ORIGINAL
N.H.P.U.C. Case No. DG-06-105
Exhibit No. 4
Witness Panel

# 2007 Natural Gas Integrated Resource Plan

December 31, 2007

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# 1. EXECUTIVE SUMMARY

Avista's 2007 Natural Gas Integrated Resource Plan (IRP) identifies a strategic natural gas resource portfolio that meets future demand requirements. The foundation for integrated resource planning is the demand planning criteria utilized for the development of demand forecasts. The formal exercise of bringing together forecasts of customer demand with comprehensive analyses of resource options, including supply-side and demand-side measures, is valuable to the company, its customers and regulatory commissions for long-range planning.

Avista submits an IRP to the public utility commissions in Idaho, Washington and Oregon every two years as required by state regulation[1]. The company has a statutory obligation to provide reliable natural gas service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We regard the IRP as a means for identifying and evaluating various resource options and as a process to establish a plan of action for resource decisions. Through ongoing and evolving investigation and research, we may determine that alternative resources are more cost-effective than those resources selected in this IRP. We will continue to review and refine our knowledge of resource options and will act to secure these least-cost options when appropriate.

The IRP identifies and establishes an action plan to steer the company toward the least-cost method of providing service to our natural gas customers. There are a number of factors that must be considered within the context of least-cost, including an assessment of risks associated with each alternative. Therefore, actions resulting from the IRP process represent risk-adjusted, least-cost results, which we refer to as best cost/risk resources.

Avista's management and stakeholders in the Technical Advisory Committee (TAC) play a key role and have a significant impact in guiding the plan to its conclusions. TAC members include customers, Commission Staff, consumer advocates, academics, utility peers, governmental agencies and other interested parties (a list of TAC members is in Appendix 1.1). The TAC provides important input on modeling, planning assumptions and the general direction of the planning process.

## IRP PROCESS AND STAKEHOLDER INVOLVEMENT

Preparation of the IRP is a coordinated effort by several departments within the company and includes input from Commission Staff, customers and other stakeholders. Topics leading to the development of the IRP include natural gas sales forecasts, demand-side management, distribution planning, supply-side resources and computer modeling tools, resulting in an integrated resource portfolio.

[1] In Washington, IRP requirements are outlined in WAC 480-90-238 entitled "Integrated Resource Planning." In Idaho, the IRP requirements are outlined in Case No.GNR-G-93-2, Order No. 25342. In Oregon, the IRP requirements are outlined in Order No. 89-507, 07-002 and UM1056. Chapter 6 of this document details these requirements.

**Table 6.7 - Annual Demand, Annual Average Demand and Peak Day Demand Served by Demand-Side Management**

| Case | Gas Year | Annual Klamath DSM (MDth) | Daily Klamath DSM (MDth/day) | Peak Day Klamath DSM (MDth/day) | Annual La Grande DSM (MDth) | Daily La Grande DSM (MDth/day) | Peak Day La Grande DSM (MDth/day) | Annual Medford DSM (MDth) | Daily Medford DSM (MDth/day) | Peak Day Medford DSM (MDth/day) | Annual Roseburg DSM (MDth) | Daily Roseburg DSM (MDth/day) | Peak Day Roseburg DSM (MDth/day) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Expected | 2007-2008 | 3.589 | 0.010 | 0.030 | 1.695 | 0.005 | 0.010 | 11.117 | 0.030 | 0.080 | 3.112 | 0.009 | 0.020 |
| Expected | 2008-2009 | 7.408 | 0.020 | 0.050 | 3.381 | 0.009 | 0.020 | 22.142 | 0.060 | 0.170 | 6.202 | 0.017 | 0.040 |
| Expected | 2009-2010 | 11.112 | 0.030 | 0.080 | 5.072 | 0.014 | 0.040 | 33.214 | 0.091 | 0.250 | 9.303 | 0.025 | 0.060 |
| Expected | 2010-2011 | 14.816 | 0.041 | 0.100 | 7.044 | 0.019 | 0.050 | 44.285 | 0.121 | 0.330 | 12.404 | 0.034 | 0.080 |
| Expected | 2011-2012 | 18.580 | 0.051 | 0.130 | 8.829 | 0.024 | 0.060 | 55.584 | 0.152 | 0.410 | 15.561 | 0.043 | 0.100 |
| Expected | 2012-2013 | 22.223 | 0.061 | 0.150 | 10.566 | 0.029 | 0.080 | 66.427 | 0.182 | 0.500 | 18.607 | 0.051 | 0.120 |
| Expected | 2013-2014 | 25.927 | 0.071 | 0.180 | 12.327 | 0.034 | 0.090 | 77.644 | 0.213 | 0.580 | 21.708 | 0.059 | 0.150 |
| Expected | 2014-2015 | 29.789 | 0.081 | 0.210 | 14.695 | 0.040 | 0.110 | 92.751 | 0.253 | 0.680 | 25.609 | 0.070 | 0.170 |
| Expected | 2015-2016 | 32.318 | 0.089 | 0.230 | 15.868 | 0.043 | 0.120 | 104.962 | 0.288 | 0.760 | 27.237 | 0.075 | 0.180 |
| Expected | 2016-2017 | 34.645 | 0.095 | 0.250 | 16.937 | 0.046 | 0.130 | 110.941 | 0.304 | 0.830 | 28.610 | 0.078 | 0.200 |
| Expected | 2017-2018 | 37.091 | 0.101 | 0.270 | 18.063 | 0.049 | 0.140 | 117.471 | 0.321 | 0.900 | 30.109 | 0.082 | 0.220 |
| Expected | 2018-2019 | 39.481 | 0.108 | 0.290 | 19.181 | 0.053 | 0.150 | 125.588 | 0.344 | 0.990 | 31.605 | 0.087 | 0.230 |
| Expected | 2019-2020 | 42.011 | 0.115 | 0.320 | 20.359 | 0.056 | 0.160 | 132.596 | 0.363 | 1.060 | 33.179 | 0.091 | 0.250 |
| Expected | 2020-2021 | 44.125 | 0.121 | 0.340 | 21.356 | 0.058 | 0.170 | 137.980 | 0.377 | 1.130 | 35.662 | 0.097 | 0.280 |
| Expected | 2021-2022 | 48.821 | 0.134 | 0.380 | 22.407 | 0.061 | 0.180 | 143.930 | 0.394 | 1.200 | 37.075 | 0.102 | 0.300 |
| Expected | 2022-2023 | 51.104 | 0.140 | 0.410 | 23.383 | 0.064 | 0.190 | 149.423 | 0.409 | 1.270 | 38.385 | 0.105 | 0.320 |
| Expected | 2023-2024 | 53.570 | 0.147 | 0.430 | 24.424 | 0.067 | 0.210 | 155.608 | 0.426 | 1.340 | 39.853 | 0.109 | 0.330 |
| Expected | 2024-2025 | 55.672 | 0.152 | 0.450 | 25.334 | 0.069 | 0.220 | 160.410 | 0.438 | 1.410 | 41.006 | 0.112 | 0.350 |
| Expected | 2025-2026 | 57.956 | 0.159 | 0.480 | 26.309 | 0.072 | 0.230 | 165.904 | 0.455 | 1.480 | 42.316 | 0.116 | 0.370 |
| Expected | 2026-2027 | 60.221 | 0.165 | 0.500 | 27.280 | 0.075 | 0.240 | 171.243 | 0.469 | 1.550 | 43.603 | 0.119 | 0.380 |
| Expected | 2027-2028 | 62.673 | 0.171 | 0.520 | 28.324 | 0.077 | 0.250 | 183.044 | 0.500 | 1.620 | 45.051 | 0.123 | 0.390 |

| Case | Gas Year | Annual Oregon DSM (MDth) | Daily Oregon DSM (MDth/day) | Peak Day Oregon DSM (MDth/day) | Annual WA/ID DSM (MDth) | Daily WA/ID DSM (MDth/day) | Peak Day WA/ID DSM (MDth/day) | Annual Total System DSM (MDth) | Daily Total System DSM (MDth/day) | Peak Day Total System DSM (MDth/day) |
|---|---|---|---|---|---|---|---|---|---|---|
| Expected | 2007-2008 | 19.513 | 0.053 | 0.140 | 67.664 | 0.185 | 0.470 | 87.177 | 0.239 | 0.610 |
| Expected | 2008-2009 | 39.134 | 0.107 | 0.280 | 134.837 | 0.368 | 0.930 | 173.971 | 0.475 | 1.210 |
| Expected | 2009-2010 | 58.701 | 0.161 | 0.430 | 202.255 | 0.554 | 1.400 | 260.956 | 0.715 | 1.830 |
| Expected | 2010-2011 | 78.549 | 0.215 | 0.560 | 269.674 | 0.739 | 1.860 | 348.223 | 0.954 | 2.420 |
| Expected | 2011-2012 | 98.554 | 0.269 | 0.700 | 338.321 | 0.924 | 2.330 | 436.875 | 1.194 | 3.030 |
| Expected | 2012-2013 | 117.824 | 0.323 | 0.850 | 500.544 | 1.371 | 3.900 | 618.368 | 1.694 | 4.750 |
| Expected | 2013-2014 | 137.606 | 0.377 | 1.000 | 694.854 | 1.904 | 5.770 | 832.461 | 2.281 | 6.770 |
| Expected | 2014-2015 | 162.845 | 0.445 | 1.170 | 881.620 | 2.409 | 7.510 | 1,044.465 | 2.854 | 8.680 |
| Expected | 2015-2016 | 180.385 | 0.494 | 1.290 | 1,020.652 | 2.796 | 8.720 | 1,201.038 | 3.291 | 10.010 |
| Expected | 2016-2017 | 191.134 | 0.524 | 1.410 | 1,155.248 | 3.165 | 9.980 | 1,346.381 | 3.689 | 11.390 |
| Expected | 2017-2018 | 202.734 | 0.554 | 1.530 | 1,232.522 | 3.368 | 10.790 | 1,435.256 | 3.921 | 12.320 |
| Expected | 2018-2019 | 215.855 | 0.591 | 1.660 | 1,309.797 | 3.588 | 11.600 | 1,525.652 | 4.180 | 13.260 |
| Expected | 2019-2020 | 228.145 | 0.625 | 1.790 | 1,392.710 | 3.816 | 12.410 | 1,620.854 | 4.441 | 14.200 |
| Expected | 2020-2021 | 239.124 | 0.653 | 1.920 | 1,464.292 | 4.001 | 13.210 | 1,703.415 | 4.654 | 15.130 |
| Expected | 2021-2022 | 252.232 | 0.691 | 2.060 | 1,541.539 | 4.223 | 14.020 | 1,793.772 | 4.914 | 16.080 |
| Expected | 2022-2023 | 262.296 | 0.719 | 2.190 | 1,617.415 | 4.431 | 14.830 | 1,879.711 | 5.150 | 17.020 |
| Expected | 2023-2024 | 273.454 | 0.749 | 2.310 | 1,700.313 | 4.658 | 15.630 | 1,973.767 | 5.408 | 17.940 |
| Expected | 2024-2025 | 282.422 | 0.772 | 2.430 | 1,762.283 | 4.815 | 16.420 | 2,044.705 | 5.587 | 18.850 |
| Expected | 2025-2026 | 292.485 | 0.801 | 2.560 | 1,831.275 | 5.017 | 17.200 | 2,123.760 | 5.819 | 19.760 |
| Expected | 2026-2027 | 302.348 | 0.828 | 2.670 | 1,900.267 | 5.206 | 17.990 | 2,202.615 | 6.035 | 20.660 |
| Expected | 2027-2028 | 319.092 | 0.872 | 2.780 | 1,956.491 | 5.346 | 18.770 | 2,275.584 | 6.217 | 21.550 |

## REGULATORY REQUIREMENTS

IRP regulatory requirements in Washington, Oregon and Idaho require several key components in our plan. We must demonstrate we have:

- examined a range of demand forecasts;
- examined feasible means of meeting demand including both supply-side and demand-side resources;
- treated supply-side and demand-side resources equally;
- described our long term plan for meeting expected load growth;
- described our plan for resource acquisitions between planning cycles;

  taken planning uncertainties into consideration; and
- involved the public in the planning process

Throughout this document, we have addressed the applicable requirements. Recent rulemaking in Oregon has provided further guidance. Order UM 1056 outlines

13 guidelines where we must demonstrate we have addressed the following areas:

- Substantive requirements
- Procedural guidelines
- Plan filing, review and updates
- Plan components
- Transmission (Transportation)
- Conservation
- Demand Response
- Environmental costs
- Direct access loads
- Multi state utilities
- Reliability
- Distributed generation
- Resource acquisition

Appendix 6.11 lists the specific requirements of the guidelines and describes our compliance.

One area that warrants specific discussion is risk and uncertainty. Our approach in addressing this requirement was to identify the factors that could cause significant deviation from our Expected Case planning conclusions. We employed analytical methods for each of our load forecasting assumptions, including use per customer, weather, customer growth rates and price elasticity.

Inadequate consideration or evaluation of these factors could significantly impair the planning process and its effectiveness. We have modeled High and Low Demand alternatives, incorporated price elasticity considerations, performed preliminary analysis on our peak weather planning standard, run simulations in VectorGas™ and integrated customer growth forecasting in distribution planning with town code refinements.

Beyond these direct modeling considerations, we also considered the consequences of insufficient timelines for resource acquisition or development, cost overruns and siting/permitting risks. Infrastructure outages were also identified as a risk area potentially disrupting plan execution. We are exploring ways to better integrate these types of uncertainties into our planning process.

## ACTION ITEMS

We will refine our specific resource acquisition action plans for Klamath Falls and Medford service areas that address the projected unserved Expected Case demand in 2011-2012 and 2013-2014, respectively. We will monitor timelines, milestones, status and progress reporting, ongoing plan risk assessment and consideration of alternative actions.

### *For Klamath Falls we will:*

- reassess the necessary operational steps and timing (current estimate six months) to acquire the Klamath Falls Lateral;
- monitor actual demand trends to forecasted demand to refine a target date for initiating the purchase of the lateral.

### *For Medford we will:*

- commission a pipeline expansion study from GTN to identify specific costs and issues;
- monitor actual demand trends to forecasted demand to refine the timing of action plan steps;
- assess the impacts of project timing from possible changes in our weather planning standard.

We will reevaluate our current peak day weather planning standard to ascertain if it still provides the best risk-adjusted methodology in evaluating resource planning.

We will meet regularly with Commission Staff members to provide information on market activities, any material changes to risk management programs, and significant changes in assumptions and/or status of company activity related to the IRP or procurement practices.

## Appendix 6.11 Oregon Public Utility Commission IRP Standard and Guidelines

| Guideline Number | escri tion of Req irement | Fulfillment of Requirement |
| --- | --- | --- |
| **Guideline 1: Substantive Requirements** | | |
| 1.a.1 | All resources must be evaluated on a consiste t and comparable basis. | All resource options including Demand side and Supply side are modeled in SENDOUT utilizing the same common assumptions, approach and methodology. |
| 1.a.2 | 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 deman response. | Avista considered a range of resources including demand-side management, distribution system enhancements, interstate pipeline transportation, transport backhauls, and storage options including liquefied natural gas. Chapter 3 and Appendix 6.10 and 6.11 documents Avista's demand-side management resources considered. Chapter 5 and Appendix 6.4 documents supply-side resources. Chapter 6 documents how Avista developed and assessed each of these resources. |
| 1.a.3 | Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling. | Avista considered various combinations of technologies, lead times, in-service dates, durations, and locations. Chapter 6 provides details about the modeling methodology and results. Chapter 5 describes resource attributes and Appendix 6.4 summarizes the resources' lead times, in-service dates and locations. |
| 1.a.4 | Consistent ssum tions and met ods s ould be used for ev luatio of all resourc s. | Appendix 6.1 documents general assumptions used in Avista's SENDOUT® modeling software. All portfolio resources both demand and supply side were evaluated within SENDOUT using the same sets of inputs. |
| 1.a.5 | The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. | Avista applied its after-tax WACC of 4.18% to discount all future resource costs. (See general assumptions at Appendix 6.1) |
| 1 | Risk and uncertainty must be considere Electric utilities only | Not Applicable |
| 1.b.2 | Risk and uncertainty must be considered. Natural gas utilities should consider demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas (GHG) emissions. | After considering the influencers on demand, Avista focused on three scenarios (Table 1.1) for SENDOUT modeling purposes. Demand coe cients were developed for base, shoulder and winter demand (Appendix 2.3) hile peak demand was contemplated through modeling a weather planning standard of the coldest day on record (see heating degree day data in Appendix 6.1).<br><br>Avista evaluated several price forecasts (Figure 6.12) and selected high, medium and low price scenarios for modeling purposes (Figures 6.13 & 6.14) |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | | Avista also ran Monte Carlo simulations using VectorGas™ for price and weather variables to analyze demand sensitivity and resulting resource timing and selection.<br><br>Avista considered potential GHG emissions regulatory compliance costs in Chapter 7. |
| | Utilities should identify in their plans any additional sources of risk and uncertainty. | Avista evaluated additional risks and uncertainties, including the level of DSM achievable potential (Chapter 3). See Chapter 6 for a discussion of the other sources of risk and uncertainty considered but not necessarily modeled for scenario and stochastic risk analysis. |
| 1c | 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. | Gas utilities are different from electric utilities in the number and combinations of resources available. Gas utilities do not have multiple portfolios of resources. Therefore, Avista considers a resource mix of all the supply side and demand side options as our alternative to portfolios. Avista inputs the supply side and demand side measures into SENDOUT® and allows the model to pick a suite of resources. Each scenario has a different resource mix based on the assumptions of the scenario. Avista evaluated cost/risk tradeoffs for each of the scenarios considered. For example, we considered large scale LNG but after considering the lead time, cost, and assessment of the risks we determined it was not a viable option at this time.<br>See Chapter 6 for the company's risk analysis and determination of the preferred resource mix. |
| | 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. | Avista used a 20-year study period for portfolio modeling. Avista contemplated possible costs beyond the planning period that could affect rates including end effects such as infrastructure decommission costs and concluded there were no significant costs reasonably likely to impact rates under different resource selection scenarios. |
| | 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 of 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. | Avista's SENDOUT modeling software utilizes a PVRR cost metric methodology applied to both long and short-lived resources. |
| | To address risk, the plan should include at a minimum: 1) Two measures of PVRR risk: one | Avista, through its VectorGas software, modeled 200 scenarios around varying gas price inputs via Monte Carlo iterations developing a distribution of Total 20 |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | 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. | year cost estimates utilizing SENDOUT's PVRR methodology. Chapter 6 further describes this analysis while Figure 6.15 summarizes this analysis graphically. The variability of costs is plotted against the Expected Case while the scenarios beyond the 95th percentile capture the severity of bad outcomes.<br><br>Chapter 5 discusses Avista's physical and financial hedging methodology. |
| | The utility should explain in its plan how its resource choices appropriately balance cost and risk. | Chapter 6 and Appendix 6.7 summarizes the results of Avista's cost/risk tradeoff analysis, and describes what criteria the company used to determine what resource combinations provide an appropriate balance between cost and risk. |
| 1d | The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | Avista considered current and expected state and federal energy policies in portfolio modeling. Chapter 6 describes the decision process used to derive portfolios, which includes consideration of state resource policy directions. |
| **Guideline 2: Procedural Requirements** | | |
| 2a | The public, including 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. | Chapter 1 provides an overview of the public process and documents the details on public meetings held for the 2007 IRP. |
| 2b | 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 action plan. | The entire IRP, as well as the Technical Advisory Committee process, includes all of the non-confidential information the company used for portfolio evaluation and selection. Avista also provided stakeholders with non-confidential information to support public meeting discussions via email. The draft plan was also made available on Avista's website for public viewing during this period. |
| 2c | The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. | Avista distributed a draft IRP document for external review to TAC members on September 6, 2007 and requested comments by October 31, 2007. The draft plan was also made available on Avista's website for public viewing during this period. |
| **Guideline 3: Plan Filing, Review and Updates** | | |
| 3a | Utility must file an IRP within two years of its previous IRP acknowledgement order. | This Plan complies with this requirement as the 2006 Natural Gas IRP was acknowledged on 9/16/06. |
| 3b | Utility must present the results of its filed plan to | Avista will adhere to this guideline. |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | the Commission at a public meeting prior to the deadline for written public comment. | |
| 3c - g | These guides discuss Commission comments and acknowledgement and the IRP annual update. | Not applicable. |
| **Guideline 4: Plan Components** | | |
| | At a minimum, the plan must include the following elements: | |
| 4a | An explanation of how the utility met each of the substantive and procedural requirements. | The purpose of this table is to comply with this guideline by providing an overview of how Avista met each of the substantive and procedural requirements for a natural gas IRP. |
| 4b | Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions. | Avista developed low, medium and high demand growth forecasts for scenario analysis. Stochastic variability of demand was also captured in the risk analysis. Chapter 2 describes the demand forecast data and Chapter 6 provides the scenario and risk analysis results. Appendix 6.1 details major assumptions. |
| 4c | For electric utilities only | Not Applicable |
| 4d | 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. | This plan complies with the requirement with resource summaries documented in Figure 1.3 (and duplicated in Figure 6.17) for the expected case. Appendix 6.5 summarizes the high and low demand scenarios. Additionally, figure 6.21 shows that the need for resources primarily occurs on and around the peak day. Appendix 6.6 summarizes the high and low case.<br><br>Appendix 6.4 details all the supply side options considered and Appendix 6.9 and 6.10 provides details on the demand side options. Table 6.6 identifies the resources selected by the model for the expected case, and Appendix 6.7 details the resources for the high and low cases. |
| 4e | Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology | Chapter 3 and Appendix 6.9 and 6.10 identify the demand-side resources and costs included in this IRP. Chapter 6 and Appendix 6.4 identify the supply-side resources and costs. |
| 4f | Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs. | Chapter 4 discusses the modeling tools, customer growth forecasting and cost-risk considerations used to maintain and plan a reliable gas delivery system. The Chapter also captures a summary of the reliability analysis process demonstrated at the second TAC meeting.<br><br>Chapter 5 discusses the diversified infrastructure and multiple supply basin approach that acts to mitigate certain reliability risks. |
| 4g | Identification of key assumptions about the future | Appendix 6.1 and Chapter 6 describe the key assumptions and alternative |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | (e.g. fuel prices and environmental compliance costs) and alternative scenarios considered. | scenarios used in this IRP. |
| 4h | 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. | This Plan documents the development and results for resource options evaluated in this IRP (see also Appendix 6.4, 6.9, and 6.10). See also guideline **1c** for further discussion on resource mix alternatives to portfolios. |
| 4i | Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties. | We evaluated our candidate portfolio by performing stochastic analysis using VectorGas™ varying price under 200 different scenarios. Additionally, we test the portfolio of options with the use of SENDOUT® under deterministic scenarios where demand and price vary. For resources selected, we assess other risk factors such as varying lead times required and potential for cost overruns outside of the amounts included in the modeling assumptions. |
| 4j | Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results | Avista's four distinct geographic Oregon service territories limit many resource option synergies which inherently reduces available portfolio options. Feasibility uncertainty, lead time variability and uncertain cost escalation around certain resource options also reduce reasonably viable options. Chapter 6 describes resource options reviewed including discussion on uncertainties in lead times and costs as well as viability and resource availability (e.g. LNG). Appendix 6.4 summarizes the potential resource options identifying investment and variable costs, asset availability and lead time requirements while results of resources selected are identified in Table 6.6 as well as graphically presented in Figure 6.19 for the expect case and Appendix 6.5 for High and Low demand cases. |
| 4k | Analysis of the uncertainties associated with each portfolio evaluated | See the responses to 1.b above. |
| 4l | Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers | Avista evaluated cost/risk tradeoffs for each of the risk analysis portfolios considered.<br>Chapter 6 shows the company's portfolio risk analysis, as well as the process and determination of the preferred portfolio. |
| 4m | 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 | This IRP is presumed to have no inconsistencies. |
| 4n | An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, | Chapter 8 presents the 2008-09 IRP Action Plan with focus on the following areas:<br>• Modeling |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | • Supply/capacity<br>• Forecasting<br>• Regulatory communication<br>• DSM Goals |
| **Guideline 5: Transmission** | | |
| 5 | 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. | Not applicable to Avista's gas utility operations. |
| **Guideline 6: Conservation** | | |
| 6a | Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory. | In our 2006 IRP, Avista retained the services of RLW Analytics to provide data regarding cost, energy-efficiency and technical potential characteristics for DM measures. Using the information from the work of RLW Analytics as a starting point and incorporating any new information, Avista completes a comprehensive assessment of the potential for utility acquisition of energy-efficiency resources into the regularly-scheduled Integrated Resource Planning process. |
| 6b | 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. | In Avista's Action Plan in Chapter 8 we include our conservation programs annual savings targets and reference to Appendix 6.10 for the program's specific details.<br><br>A discussion on the treatment of conservation programs is included in Chapter 3 while selection methodology is documented in Chapter 6. |
| 6c | 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: 1) determine the amount of conservation resources in the best cost/ risk portfolio without regard to any limits on funding of conservation programs; and 2) identify | Not applicable. See the response for 6.b above. |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| | the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | |
| **Guideline 7: Demand Response** | | |
| 7 | 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). | Avista has periodically evaluated conceptual approaches to meeting capacity constraints using demand-response and similar voluntary programs. In the past these have failed to be the most cost-effective response to the constraint.<br><br>Avista is in the process of developing a separate natural gas distribution capacity value as part of the overall avoided cost structure in anticipation of improvements in technology that may allow for the cost-effective use of demand-response options. Avista is currently testing an electric demand-response technology that may be expanded to incorporate natural gas demand-response if suitable equipment can be acquired. |
| **Guideline 8: Environmental Costs** | | |
| 8 | Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for CO2, NOx, SO2, and Hg emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from $0 - $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for NOx, SO2, and Hg, if applicable. | Avista's current direct gas distribution system infrastructure does not result in any CO2, NOx, SO2, or Hg emissions. Upstream gas system infrastructure (pipelines, storage facilities, and gathering systems) do produce CO2 emissions via compressors used to pressurize and move gas throughout the system.<br><br>The Environmental Externalities discussion in Chapter 7 describes our process for addressing these costs. |
| **Guideline 9: Direct Access Loads** | | |
| 9 | An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | Not applicable to Avista's gas utility operations. |
| **Guideline 10: Multi-state utilities** | | |
| 10 | 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. | The 2007 IRP conforms to the multi-state planning approach. |

| Guideline Number | Description of Requirement | Fulfillment of Requirement |
|---|---|---|
| **Guideline 11: Reliability** | | |
| 11 | 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. | Avista analyzes on an integrated basis gas supply, transportation, and storage, along with demand-side resources to reliably meet peak, swing, and base-load system requirements. As stated in Chapter 5, Avista's strategy is to reliably serve our customers on all days, including the peak day. To emphasize our commitment to reliability our assessment of resources favors firm (contractually dependable) resources. Acquisition costs of non-firm resources may be less costly. However, after consideration of risk, these assets do not meet our reliability requirements. |
| **Guideline 12: Distributed Generation** | | |
| 12 | 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. | Not applicable to Avista's gas utility operations. |
| **Guideline 13: Resource Acquisition** | | |
| 13a | An electric utility should: 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. | Not applicable to Avista's gas utility operations. |
| 13b | 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. | This information will be provided following IRP acknowledgment. . |