BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

NWN 2014

INTEGRATED RESOURCE PLAN

In the Matter of NORTHWEST NATURAL GAS UTILITIES COMPANY, dba NW NATURAL 2014 Integrated Resource Plan	STAFF'S FINAL COMMENTS

The Public Utility Commission of Oregon Staff (Staff) file these final comments on Northwest Natural Gas Company's (NWN or Company) 2014 Integrated Resource Plan (IRP or Plan) These final comments include a summary of Staff's initial comments and the opening comments submitted by Citizens' Utility Board of Oregon (CUB), and also address NWN reply comments. Staff's final comments and recommendations on the Company's 2014 Plan are organized according to subject and begin by addressing the Action Plan. A final order is expected to follow the Commission Public Meeting on February 24, 2015.

Staff finds that NWN's 2014 IRP generally adheres to the Guidelines[1] and relevant orders related to least-cost, integrated resource planning. Staff identified several specific areas of interest that warranted further analysis and review in its initial comments. For the most part, between subsequent additional discovery, explanations, and proposed revisions to the Action Plan, the issues of initial concern have been adequately addressed for this IRP. However, Staff does recommend modified action items in the current Action Plan, as well as additional action items.

Summary of Staff's Initial Comments

Staff identified areas requiring further investigation and analysis of NWN's 2014 IRP in its initial comments, including future pipelines and alternative resources, Clark County distribution projects, refurbishments to the Company's Newport Liquefied Natural Gas (LNG) Storage Facility, long-term hedging strategy, gas requirement forecast, supply diversity and risk mitigation practices, demand-side resources and avoided cost determination, energy policies and environmental considerations, linear programming and risk analysis, and potential modifications to the Action Plan. While some issues have

[1] Docket No. UM 1056, Order No. 07-002 is Attachment A.

been addressed through on-going discovery or are discussed in NWN's reply comments, there are still areas that require additional analysis that will go beyond February 24, 2015.

Summary of CUB's Opening Comments

CUB primarily focused on NWN's long-term hedging strategy in its opening comments. They recommended additional time for review of the Company's hedging strategy prior to making a decision to modify its current hedging plan.

The Action Plan

NWN Action Item 1

1. *Load Forecasting*

    1.1 Continue to refine growth projections for the Clark County load center.

    1.2 Create a demand forecast scenario based upon the assumed construction of NIW's[2] methanol plants.

Staff Final Comments: Gas Requirement Forecast

Staff reviewed NWN's load forecasting methodology used in its 2014 IRP. Staff submitted data requests to obtain the explanatory data used in the Company's econometric forecasting models and to understand the assumptions used by the Company to develop the forecasts. Based upon this review, Staff offers the following observations:

General Comments

- A number of the econometric forecasts developed for the 2014 IRP do not use up-to-date (i.e. up to 2013) explanatory data. For example, the Company uses data through 2011 to develop their use per customer forecasts. Recent data is most relevant for forecasting and the most recent data available should be utilized by the Company in subsequent econometric forecasts.

Customer Forecasts

- The Company uses relatively short time periods of explanatory data to generate their long-term customer forecasts for some customer classes. For example, only two years of monthly data is utilized in the Oregon and Washington new residential single family customer forecasts. In contrast, six years of explanatory data are used to generate the Oregon new multifamily customer forecast. The company has stated that the reason that older vintages of data were not utilized for some customer classes is because NWN purges its billing data after a few

[2] Northwest Innovation Works

years. Staff recommends that NWN retain such data for at least ten years for use in subsequent forecasts. Staff also recommends that the Company either use all of the data available to them to develop econometric customer forecasts, or alternatively provide appropriate reasoning in the IRP for the time period of the explanatory data used.

- For each customer class,[3] a single econometric forecast was developed for each state (OR and WA) and then allocated to load. Developing separate econometric forecasts at the load center level would facilitate the incorporation of intrastate regional economic factors into the forecast. This would be particularly useful in Oregon where the Company oversees a variety of geographically distinct load centers.

Industrial Forecasts

- The Company produced industrial load forecasts at the state level and then allocated to load centers based on the historic distribution of productivity-adjusted manufacturing employment (PAME), and changes in forecasted PAME. Developing individual future forecasts at the load center or customer level would facilitate the use of load center/customer specific variables and likely increase the precision and explanatory power of the Company's forecasting models.

South Salem Feeder

- NWN is planning construction of the South Salem Feeder as a response to a forecasted increase in load. As mentioned above, Staff identified a number of ways that the Company's customer forecasts could be improved. The Company's customer forecasts were modeled by customer class at the state level and then allocated to load centers. Additionally, the customer class forecasts utilize as little as two years of explanatory data. Staff believes that a more granular forecast (i.e. at the load center level) developed with data from a longer time period would improve the precision of the Company's forecast and provide more convincing evidence regarding the need for the proposed South Salem Feeder. Staff continues to investigate this issue and plans to develop Salem-specific forecasts for residential and commercial customers.

NWN Action Item 2

2. *Resource Additions and Changes.*

[3] Customer classes include: residential new construction single family, residential new construction multi-family, residential conversions, commercial new construction, and commercial conversions. Existing customers are assumed to decline at a constant rate over time.

2.1 Acquire resources in the near-term consistent with meeting the Base Case firm sales load forecast.

a. Recall 30,000/day of Mist storage capacity from the interstate storage account effective May 2015 to serve the core customer needs reflected in the Base Case load forecast.
b. Complete Clark County distribution projects to address Vancouver load center needs — estimated timing of projects is over the next five years with an estimated total capital cost of $25 million.
c. Proceed with the Newport refurbishment project and continue investigating Portland Gasco refurbishment alternatives. Estimated timing of Newport refurbishment is over next three years at an estimated cost of $25 million.
d. Construct the South Salem Feeder to serve load growth in the Salem area – estimated timing is to begin permitting in 2015 with an in-service date in 2019; estimated cost of $25 million.

2.2 Additional actions related to changes to resource stack:

a. Given that segmented capacity is an interim solution, continue working with NWP to investigate options regarding both the Plymouth and Jackson Prairie storage facilities.
b. Explore alternatives with NWP for increasing contracted MDDO capacity at Vancouver gates, including but not limited to, TF-1 contract extensions and/or subscription for additional CD capacity at some future date.
c. Provide termination notice to NWP on the Company's existing Plymouth LS-1 and TF-2 service agreements by October 31, 2014 (effective November 1, 2015), unless NWP offers a viable economic alternative solution before that notice cut-off date.

2.3 Analyses to be performed for future pipelines and alternative resources:

a. Complete analysis regarding North Mist: refine cost estimates; quantify the value of the project's optionality created by upsizing the associated takeaway pipeline near-term versus at some future date(s); and research applicability of the Company's Hinshaw Exemption. NW Natural will submit this analysis for the Commission's review by May 2015.
b. Preserve the optionality of participating in both the Cross-Cascades and Pacific Connector interstate pipelines by working with the Project Sponsors and exploring what preserving this optionality requires. Timing is

contingent on other parties. Updates will be provided at the annual updates.

c. *Conduct cost risk analysis on acquiring capacity on the proposed Pacific Connector pipeline to ensure that the Company has fully analyzed its options should the project move forward. These analyses will be included in the next IRP.*

Staff Final Comments: Resource Additions and Changes

Staff reviewed NWN's proposed Resource Additions and Changes, submitting multiple data requests to the Company. Based upon this review, Staff offers the following observations:

The Clark County distribution projects are composed of five projects, as represented in Appendix 6 of NWN's 2014 IRP (i.e.; 119th Street, $5.4 million; Camas Reinforcement, $4.6 million; Washougal Extension, $4.5 million; 119th Street to Salmon Creek, $6.1 million; and Vancouver Core Replacement, $4.3 million). The aggregate cost of these five projects is approximately $25 million and the in-service date is 2017.

Staff indicated in its initial comments that the construction of this project may have already commenced, which would be the basis for excluding it from NWN's 2014 Action Plan. In NWN's reply comments, the Company represented that:

> Staff correctly points out that both the Clark County distribution projects and refurbishment of the Newport Liquefied Natural Gas (LNG) storage facility are phased projects where some phases have already commenced.

The Company also represented that it:

> believes that multiple phases characterize many capital projects and projects may not align well with the timing of the Company's IRP filings. However, the Company agrees to revise its Action Plan such that it is only seeking Commission acknowledgement on project phases that have not been started.

The Company proposed to modify the action item related to the Clark County distribution projects as follows:

> Complete those Clark County distribution projects included in Appendix 6 which have not yet started and which address, in part, Vancouver load center needs and have an estimated timing for completion within the next five years."

Staff agrees with the Company “that multiple phases characterize many capital projects.” As mentioned above, what the Company characterized the “Clark County distribution projects” as an aggregate is, in fact, a group of five projects that appear to be independent. (i.e., each project serves a different area of Clark County, for example, North Vancouver, Camas, Washougal, etc.).

As represented in NWN’s response to Staff Data Request 15, the construction of the 119th Street project has already commenced; therefore, it should be excluded from the Company’s IRP action items. As for the other projects, each projects’ capital costs does not exceed the Company- proposed threshold of $10 million[4] for distribution projects to be included in its IRP; on this premise, they should also be excluded from its Action Plan. The recommendation above is not based on the reasonableness of the need of the projects, but rather, it is based on timing. Threshold levels of capital expenditures (i.e., Company- proposed threshold of $10 million for distribution projects) have not been established. Staff recommends excluding this action item from the Company’s Action Plan.

The Newport LNG facility (Newport) consists of a 1,000,000 Dth capacity storage tank capable of processing about 5,500 Dth/day and a vaporization capacity of up to 100,000 Dth/day. This facility was commissioned in 1977. Because the Company’s pipeline system limits Newport to serving the central coast and Salem market areas, the full 100,000 Dth/day vaporization rate is not achievable. Instead, 60,000 Dth/day is the effective achievable limit on vaporization at this facility.

NWN is beginning a major refurbishment for Newport, which includes addressing issues with the liquefaction process including removal of carbon dioxide (CO_2), from the incoming natural gas stream, which has been very gradually collecting in the tank and settling on its floor in solid form (commonly known as dry ice). The dry gas issue at Newport is severe enough that in order to avoid weight issues on the floor of the storage tank, the Company has reduced the maximum quantity of LNG to be stored there from 1,000,000 Dth down to 900,000 Dth. Fortunately, so far this issue has not affected the daily vaporization rate and the reliance on Newport within the Company’s peak day resource stack.[5] The cost of the project is approximately $25 million and the in-service date is 2019.

Similar to the Clark County distribution projects, Staff indicated in its initial comments that the construction of this project may have already commenced, which would be a basis for excluding it from NWN’s 2014 Action Plan. Staff has corroborated that this project has commenced as indicated in page 3.19 of NWN’s 2014 IRP where the Company represented that refurbishment of the Newport facility has begun because this is the least-cost alternative.

In its reply comments, the Company represented that:

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[4] In page 6.1 of NW Natural 2014 IRP the Company proposed to include in its IRP “[m]ajor system reinforcement or system expansion projects with an estimated construction cost exceeding $10 million.

[5] See page 3.18 and 3.19 of NW Natural 2014 IRP.

> Staff correctly points out that both the Clark County distribution projects and refurbishment of the Newport Liquefied Natural Gas (LNG) storage facility are phased projects where some phases have already commenced.

The Company also represented that it:

> believes that multiple phases characterize many capital projects and projects may not align well with the timing of the Company's IRP filings. However, the Company agrees to revise its Action Plan such that it is only seeking Commission acknowledgement on project phases that have not been started.

The Company proposes to modify the action item related to the Newport refurbishment project as follows:

> Proceed with those projects not yet begun on the Newport refurbishment project and continue investigating Portland Gasco refurbishment alternatives. Estimated timing of Newport refurbishment is over the next three years.

It is unclear what the Company intended when mentioning "those projects not yet begun" when referring to the Newport refurbishment project. According to Attachment 4 to the Company response to Staff Data Request 18, the Newport refurbishment project consists of several activities, such as Pretreatment System, Liquefaction Improvement, Control Room Construction, etc. , some of which have already begun. Staff's understanding is that all the activities that compose the Newport refurbishment project are necessary for the project to be useful when finished; therefore, it should be treated as a whole when determining when the project has commenced. Staff analogy is that when, for example, a power generation facility project is undertaken, the acknowledgment is made for the entire facility, not just for certain activities such as the generator, turbine, transformer, control room, etc. For this reason, Staff recommends that the refurbishment of Newport be removed from NWN's 2014 Action Plan.

The South Salem Feeder consists of installing a 12 inch pipeline from the Mid-Willamette Valley Feeder to the South Salem feeder system. This project's cost estimate is approximately $25 million and the in-service date is 2019.

In Staff Initial Comments, Staff indicated that it was unclear how the Company modeled alternative approaches to the South Salem Feeder. In addition to the alternatives proposed by the Company, Recallable Agreements and DSM should be considered as alternatives to the South Salem Feeder or as a means to delay the construction of the South Salem Feeder.

With regard to Recallable Agreements, in response to Staff Data Request 17, the Company represented that approximately 55 customers take service under rate schedules 31 and 32 in the Salem load center. NWN represented that assuming hypothetically that all these customers agree to a recall agreement, it would eliminate the Salem shortfall until 2025. If hypothetically, only 10 percent of these customers agreed to a recall, it would eliminate the Salem shortfall for one year.

For the reasons explained in Staff's comments above, Staff will recommend modifying NWN's Action Item regarding Resource Additions and Changes to the following:

2. Resource Additions and Changes.

   2.1 Acquire resources in the near-term consistent with meeting the Base Case firm sales load forecast.

      a. Recall 30,000/day of Mist storage capacity from the interstate storage account effective May 2015 to serve the core customer needs reflected in the Base Case load forecast.
      b. ~~Complete Clark County distribution projects to address Vancouver load center needs — estimated timing of projects is over the next five years with an estimated total capital cost of $25 million.~~
      c. ~~Proceed with the Newport refurbishment project and continue investigating Portland Gasco refurbishment alternatives. Estimated timing of Newport refurbishment is over next three years at an estimated cost of $25 million.~~
      d. Continue the pre-construction phase of the South Salem Feeder Project (e.g., studies, permitting, etc.) and ~~Construct the South Salem Feeder to serve load growth in the Salem area – estimated timing is to begin permitting in 2015 with an in-service date in 2019; estimated cost of $25 million.~~ conduct a Request for Proposal (RFP) for Recallable Agreements in the Salem load center. Provide the Commission with the results of additional analysis (e.g., results of RFP, accelerated DSM analysis, future load growth specific to the Salem load center) related to the South Salem Feeder prior to moving beyond the pre-construction phase of the project.

NWN Action Item 3

3. *Demand-Side Resources and Environmental Considerations*

   3.1 Explore assessing a premium value to account for any natural gas price volatility hedging value associated with DSM energy savings.

   3.2 Follow Oregon Docket No. UM 1622 and revise annual DSM targets as needed in accordance with any changes to the program resulting from Energy Trust requested investigation into the exceptions to the cost effectiveness guidelines.

   3.3 Monitor the implications of EPA regulation 111(d) on future coal plant retirements and the consequential impact of natural gas supply prices.

Staff Final Comments: Demand-Side Resources and Avoided Cost Determination

In NWN's reply comments, it proposes a new action item which states that:

> Consistent with the methodology presented in Chapter 4, NW Natural will ensure Energy Trust has sufficient public purpose charge funding to acquire the therm savings identified and approved by the Energy Trust's board of approximately 5.2 million therms in 2015 and 5.4 million therms in 2016.

A footnote to this action item explains that the above targets, which were approved by Energy Trust's Board, are the IRP targets updated with more current market information, including the extension of the non-cost effective measures investigated in UM 1622 until April 30, 2015. These energy efficiency targets in the new action item are higher than those originally proposed in NWN's IRP.

Specific targets for 2015 and 2016 were not included in NWN's original IRP document. [6] However, in response to Staff's data request number 7, NWN indicated that the original IRP assumed savings targets of 4.6 million therms and 3.9 million therms for 2015 and 2016, respectively. Based on updated market information and resolution of Docket UM 1622, these targets have now been increased from 4.6 to 5.2 million therms for 2015 and from 3.9 to 5.4 million therms for 2016 in the new action item. Staff supports this new action item.

Staff recommends that the proposed new Action Item above replace the Company's proposed Action Items 3.2 and 5.6 which state:

[6] The original IRP only includes cumulative savings for 2018 and 2033, Page 4.1 of the IRP states the Company can achieve a DSM potential of 20.5 million therms by 2018 and over 47.7 million therms by 2033 in its Oregon service territory.

3.2 Follow Oregon Docket No. UM 1622 and revise annual DSM targets as needed in accordance with any changes to the program resulting from Energy Trust requested investigation into the exceptions to cost effectiveness guidelines.

5.6 Continue acquiring cost effective therm savings through energy efficiency programs administered by Energy Trust of Oregon.

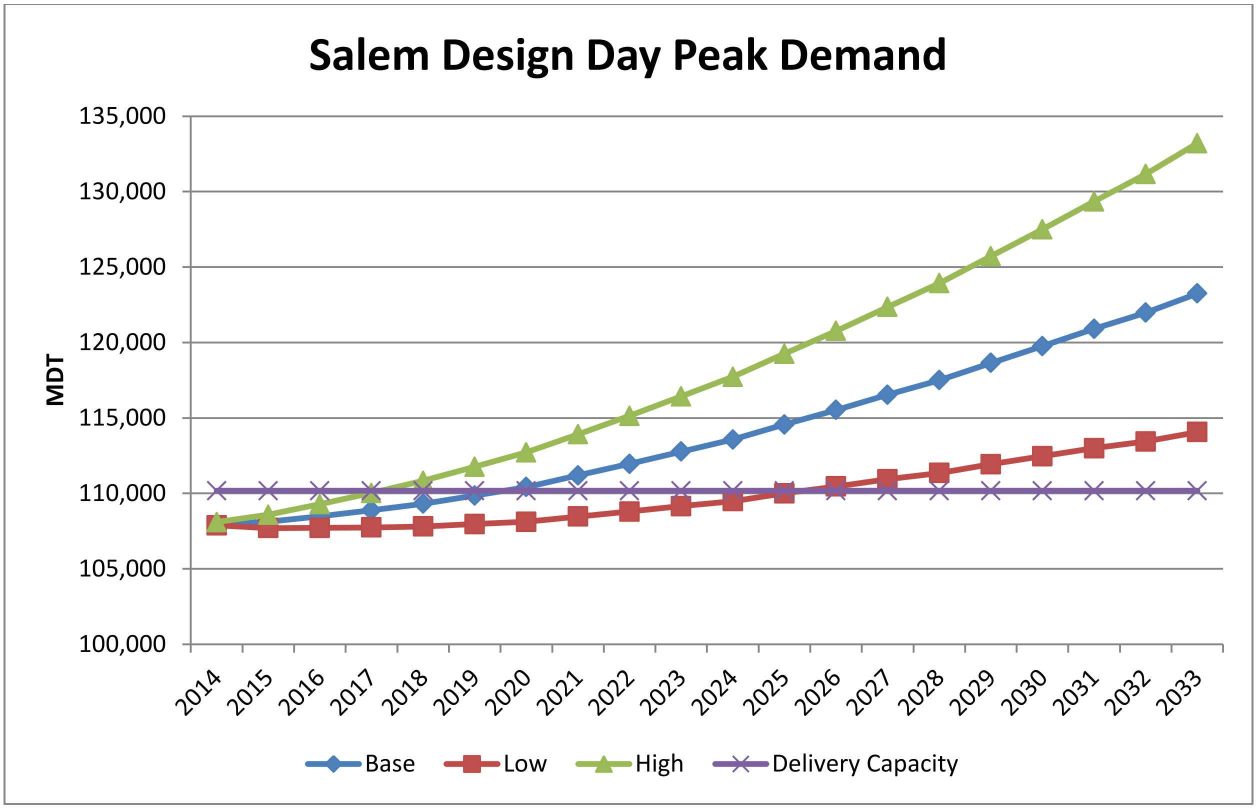
Staff recommends the following Action Item 3.1 be maintained:

*3.*1 Explore assessing a premium value to account for any natural gas price volatility hedging value associated with DSM energy savings.

Staff is currently working with NWN and parties on development of this hedge value or premium value of energy efficiency. Staff supports NWN providing updated Energy Trust-generated DSM annual savings targets with the Company's Annual IRP Update because at that time the Energy Trust will be able to model the savings potential using the updated resource potential and measure information, updated avoided costs, and any program changes due to the proposal in Docket No. UM 1622 to analyze the incentive cap. A placeholder hedge value may be in place at that time as well.

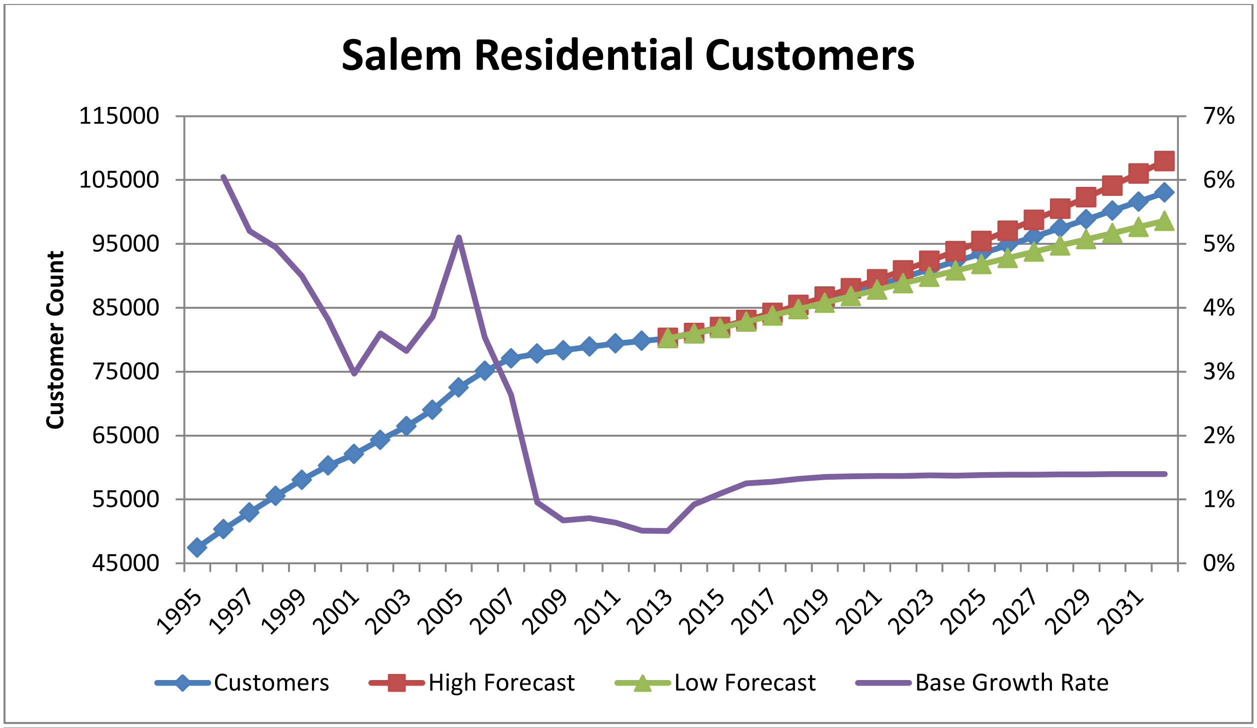
At the Special Public Meeting on November 4, 2014, the Commission requested that the Company look at an accelerated DSM alternative for the Salem area and to assess the impact of that alternative on the need for and timing of the proposed South Salem Feeder, which could potentially defer a specific major capital project, changing the cost effectiveness calculus for energy efficiency measures in the specific area where the major capital improvement investment could be deferred. The Commission was particularly interested in accelerating conservation measures that would reduce peak winter heating loads. Staff submitted a series of data requests to the Company asking how much Salem DSM could be accelerated and whether or not that acceleration would be sufficient to cost effectively delay the Salem feeder project.

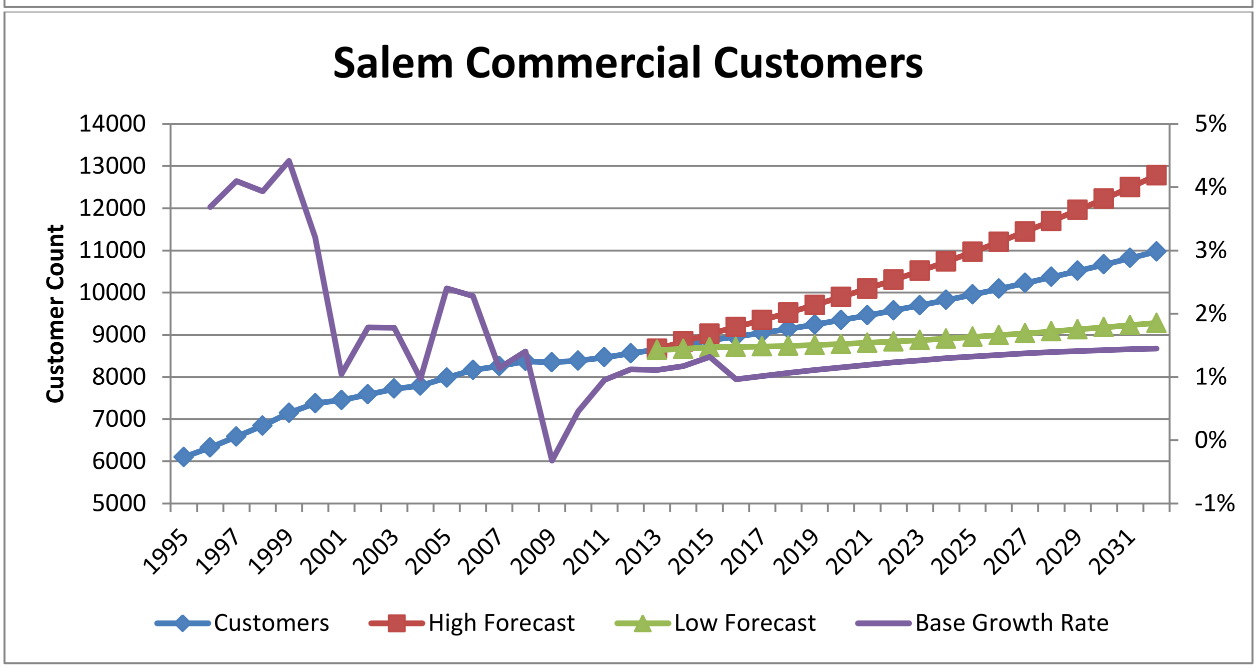
Staff sent a data request inquiring about the Company's natural gas delivery capacity to Salem along with base, low, and high demand forecasts. The figure below shows the result.



As the figure above demonstrates, base case or business as usual demand is projected to exceed delivery capacity in 2020. NWN's IRP shows the South Salem Feeder in place in 2019. In the high peak day forecast, Salem capacity is exceeded in 2018, while in the low projection, the Salem feeder capacity is exceeded in 2026.

The Commission also asked the Company to provide historical numbers for Salem sales demand. The following figures show historical and projected numbers of residential and commercial customers.





In response to the Commission's request and Staff's data request, NWN had Energy Trust study how they could increase DSM in the Salem area. Energy Trust built a resource assessment model using statewide average values for housing and building stock characteristics in different parts of the state. The Energy Trust estimated that the total achievable resource potential in the Salem area by taking the percentage total gas load represented by that area, compared to the whole state, and applying that percentage to the total gas savings potential for the whole state. The percentage of total gas load represented by the Salem area was provided by NWN and contained sector level granularity.

The Energy Trust estimated the total achievable gas savings for the geographic area in question under five different resource acquisition 'scenarios' that represent a range of resource acquisition rates and cost-effectiveness thresholds from slightly more aggressive DSM than the base case deployment to deploying all known potential DSM measures and programs as quickly as feasible. The Energy Trust included a 20 percent cost adder for all incremental energy efficiency above the base case to account for the difficulty and added cost of accelerating acquisition. The following five scenarios were considered:

Scenario 1 – Base Deployment

- Represents the base deployment originally submitted in 2013 IRP, prorated to Salem using the percent of load methodology.
- Only cost effective measures deployed - no UM 1622 exceptions.

Scenario 2 – Limited Measure Acceleration

- Base deployment plus UM 1622 exceptions.
- Accelerated deployment of a limited set of cost-effective measures that are the most easy to speed up adoption of, such as residential showerheads, commercial showerheads, and industrial power burners.
- For accelerated measures, it is assumed that 25 percent of remaining achievable potential is acquired in each of the years 2015-2018.[7]

Scenario 3 – Expanded Measure Acceleration

- Includes all the same measures as scenario 2,
- Includes a wider set of measures where the resource acquisition is accelerated beyond those included in scenario 2, including residential ceiling insulation and certain cost-effective commercial roof insulation applications.
- For accelerated measures, it is assumed that 25 percent of remaining achievable potential is acquired in each of the years 2015-2018.[8]

Scenario 4 – Limited Measure Acceleration regardless of Cost-effectiveness

- Removes cost effectiveness constraint on measures to be included in the total resource potential estimate.

[7] This is an aggressive acceleration scenario that Energy Trust has little to not experience with in the market, so it is difficult for them to judge whether or not the 20 percent cost adder for measure acceleration is accurate.

[8] This is an aggressive acceleration scenario that Energy Trust has little to not experience with in the market, so it is difficult for them to judge whether or not the 20 percent cost adder for measure acceleration is accurate.

- Accelerates the same set of measures accelerated in Scenario 2 (i.e., residential showerheads, commercial showerheads, and industrial power burners)

Scenario 5 – Expanded Measure Acceleration regardless of Cost-effectiveness

- Removes cost effectiveness constraint on measures to be included in the total resource potential estimate.
- Accelerates the same set of measures as scenario 3, which adds residential ceiling insulation and certain cost-effective commercial roof insulation applications to base measures accelerated.
- Represents the upper limit on amount of resources that could theoretically be acquired over the relevant time period using commercially viable energy efficiency technologies.

Using the same methodology as used in the 2014 IRP, NWN analyzed the impact of each DSM scenario with respect to the South Salem Feeder timeline and total costs over the planning horizon. The results are shown in the table below, from NWN's supplemental response to Staff data request number 95.

Scenario	South Salem Feeder Date	Net present value revenue requirement ($000)
Base	**2019**	**$6,708,897**
1	2020	+$5,744
2	2020	+$5,683
3	2024	+$14,483
4	2024	+$14,495

Scenarios 1 and 2 delayed the South Salem Feeder project by one year from its planned 2019 availability and resulted in an increase in total net present value revenue requirement (NPVRR) of $5.7 million. Under scenarios 3 and 4 NWN would be able to delay the Salem feeder project by five years until 2024, but the NPVRR would be increased by approximately $14.5 million. Based on these results, NWN concludes that neither accelerated DSM nor added measures are cost-effective alternatives to constructing the South Salem Feeder in 2019.

Staff notes that there were some very broad assumptions used in the South Salem Feeder analysis described above. Of particular note is that statewide average values for housing and building stock characteristics were used. The Energy Trust indicated to Staff that given three to six months, it could perform a more detailed study specific to Salem that would provide more detailed information about the actual resource potential given buildings and businesses in the area.

Staff sent a data request to the Company asking about the specific timing of the Salem feeder project. In the Company's response to Staff Data Request 102, the following schedule for the South Salem Feeder is described:

- 2015 – Engineering studies to determine feasible route
- 2015/2016 – Preliminary technical geotechnical, environmental, surveying, land acquisition and archeological studies
- 2016 – Select the final pipeline route
- 2016/2017 – Full investigation and final design and land acquisition
- 2017 – Begin purchasing materials
- 2017 – Issue a Request for Proposals and select contractor
- 2017 – Begin construction

Given this schedule and given the potential for a more detailed look at the Salem area to reveal specific savings opportunities and costs, it would be worthwhile for the Energy Trust to look more deeply at the potential for accelerated savings in Salem and the potential cost, prior to moving beyond the pre-construction phase of the South Salem Feeder project. Staff is interested in understanding the extent to which large bypass customers exist within the service area of the proposed Salem feeder and the amount and cost of accelerating DSM for them and other large commercial/industrial customers in the area. Staff is also interested in the potential for recall agreements to be used to delay the Salem feeder as described as a potential in the Company's response to Staff data request 17.[9]

DSM Summary

Staff will recommend that the Commission acknowledge NWN's new proposed action item which states:

> Consistent with the methodology presented in Chapter 4, NW Natural will ensure Energy Trust has sufficient public purpose charge funding to acquire the therm savings identified and approved by the Energy Trust's board of approximately 5.2 million therms in 2015 and 5.4 million therms in 2016.

Staff will recommend the above action item replace the Company's originally proposed action items 3.2 and 5.6 which read:

> 3.2 Follow Oregon Docket No. UM 1622 and revise annual DSM targets as needed in accordance with any changes to the program resulting from Energy Trust requested investigation into the exceptions to cost effectiveness guidelines.

[9] NWN says it intends to investigate the potential for instituting recall agreements with the 55 Salem customers in rate schedule 31 and 32, who are eligible. NWN says these customers collectively have 4,734 Dth in maximum daily volumes under contract. If hypothetically, all of these customers agreed to recall agreements, it would eliminate the Salem shortfall until 2025. If 10 percent of these customers agreed to recall agreements, it would eliminate the Salem shortfall for one year.

5.6 Continue acquiring cost effective therm savings through energy efficiency programs administered by Energy Trust of Oregon.

Staff also recommends that the Commission acknowledge action item 3.1 which states:

3.1 Explore assessing a premium value to account for any natural gas price volatility hedging value associated with DSM energy savings.

Staff recommends that the Commission give NWN and the Energy Trust more time to explore non-pipe options to the South Salem Feeder before deciding on acknowledgement of the project.

NWN Action Item 4

4. Hedging

4.1 Increase the Company's long-term hedged position of gas requirements from the current level of approximately 10% up to 25% consistent with the recommendation of the Company's consultant. NW Natural will propose specific long-term hedging parameters for Commission and stakeholder review prior to June 30, 2015.

Staff Final Comments Hedging

Staff indicated in its initial comments that consideration should be given to a modified hedging strategy that provides the right incentives for the Company, but at the same time protects its customers from gas price volatility and unreasonable losses.

In NWN's reply comments, the Company proposes additional time to review its hedging strategy, which currently proposes increasing its long-term hedged position from approximately 10 percent of its portfolio to 25 percent of its portfolio. NWN's proposal includes two workshops, first on March 15, 2015, then on May 15, 2015, to discuss the Company's specific long-term hedging parameters, which would result in a Commission decision by June 30, 2015.

At the Special Public Meeting on November 4, 2014, the Commission stated[10] that increasing NWN's long-term hedging position from 10 percent to 25 percent of its portfolio is an important issue. The Commission indicated that consideration should be given to investigating the hedging issue separately allowing parties the time needed for an in-depth review.

[10] The audio from the special public meeting on November 4, 2014, can be reviewed using the following link: http://apps.puc.state.or.us/audio/110414-lc60/1009.mp3

Staff appreciates NWN's efforts to extend the review period of its hedging strategy and willingness to provide additional information regarding the parameters of its hedging plan. However, the Company's proposal does not allow enough time to investigate this complex and important issue. NWN's hedging strategy has resulted in substantial losses for its customers for the period 2009 to 2014.Therefore, Staff recommends that hedging be bifurcated from this IRP and be reviewed separately. CUB's opening comments also recommend that additional time is needed for review of this issue.

Additional Issues

Staff Comments: Supply-Side Resources

Supply Diversity and Risk Mitigation Practices

IRP Guideline 13

Staff's Initial Comments observed an inadequate recognition of the IRP Guideline 13 Resource Acquisition requirement. While Staff's Initial Comments were directed to gas supply and transportation bidding practices, the comment applies to all resource decisions. The context for this requirement is expressed in the Guideline 13 wording for an electric utility, as follows:

> *a. An electric utility should, in its IRP:*
> *Identify its proposed acquisition strategy for each resource in its action plan.*

In its Reply Comments, NWN stated its belief that Guideline 13 was developed in full recognition that each local distribution company (LDC) engages with Staff in the annual PGA process. NWN continued with a statement that Staff's comments have the potential for creating requirements that would be duplicative of the PGA process. Lastly, NWN noted that previous IRPs had not been subjected to Staff's current application of the Guideline 13 Resource Acquisition requirement.

Staff agrees that Guideline 13 was likely developed in full recognition that each LDC engages with Staff in the annual PGA process. However, Staff does not agree that Guideline 13 was developed considering the PGA process would also address resource acquisitions. Instead, Staff contends that the IRP and the PGA are distinctly separate processes with distinctly separate goals. The IRP, not the PGA, is the correct process for vetting resource acquisition decisions, including the decision process. Indeed, the Commission expressed that the goal of least-cost planning is for utility resource plans to identify resources that provide the best mix of cost and risk.[11] Furthermore, Guideline 13 should be interpreted in agreement with Guideline 1 (a) which requires that "[a]ll resources must be evaluated on a consistent and comparable basis." The PGA is the process where the result of the vetted resource acquisition decisions and process is

[11] Order No. 07-002 at page 1.

reviewed. Therefore, Staff continues to observe an inadequate recognition by NWN of the Guideline 13 Resource Acquisition requirement.

Considering several more examples[12] in NWN's IRP of an inadequate recognition of the Guideline 13 requirement, these related to resource acquisitions, Staff reiterates its Initial Comments that:

- The IRP is to provide sufficient detail to allow Staff and participants to do a thorough review of the purchasing, hedging and risk management plans, policies and strategies; and

- The IRP, not the PGA, is the correct proceeding for vetting resource acquisition decisions, including the decision process. The PGA is the proceeding where the result of the vetted resource acquisition decisions and process is reviewed.

Regardless of how past IRPs have been treated with regard to Guideline 13 Resource Acquisition requirement, Staff recommends that the Commission reinforce that Staff's view of the Guideline 13 requirement in its Order on this IRP.

Staff Comments: Linear Programming and Risk Analysis

In its initial comments, Staff noted that the process of developing and comparing prospective supply portfolios is complicated because of supply dependency on interstate pipeline companies whose future expansions are something which NWN can influence, but cannot control. In addition, Staff conceded that the conventional approach to risk evaluation for electric utilities does not work as well for a natural gas utility. Lastly, Staff noted its major conclusion regarding the fulfillment of the IRP Compliance Requirement was that the plan include "two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes." While NWN provided cost estimates for various portfolios based upon a certain weather standard, it did not provide 95 percent (or other) upper limits for the present value revenue requirement (PVRR), taking into account both weather variability and gas purchase price uncertainties.

NWN's reply comments contend that its portfolio evaluation adheres to the intent of the IRP Guideline by accounting for a possible divergence in basis differential at commodity purchasing hubs and the range of new interstate pipeline rates. NWN stated its belief

[12] IRP page 3.18 D. "This agreement is only in place during the December 2014-February 2015 period and is discussed in more detail in the Company's current PGA filing.", IRP page 3.18 E. "While commodity purchase costs will go up because more gas will be purchased at Sumas rather than Station 2, the reduction in pipeline demand charges will be more than enough to produce net cost savings for customers. Such an analysis has been included in the Company's current PGA filing.", and IRP page 3.33 A. "The focus of the GAP is on the forthcoming gas contracting year which runs from November through the following October, which also coincides with the upcoming PGA "tracker" year. This focus extends for up to two additional contracting years for multi-year hedging considerations. Longer-term resources plans and hedging targets are the focus of the IRP and hence are not covered in the GAP, except of course to assure consistency in the transition from near term to longer term planning decisions."

these are the greatest risks to the resource portfolio selection. The remainder of NWN's comments focused on gas price issues.

Staff observes that the analysis process for selection of a resource portfolio with the best combination of expected costs and associated risks and uncertainties is outlined in IRP Guidelines 1.b.2. and 1.c., as well as Guideline 4.i., j., k. and l. While the analysis process is not prescribed, it is outlined and applied to include, in order, distinct phases: deterministic; and stochastic. In addition, sensitivity testing may also be performed. These analysis phases include a deterministic analysis, a stochastic analysis and a sensitivity testing to test for conditions not well represented in the deterministic and stochastic analysis.

Staff contends that the analysis NWN contends adheres to the intent of the IRP Guideline[13] is sensitivity testing. Still absent is the required stochastic analysis to calculate 95 percent (or other) upper limits for the PVRR, taking into account both weather variability and gas purchase price uncertainties, simultaneously.

Finally, while NWN's reply comments put focus on gas price issues, Staff contends that the portfolio analysis outlined in the IRP Guidelines is not intended to model shifts in basis differential at purchasing hubs or other gas market dynamics. Instead, portfolio analysis is to use a range of gas price curves individually in the deterministic phase, randomly in the stochastic phase, and then in sensitivity testing.

For future IRPs, Staff recommends that the Commission note that the above portfolio analysis phases are intended in IRP Guidelines 1.b.2. and 1.c., as well as Guideline 4.i., j., k. and l. to meet the primary goal of selecting a resource portfolio with the best combination of expected costs and associated risks and uncertainties for the utility and its customers (Guideline 1.c.). In addition, Staff recommends that the Commission direct NWN to perform in its 2016 IRP stochastic analysis calculating the 95 percent (or other) upper limits for alternate resource portfolio PVRRs, taking into account both weather variability and gas purchase price uncertainties.

Energy Policies and Environmental Considerations

In Staff's initial comments regarding Guideline 8 (Environmental Costs) that requires utilities to conduct a time profile of CO_2 compliance requirements and to conduct an "analysis that recognizes significant and important upstream emissions that would likely have a significant impact on its resource decisions," Staff stated that it is concerned that all of the climate change risks and opportunities beyond the immediate regulatory effects of EPA's 111 (d) rule are not currently accounted for in the planning cycle. Additionally, Staff stated that it is time for NWN to begin exploring how to analyze climate change risks and opportunities.

[13] By accounting for a possible divergence in basis differential at commodity purchasing hubs and the range of new interstate pipeline rates.

In its Reply Comments, NWN stated that the Company "assessed the impact of alternative regulatory compliance futures on its resource requirements, concluding that the primary resource planning outcome in the highest carbon price scenario is to delay implementation of two resource projects."[14] NWN disagreed with Staff's characterization that it is time for NWN to begin exploring how to analyze climate change risks and opportunities.

Staff appreciates that NWN considered the impact of high carbon tax on its resource acquisition. However, that consideration of a high carbon tax scenario may not be sufficient to account for the impacts of all the climate change risks and opportunities on the Company's resource additions. Therefore, Staff recommends that the Company and participants begin these discussions as part of NWN's next IRP process.

Conclusion

Staff will recommend Commission acknowledgement of NWN's 2014 IRP with both modified and with additional action items to the Company's current proposed Action Plan.

This concludes Staff's final comments.

Dated at Salem, Oregon, this 15th day of January, 2015

Lisa Gorsuch

Lisa Gorsuch
Senior Utility Analyst
Energy Resources & Planning

[14] NWN's Reply Comments, page 15.

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. *All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*

- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*

- *Consistent assumptions and methods should be used for evaluation of all resources.*

- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. *Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*

    1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

    2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and* *associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

    1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

    2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

Guideline 2: Procedural Requirements.

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

Guideline 3: Plan Filing, Review, and Updates.

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*

- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*

- *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

f. *Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

g. *Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

h. *Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

i. *Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

j. *Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

k. *Analysis of the uncertainties associated with each portfolio evaluated;*

l. *Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

m. *Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

n. *An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. *An electric utility should, in its IRP:*

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

CERTIFICATE OF SERVICE

LC 60

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 15th day of January, 2015 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
3930 Fairview Industrial Drive SE
Salem, Oregon 97302
Telephone: (503) 378-5763

EDWARD FINKLEA EXECUTIVE DIRECTIOR	326 FIFTH ST LAKE OSWEGO OR 97034 efinklea@nwigu.org
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD	
TOMMY A BROOKS	1001 SW FIFTH AVE, STE 2000 PORTLAND OR 97204-1136 tbrooks@cablehuston.com
CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP	
CHAD M STOKES	1001 SW 5TH - STE 2000 PORTLAND OR 97204-1136 cstokes@cablehuston.com
CITIZENS' UTILITY BOARD OF OREGON	
OPUC DOCKETS	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
ROBERT JENKS **(C)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
NORTHWEST NATURAL	
JENNIFER GROSS **(C)**	220 NW 2ND AVENUE PORTLAND OR 97209 jennifer.gross@nwnatural.com
TAMY LINVER **(C)**	220 NW SECOND AVE PORTLAND OR 97209 tsl@nwnatural.com
MARK R THOMPSON **(C)**	220 NW 2ND AVE PORTLAND OR 97209 mark.thompson@nwnatural.com
PORTLAND GENERAL ELECTRIC	
PATRICK G HAGER	121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com; patrick.hager@pgn.com
V. DENISE SAUNDERS	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com
PUBLIC UTILITY COMMISSION OF OREGON	
LISA GORSUCH **(C)**	PO BOX 1088 SALEM OR 97308-1088 lisa.gorsuch@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
JASON W JONES **(C)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us