limiting and Regulating Stations: Capacity of Relief Devices

8. Revision History

Revision 03 12/14/18 Updated to current format and change set point requirements for the Pressure Relief Capacity Report.

9. Appendixes

Table 1: Maximum Operational Set Points for Regulators and Reliefs

MAOP (psig)	**Maximum Operational Set Points (psig)**	
	Regulator	**Relief**
12 – 60 psig	MAOP minus 1 psig, or delivery pressure for gas supply meter sets	MAOP plus 1 psig
> 60 psig	MAOP minus 5 psig, or delivery pressure for gas supply meter sets	MAOP plus 5% MAOP

Table 2: Maximum Design Set Points for Regulators and Reliefs

MAOP (psig)	**Maximum Design Set Points (psig)**	
	Regulator	**Relief**
12 – 59 psig	MAOP	MAOP plus 6 psig
>= 60 psig	MAOP	MAOP plus 10% MAOP

Design Procedure **System Reinforcement Standards**	
Revision: 00	Effective Date: 06/14/2019
Approved: *Joe Karney*	Reviewed: *Andy Fortier*

1. Purpose

This procedure defines the system reinforcement standards that NW Natural utilizes to determine when a transmission, high pressure distribution, or Class B distribution system needs to be reinforced.

System reinforcement standards are a required component of the transmission, high pressure distribution, and Class B distribution system planning process. The standards are based on multiple criteria that indicate conditions representing a pipeline nearing peak capacity, sub-standard regulator performance, customers not being served with adequate pressure or volume, etc. The system reinforcement standards represent trigger points which indicate systems under stress and in need of imminent attention to reliably serve customers.

Pressures that are experienced during cold weather events that meet the criteria defined below may be observed and documented by means of:

- SCADA Data Pressure Logs.
- Portable Pressure Recorders (PPR's) Temporarily Sited in the field.
- Cold Weather Survey Points that are manually read by a NW Natural Technician.
- Pressures at customer locations documented by manual pressure readings or Industrial Billing System devices.
- Gas Control Room records of System Operations Crew activities in the field, including by-passing regulator stations, manual pressure readings, or reports of system outages.

Once experience or modeling has shown that the system reinforcement standards defined below have been violated for a transmission, high pressure distribution, or Class B distribution system, then an investigation will be initiated. This investigation may include further validation of pressure data to confirm system modeling, preliminary design of system reinforcement projects, potential alternatives to these projects, and estimated scope, schedules, and budgets. These projects will then follow Engineering Project Management and IRP process for review and approvals.

2. Definitions

IRP – Integrated Resource Plan

3. Procedure

3.1 Transmission and High Pressure Distribution Systems

The system reinforcement parameters associated with peak hour load requirements for transmission and high pressure distribution systems (systems operating at greater than 60 psig) are:

- Experiencing at least a 30% pressure drop over the facility that indicates an investigation will be initiated.
- Experiencing or modeling a 40% pressure drop that indicates reinforcing the facility is critical, as a 40% pressure drop equates to an 80% level of capacity utilization[1].
- Consider minimum inlet pressure requirements for proper regulator function in addition to total pressure drop for pipelines that feed other high pressure systems[2].
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance.
- The ability to meet firm service customer delivery requirements (flow or pressure).
- Identified in the IRP associated with supply requirements or needs.

[1] This standard is based on the Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised, Chapter 2: Gas Flow Calculations, page 111.

[2] This standard is based on pressure regulator manufacturer requirements. NW Natural has a variety of pressure regulators in its systems, and the manufacturer requirements for minimum inlet pressure for proper regulator function are used on a case by case basis. Typical manufacturer and models of pressure regulators NW Natural uses are the Mooney Flowgrid, the Honeywell American Axial Flow, and the Fisher 627.

3.2 Class B Distribution Systems

The system reinforcement parameters associated with peak hour load requirements for Class B distribution systems (systems operating at 60 psig or less) are:

- Experiencing a minimum distribution pressure of 15 psig that indicates an investigation will be initiated.
- Experiencing or modeling minimum distribution pressure of 10 psig that indicates reinforcement is critical[3].
- Near-term growth indicated by one or more leading indicators (e.g., new road construction, a new subdivision, or planned industrial development) may require reinforcing a system that currently has satisfactory performance.
- Firm service customer delivery requirements (flow or pressure).

4. Training Requirements

Engineering

5. Periodic Review

This procedure shall be reviewed at least once every three years.

6. Impacted Departments

Engineering
Construction
System Operations
Gas Control
Strategic Planning

7. References

Gas Engineering and Operating Practices (GEOP), Volume 3, Distribution, Book D-1, System Design Revised

49 CFR §192.381	Service lines: Excess flow valve performance standards
SPO/W 623	MAOP for Class A and B Distribution Systems
SPO/W 627	MAOP for Transmission and Distribution Lines with MAOP>60 psig

[3] This standard is based on the minimum inlet pressure required for an Excess Flow Valve (EFV) to properly function, per 49 CFR §192.381 Service lines: Excess flow valve performance standards.

8. Revision History

Rev 00	06/14/19	New Procedure

9. Appendixes

None