Avista Corporation
2007 Natural Gas Integrated Resource Plan
Annual Update – Oregon

1. SUMMARY UPDATE

Avista is submitting its annual update as an informational filing. We are not requesting acknowledgement of any changes in proposed actions.

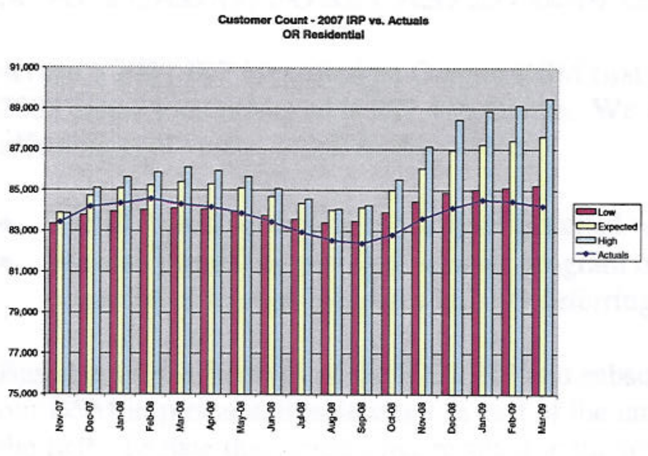
We do not anticipate a significant deviation from our previously acknowledged plan other than to note that the economic downturn has impacted our customer's natural gas usage such that monthly actual demand in our Oregon service territories has trended at (and in some months below) our plan's Low Demand case. We anticipate this weak demand trend will continue given unemployment data and construction weakness in the region. Accordingly, our first identified resource needs in Oregon will likely occur beyond the timetable identified in the Expected case in our plan (winter 2011-12).

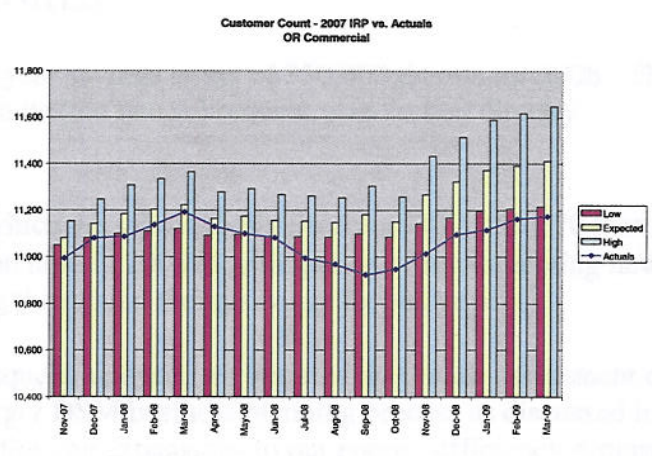
There have been no changes to expiration of any resource contracts nor have we engaged in any significant new supply-side resource acquisitions since plan acknowledgement. Although responsive to the dramatic market changes, we have not made substantial changes to our commodity procurement plan practices as outlined in our acknowledged IRP.

In the following sections, we will further elaborate on what has changed since our plan's acknowledgement, a status update on action plan items, and our insights into emerging planning issues for our next plan. We are pleased to present this information at a Commission public meeting upon request.

2. ACTUAL vs. FORECASTED DEMAND

The following charts compare 2007 IRP forecasts to actual results for customer counts and use per customer (weather normalized) for Oregon residential and commercial customers:





(American Reinvestment and Recovery Act). As we learn more about the direction of these events, we will identify specific utility actions.

4. ACTION PLAN UPDATE

INTEGRATED RESOURCE PORTFOLIO

Action Item:

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; and
- 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 steps; and
- Assess the impacts of project timing from possible changes in our weather planning standard.

Results:

The economic downturn and resultant weak demand we believe will likely delay the projected unserved demand in all of our service territory regions.

Klamath Falls

In 2008, we performed an internal assessment of our standing option to purchase the Klamath Falls lateral from Northwest Pipeline (NWP). This agreement requires relocation of maximum daily quantities (MDQ's) from Klamath Falls to another point (or points) on NWP's system to maintain our total contract demand. We explored numerous possible areas that might benefit from increased capacity. None are currently constrained and our current assessment does not indicate a resource need in the near term. We also explored the potential for new large demand customers with our marketing team which indicated limited near term prospects, especially in light of the current economic environment. Although purchasing the lateral has desirable benefit to our Oregon customers, the lack of actual, anticipated, or prospective need for additional capacity that could fulfill the MDQ relocation requirement (either within the Klamath Falls service territory or elsewhere on the NWP system) does not permit for the purchase of the lateral at this time.

Medford

Demand trends for Medford have tracked to the low end of our IRP forecasts for some time. We therefore have deferred incurring the cost of a formal pipeline expansion study given sufficient time exists to monitor actual demand trends which we will update in our 2009 IRP.

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

Results:
In reevaluating our weather standard we performed the following analyses:

- Sensitivities around one and two HDD weather adjustments;
- VectorGas™ Monte Carlo simulations to analyze probabilities of encountering peak weather;
- Applied confidence levels to review upper limit exposure in conjunction with the regressions performed during our gate station demand and resources work as well as use per customer coefficient development; and
- Examined important qualitative factors around safety and reliability.

While other planning assumptions allow for continuous monitoring for reasonableness and corrective adjustments over time, peak day weather can occur with no warning which severely limits any response adjustments. Significant safety risk, property damage, and inconvenience can occur if actual weather exceeds our peak day weather planning standard. Because there have been limited recent extreme cold weather events, more uncertainty and potential error exists in predicting cold weather usage. The recent actual data we do have on very cold weather events indicate instances when demand has been higher than the projected usage from our regression analysis. Because of these factors, we are maintaining our current "coldest day on record" planning standard for our Expected case.

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

Results:
We have met with Commission Staff several times since our acknowledged IRP to provide an update on various matters. Schedules permitting, we attempt to meet on a quarterly basis.

DEMAND FORECASTING

Action Item:
We will further integrate the VectorGas™ module in our SENDOUT® modeling software to strengthen our ability to analyze the demand impacts under varying weather and price scenarios as well as conduct sensitivity analysis to identify, quantify, and manage risk around these demand influencing components.

Results:
VectorGas™ has provided statistically based analysis in support of our peak day weather standard evaluation. We are evaluating applications for developing statistical modeling and analysis of potential price outcomes for modeling various price elasticity scenarios. We are also exploring potential applications for simulating probabilistic weather outcomes in a possible global warming scenario. We continue to review other applications to employ the VectorGas™ analytical tool in our upcoming IRP.

Action Item:
We will study ways to further refine our ability to model demand by region. Town code forecasting was the first step in enhancing our demand forecasting. We now want to explore incorporating these town code forecasts into regions for analysis in SENDOUT® especially within the broad Washington/Idaho division to investigate potential resource needs that may materialize earlier than the broader region indicates.

Results:
Town code forecasting continues to be an effective method for developing and monitoring expectations for customer growth rates providing benefits beyond the IRP including corporate budgeting and distribution planning. The use per customer coefficient is the other key driver in determining forecasted demand in SENDOUT®. We have explored several potential methods for developing sub regional use per customer coefficients that enhance predicting reasonable expectations of forecasted demand while reconciling tightly back to actual results with backcasting.

We use linear regression on daily observable temperature/demand data to produce coefficients. Allocations of monthly customer demand by class are applied to our gate station data as necessary given few customers have daily metering. Our attempts to build daily town code level coefficients by customer class from allocations of monthly town code level data have not produced satisfactory results. It appears billing period and cutoff issues are magnified when constructing coefficients with smaller customer groupings. Consequently, unacceptable distortions arise in backcasting to actual demand.

We have been more successful in refining our coefficient development into monthly factors from broader regional data. Using more data points, this method provides improved capturing of the seasonal consumption profile. The regressions on the coldest data points from this method were also used in our reassessment and analysis of our peak day weather standard. Because of the superior backcasting that regional coefficients provide, we will forego subregional/Town code level use per customer coefficient development at this time.

DEMAND-SIDE MANAGEMENT

Action Item:
The IRP analysis has indicated a set of cost-effective measures and acquirable resource potential for a future DSM portfolio. We have established targets for first year energy savings goals for 2008 of 1,425,000 therms in WA/ID and 350,000 therms in Oregon. In 2009 the goals for first-year energy savings are 1,581,000 therms in WA/ID and 300,000 therms in Oregon. The completion of the IRP analysis is the midpoint, not the end point, of a larger reassessment of the DSM resource portfolio. Further evaluation is required to facilitate the development of program plans and to incorporate them into an updated DSM implementation plan. Following detailed investigation of the natural gas efficiency technologies identified as cost-effective resource options, we will incorporate these efforts into the larger Heritage Project ramp-up of Avista's energy-efficiency efforts.

Results:
Oregon DSM energy savings achieved in 2008 totaled 287,476 therms, a shortfall from our 2008 goal of 350,000 therms. Additional detail around this shortfall is discussed in Section 3 of this report, ACTUAL VS. FORECASTED DSM GOALS.

Action Item:
We will file our cost-effectiveness limits (CEL's) based upon the avoided costs derived from this IRP process.

Additionally, we are investigating the applicability of recently completed quantifications of electric distribution capacity, the customer value of risk reduction and greenhouse gas emissions to determine if similar quantifications are possible for our natural gas system.

Results:
CEL's were filed on June 9th 2008 with an effective date of July 1st, 2008.

We reviewed the value components for our electric avoided costs to determine if conceptually there was applicability to our natural gas customers. We have initiated analysis to assess the potential value our customers place on the value of reduced volatility. This work continues. Regarding quantifying the value customers ascribe to reduced distribution capacity and greenhouse gas emissions, we concluded quantifications were not reliably determinable.

SUPPLY SIDE RESOURCES

Action Item:
We will continue to monitor several issues identified in this chapter with respect to commodity, storage and supply resources. These include:

- Tight production/productive capacity;
- Pipeline constraints in our region;
- Pipeline expansions that move volumes away from our region;
- Pipeline cost escalations; and
- Large scale LNG activity.

Results:
Through our various information sources (retainer services, industry publications, seminars, and conversations with industry participants) we monitor ongoing developments on the above items. The following are brief summaries of our current assessments:

- Tight production/productive capacity – The economic downturn has dramatically reversed this previously very tight situation producing significant excess capacity. Massive rig count reduction in response to demand destruction has significant potential to overshoot when demand stabilizes, triggering a return to very tight conditions prompting spikes in prices and volatility.
- Pipeline constraints in our region – Several regional pipeline projects were proposed in early 2008. We monitor their progress and assess how they may fit in our resource strategy. We currently have non binding participation agreements on some of these projects.
- Pipeline expansions that move volumes away from our region – Rockies Express eastward expansion has experienced some delays but will ultimately facilitate more Rockies production to reach east coast markets.
- Pipeline cost escalations – Much lower steel commodity prices and delayed/cancelled projects appear to have reversed the cost escalation trend in the near term.

- Large scale LNG activity – Regional proposed projects continue to be challenged by regional market prices that trade at a discount to other potential markets for LNG as well as complex environmental issues.

Action Item:
We will refine our analysis of acquiring or constructing resource alternatives to improve project cost estimating, assessment of project feasibility issues, determination of project siting issues and risks, and improved accuracy of construction/acquisition lead times. Specifically, we will further study these issues with respect to satellite LNG, company owned LNG, pipeline expansions, distribution system enhancements and storage facility diversification.

We will explore creative, non-traditional resource possibilities to address our needle peaking exposures with emphasis on potential structured transactions (e.g. transportation and storage exchanges) with neighboring utilities and other market participants that leverage existing regional infrastructure as an alternative to incremental infrastructure additions.

Results:
Given likely deferred resource needs, we have deferred any expenditures for formal cost and project feasibility studies. We instead collect information from publicly available sources and informal inquiries. We also have gained insights on expansion rates/costs/timelines from our non binding participation in various proposed interstate pipeline projects. This information provides useful proxies for project costs for use in resource modeling.

Although the easing of regional demand correspondingly eases the urgency for needle peaking solutions in the near term, we continue to evaluate the region's participants and their resources for possible transactions. We have engaged in discussions with a neighboring utility regarding a potential mutual assistance agreement around transport assets with dialogue continuing. We also receive and solicit information on various structured product transactions.

Action Item:
We will continue to assess methods for capturing additional value related to existing storage assets, including methods of optimizing recently recalled releases while implementing its storage strategy of providing balanced storage opportunities. This includes exploring storage diversification options including AECO and Northern California facilities.

Results:
We periodically see solicitations for storage leasing. We evaluate the project economics and consider our resource needs. In some cases, we have placed bids. However, our bids have not been selected. We have entered into a month to month storage agreement at Clay Basin for interruptible service which facilitates daily/short term demand balancing for scheduling. Finally, we continue to engage in intra seasonal optimization tractions as market pricing conditions warrant to capture value for our customers.

Action Item:
We will continue to analyze natural gas procurement practices for strategy enhancing ideas such as basis diversification, storage injection/withdrawal timing and structured products.

Results:
Our annual procurement plan development process undertaken each fall provides a comprehensive assessment of existing and potential new procurement practices and strategies. The result is a targeted but flexible procurement plan that serves as a base to evaluate changing conditions throughout the year and modify strategy and actions as necessary.

Action Item:
Since much of our supply comes from Canadian natural gas exports, the notion that this supply could diminish significantly is of concern. We will continue to monitor the discussion around diminishing Canadian gas exports looking for signals that indicate increased risk of disrupted supply over the 20-year planning horizon.

Results:
We utilize multiple information sources to monitor and track developments on declining Canadian exports including our retainer services, industry news subscriptions, seminars, and market pricing behavior. Historical information from the Energy Information Administration (EIA) indicates a rebound in export volumes in recent months following a decade low volume in June 2008. Lower oil sands production in the face of sharp oil price declines is likely a significant factor in this near term trend reversal. Longer term, we see the oil/gas price relationship as a primary driver of Canadian domestic natural gas demand and correspondingly, export volumes. Significant unconventional gas discoveries in BC have both the potential to reverse export declines with prolific potential production or accelerate export declines if these volumes are diverted to oil sands extraction in a high oil price environment.

In our 2009 IRP, we anticipate including a Canadian exports decline case in our demand sensitivities analysis.

5. ACKNOWLEDGEMENT ORDER UPDATE (Order No. 08-308)

In addition to the above Action Items, Oregon Staff offered the following recommendation in their Staff Report advocating acknowledgement of Avista's IRP:

STAFF RECOMMENDATION:
Staff recommends the Commission acknowledge Avista Utilities' (Avista or the company) 2007 Natural Gas Integrated Resource Plan (IRP or the plan), subject to the following modification to the action plan:

"For its next IRP, Avista will analyze (using SENDOUT® and VectorGas™) realistic alternative world situations in which the company may have to operate during the next 20 years, particularly in light of current, new and proposed state, federal and Canadian energy policies and the ongoing evolution of North American and world natural gas, oil and coal markets."

Results:
For Avista's 2009 IRP process, we have defined a methodology and developed a modeling framework to facilitate flexible modeling of alternative scenarios to be responsive to changing conditions and revised assumptions. The methodology explains our perspective for monitoring regional, continental, and global developments that influence long term resource planning. Our modeling framework includes

templates for modifying a full range of key demand driver assumptions. This approach facilitates sensitivity analysis as well as alternative case development. Our preliminary work has identified six areas for potential further analysis and possible alternative case development which include:

- Weather planning standard;
- Compressed natural gas vehicles;
- Global warming;
- Price elasticity;
- Carbon legislation; and
- Canadian imports decline.

We anticipate reviewing these potential scenarios with our Technical Advisory Committee to solicit feedback and identify additional considerations for preparing a manageable yet comprehensive set of plausible scenarios to analyze potential resource needs.

6. EMERGING PLANNING ISSUES

Economic Uncertainty

The current economic downturn has been dramatic and changed near term trends in economic activity. The potential influence on natural gas demand, DSM, infrastructure developments, commodity prices, credit terms and procurement practices in such an unsettled environment presents many forecasting challenges. Historical relationships may be altered or fundamentally changed. For example, customer changes in natural gas consumption may be driven as much by personal income changes as by natural gas prices. DSM initiatives could be enthusiastically pursued by more customers seeking savings on their energy costs while other customers may forego participation due to personal economic constraints. Tight credit markets, lower demand, and community opposition may see pipeline projects and other infrastructure delayed. Alternatively, much lower labor, materials, and interest costs may prompt accelerated infrastructure investment. Assumptions such as discount rates and inflation rates could vary widely.

In tackling these challenges we will pursue analysis and modeling that not only looks at "what happened?" but also asks "what if?" to understand possible outcomes from uncertain times. We will need to be thorough in exploring a wide range of possibilities while keeping vigilant in not being overly dependent on historical trends that may no longer be representative as well as overly influenced by current outlooks with no historical precedent that have high uncertainty.

Seismic Supply Shifts

Over the last several years strong natural gas demand and diminishing conventional supplies resulted in very tight productive capacity. North American gas production was increasingly constrained by lack of sufficient drilling plays with reasonable extraction costs. Forecasts indicated an increasing dependence on LNG imports to bridge the gap between North American constrained supply and robust demand.

However, 2008 marked a significant inflection point as unconventional gas production (especially shale) accelerated and routinely surpassed previous forecasts. Numerous older shale wells have reached generally steady production levels vs. the continued production declines of conventional wells. This lessens the need for numerous rigs to simply replace the steeper declines of conventional wells.

Technology improvements and newly identified shale plays now indicate significant incremental supply potential with reasonable marginal cost which should be responsive to long-term demand. The main driver of North American production growth is now unconventional gas especially shale gas.

2008 also saw the start of burgeoning supply from international LNG projects which have been at least a half decade in the making. Significant capacity is being added as near term global demand is diminished from the prospects of a lingering global recession. This combined with the unconventional gas production supply surge has resulted in an unprecedented collapse in prices. Although beneficial to end users in the near term, this dramatic volatility and uncertainty will undoubtedly cause long term disruption/interruption in production, pipeline and storage capital investment exacerbating boom/bust cycles in the long term and creating modeling and forecasting challenges.

Climate Change Legislation

Despite the challenging global economic environment, some form of Federal climate change legislation appears likely to pass within the next three years with implications far reaching and long term. A cap and trade structure is the most likely framework for reducing carbon emissions. This complex structure has numerous design issues that must be addressed including emissions target levels, phase in timeframes, methodology for allocation of emissions allowances, availability of offset credits, cost mitigation to customers, and a host of implementation challenges.

By design, this legislation is meant to alter the energy production and consumption landscape. Inherent in this new landscape is significant uncertainty in market behavior and acceptance which can profoundly impact our resource needs. Added carbon mitigation costs may slow or reverse end user adoption of natural gas appliances and applications. Direct use initiatives may stall given significant electric resources (hydro, renewables) will not be burdened with a carbon cost adder. The integration of federal legislation with the regional Western Climate Initiative as well as Oregon's proposed Senate Bill 80 (SB-80) also remains uncertain. These example issues will pose significant modeling and forecasting challenges while the greenhouse gas reduction programs are finalized. To meet these challenges, we will confer with and solicit ideas and feedback from Avista's electric resources team, Avista's Climate Change Committee, and our IRP Technical Advisory Committee.