2004 Integrated Resource Plan

VOLUME II:

Technical Appendix

Northwest Natural Gas Company

March 2005

CHAPTER A: GAS REQUIREMENTS FORECAST

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The starting point for resource planning is forecasting future requirements for gas service. This ensures that resources will be available when needed, and will be acquired at the “least cost.” Useful forecasting thus requires that all factors that might impact future gas requirements, or "loads," be thoroughly considered on a daily, seasonal, and annual basis.

I. OVERVIEW

The forecasting process evaluates the amount of gas needed to serve the company's changing customer base. In order to do this, NW Natural (NW Natural or the company) first identifies the characteristics of its customer base, including the number and types of customers currently served, the number and types of customers that could be served in the future, and the amount and pattern of gas usage that can reasonably be expected by those customers.

The forecast focuses on “core market” customers, a group of customers defined as those customers taking firm service on “sales” rate schedules where the company provides both up stream supply capacity and storage gas capacity, and also provides for the commodity gas itself. Firm “transportation” customers provide for their own upstream capacity and commodity gas, and are not explicitly considered. Similarly the gas requirements of customers served on interruptible rate schedules are not considered because the company does not plan for upstream pipeline capacity or storage capacity to serve these customers. The company does provide commodity gas procurement services for interruptible customers taking sales service.

To assist in the analysis of core market requirements, the company uses two sources of economic and demographic forecasts. To develop forecasts for new construction customer gains and fuel-conversion customer gains, the company relies on the Oregon Office of Economic Analysis, Oregon Economic and Revenue Forecast (OERF, December 2003, available at http://www.oea.das.state.or.us). This forecast provides projections through the year 2011. Residential new construction customer gains are directly tied to the OEA forecast of housing starts. For our Base Case forecast, economic-driver growth rates displayed in the last five years of the Economic and Revenue Forecast are extended through the remaining years of the forecast time horizon (2012 through 2033).

To apportion forecast system growth to the company's operating districts we rely on a proprietary state and county level forecast developed by Woods and Poole Economics, Inc. Here, county level projections of employment and population through the year 2025 provide a basis for determining operating district shares of Oregon and Washington system new construction customer gains. Employment and population shares shown in the last year of the Woods and Poole forecast are extended through 2033, the end date of the company's forecast horizon.

Two departures from the Base Case forecast are considered to place reasonable bounds on the range of forecast outcomes. The High forecast uses the higher growth rates in economic drivers observed since 1990. In a similar fashion, the Low forecast employs the lower economic-driver growth rates observed during the same period. These variations begin in the 2005-06 heating season and continue through the 2011-12 heating seasons. They are then frozen at their 2011-12 levels.

The company uses county-level regional forecasts to derive the share of regional economic and population growth that can be expected to occur in the company's service territory. We then translate that growth into probable numbers of new customers served in new construction market segments.

Beyond new construction customer gains, NW Natural adds in each year the number of customers expected to convert to natural gas from other energy sources. For this purpose we employ a stock depletion model that recognizes the changing number of residential dwellings within reach of our growing distribution system. Probabilities of conversion are applied to a stock of dwellings that grows with system expansions and also declines with the number of conversions experienced in each forecast year. The combination of methods for forecasting customer gains through new construction, and conversions from other fuels, produces a reasonable range of long-term forecasts for customer growth, including cases of relative rapid growth and relative stagnation.

Each new customer brings its own gas usage patterns and levels of use that depend on many factors. Usage patterns differ for new construction customers and conversion customers. These differences are related in large part to the efficiencies of the equipment and number of appliances customers install, the size of dwellings or commercial structures to be space conditioned, when and how the equipment is used, and the environment in which the equipment resides (weatherized vs. non-weatherized).

With these analyses, the company is better prepared to anticipate future changes in customer gas requirements, and is better prepared to plan for the use of existing resources and the appropriate acquisition of new supply resources.

NW Natural's *past* IRP forecasts used five growth scenarios based on the economic and demographic drivers contained in the Northwest Power Planning Council's Northwest Conservation and Electric Power Plan. These cases were identified as High, Medium-High, Medium, Medium-Low, and Low. The High case typically embodied growth rates far higher than any episode experienced historically by the company, while growth rates reflected in the Low growth scenario had not been experienced in the company's modern history. While the Council's 1995 forecast performed well, it has not been updated since 1995. This is because of the high cost of the Council's past forecasting methods, and because of a change in emphasis in dealing with forecasting uncertainty. Therefore, the company now uses three basic growth scenarios encompassing a reasonable range of outcomes with which to test the robustness of resulting supply-side resource choices discussed in Chapter D of this Plan.

Forecast gas requirements are presented and evaluated in a number of ways. For each growth scenario, 30 years of future daily gas requirements are developed. Daily gas requirements are developed for two basic weather scenarios for planning purposes: (1) a severe cold weather year, including a very cold design peak day, and (2) normal or average weather conditions. Expected gas requirements using cold weather assumptions drive decisions to acquire new supply-side resources. Gas loads under normal weather conditions allow the cost of new resources to be evaluated on a per unit of normal sales volume basis.

The approach to Demand Side Management (DSM) or Energy Efficiency (EE) in past plans differs significantly from the approach taken in this Plan. Following the Oregon UG 143 docket the company has a partial decoupling mechanism in Oregon as well as a new approach to the acquisition of EE. The company has adopted a Public Purpose funding mechanism that provides the Energy Trust of Oregon (ETO) with predictable annual levels of funds for the acquisition of cost-effective conservation through programs of its own design. To enable this approach, the company was allowed to institute a decoupling mechanism that makes the company indifferent to changes in revenues resulting from the success of the ETO in reducing gas use by residential and commercial customers. This is discussed further in Chapter C of this Plan.

Now, rather than using a mathematical programming model to make supply-side and demand-side resource choices simultaneously, we simply reduce the demand forecast by recognizing the conservation load shape and energy savings goals as forecast by the ETO. The demand forecast is not adjusted for the installation of specific energy efficiency devices in Washington, but is adjusted for trends in energy efficiency.

For the 2004 IRP, the company continues to use district-specific forecasts, reflecting the company's segmentation of its system into eight geographic districts. However in this Plan, district level forecasts acquire greater importance. The mathematical programming model now focuses on district level demand and supply nodes and the distribution system connections between nodes. In prior plans, supply-side resource acquisition took place on a system level basis without attention to distribution system detail.

Because districts differ in terms of weather, customer gains, and usage patterns by customers, the company's use of eight district forecasts results in useful information to guide infrastructure planning. Due to proprietary concerns, the results of the individual district level forecasts are not presented in detail. Aggregated (state or system) results are presented and are used to summarize forecast results. However, details are shown for the Portland district in order to highlight methodological aspects of modeling use per customer.

II. KEY FINDINGS

- Of the three primary growth scenarios -- low, medium (Base Case), and high) -- the medium forecast is most representative of previous trends in customer acquisitions experienced by the company, and it is the base case scenario chosen for this planning cycle.

- Peak day gas requirements are projected to increase significantly over a 30-year planning horizon, rising from 8.8 million therms to over 14.5 million therms. As reflected in Table A-1, growth in firm annual gas requirements under the Medium or Base Case scenario is 1.7 percent in the first five-year period, 1.7 percent per year in the first 10-year period, 1.8 percent in the first 20-year period, and 1.7 percent overall for the entire 30-year planning horizon.

- Forecast peak day requirements have fallen significantly from the levels contained in the 2000 IRP due to diminished levels of use per customer due to increased gas prices as shown in Figure A-1. When the Base Case forecast is compared to the case identified as "IRP 2000 Coefs", we see a decline of approximately 14 percent in the initial year of the forecast.

Table A-1

Firm Gas Requirements Growth Rates*
(Annual Requirements under Normal Weather)

	First Five Years	First 10 Years	First 20 Years	First 30 Years
High	2.2%	2.4%	2.3%	2.1%
Medium	1.7 %	1.7%	1.8%	1.7%
Low	1.5%	1.3%	1.2%	1.1%

* Average annual growth rate through end of the period indicated.

Figure A-1 and Figure A-2 depict the requirements (load) forecasts on a peak day and annual normal weather basis after adjustment for the impact of ETO conservation programs and trends in use per customer levels. A summary of forecast components by market segment for the base case appears in Chapter F at pages FF-27 through FF-30.

Figure A-1 also depicts two sensitivity cases (also discussed in Chapter D, Section VI, Part B) one uses the 2000 IRP's design weather assumptions and the other uses use-per-customer equations from the 2000 Plan. With respect to the first sensitivity, both Plans used approximately the same peak day event in design weather computations so that most of the difference occurs off-peak as discussed in Section VII of this Chapter.

The effect of the second sensitivity case is more dramatic. The 2004 Plan's base case peak day requirement is much lower than the 2000 Plan. This is due primarily to the North American gas industry's entry into a new gas supply situation involving much higher wholesale and retail prices with forecast peak day demands approximately 14 percent below expectations in the 2000 Plan.

The January 5, 2004 "Cold Snap" firm sendout of 7.3 million terms is shown as the last plot point in the "actual" series and represents a weather event that was approximately 19 percent warmer than our design peak day planning standard.

Figure A-1

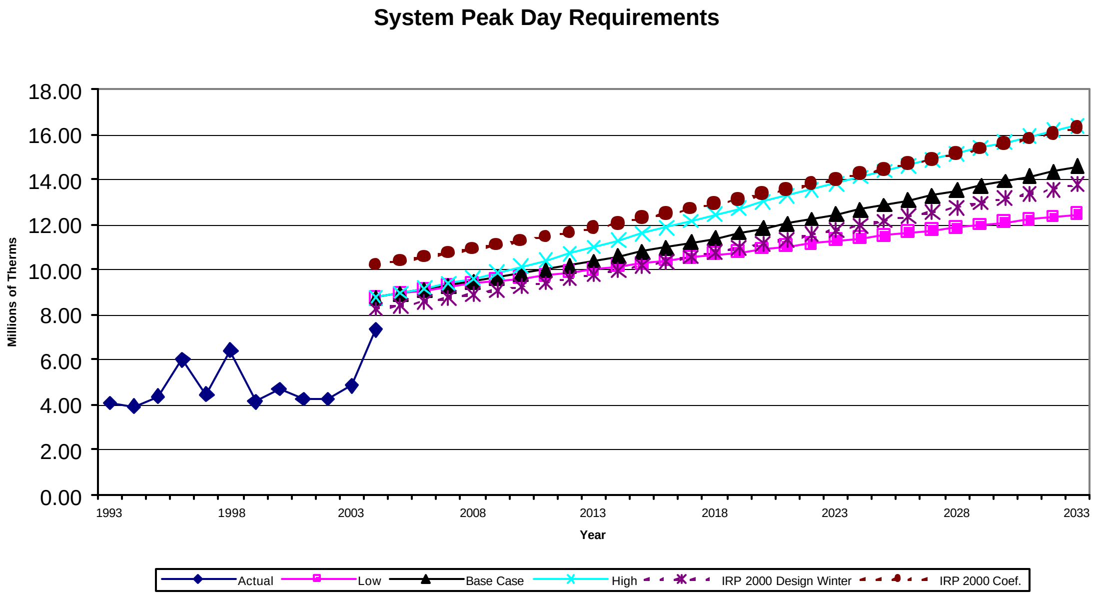
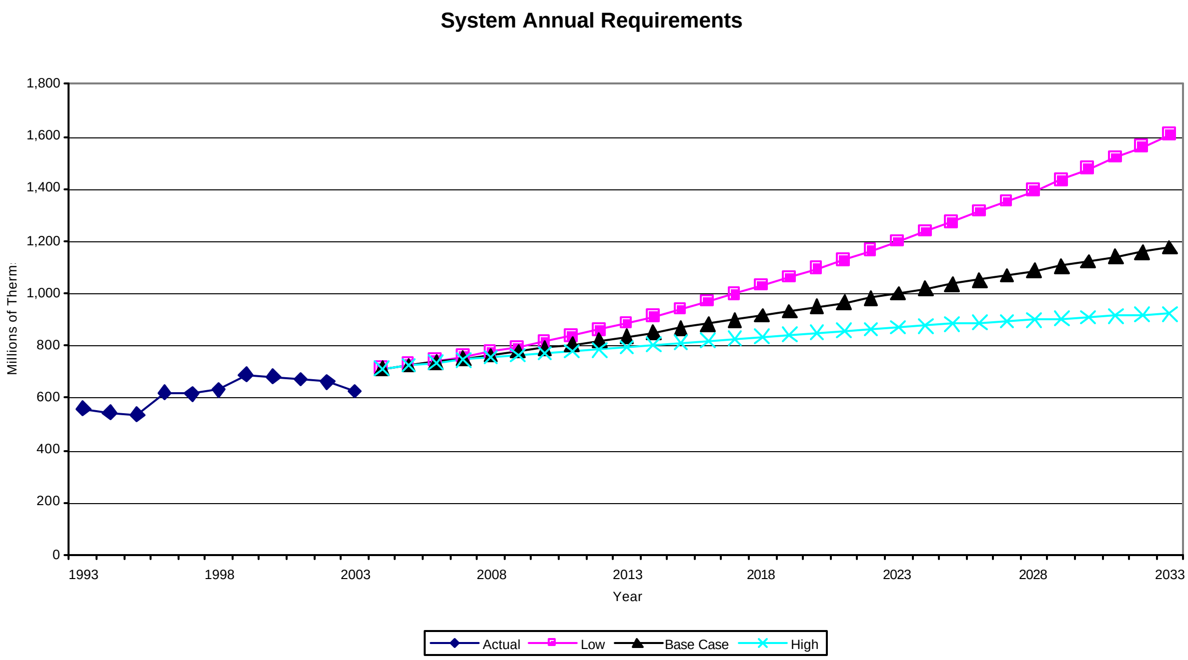


Figure A-2



III. OVERVIEW OF FORECASTING METHODOLOGY

The process for developing gas requirement forecasts follows several stages as outlined below. The company first projects customer counts by customer sub-class for each year of the forecast time horizon, and for the Base Case, as follows:

Residential:

- Existing customer base reduced for attrition over the forecast period

- New Construction customers gains (single family and multi family):
  - Through the 2004 to 2011 period
    - Oregon Economic and Revenue Forecast (OERF) of housing starts
  - For 2012 to end of forecast in 2033
    - Trend extended from 2012 based on trend displayed during the last 5 incremental changes in annual increment customer gains.
  - Share of housing starts in service territory are allocated in proportion to Woods & Poole forecast of population by county
  - NW Natural share of housing starts in service territory
  - Reduced for attrition over the forecast period

- Conversion customer gains:
  - Through the 2004 to 2011 period
    - Stock of convertible dwellings in service area districts served by Oil and Other Fuels
    - Additions to stock due to off main growth.
    - Oregon Economic and Revenue Forecast (OERF) of CPI and Personal Income
    - Ratio of Electric to Gas Rates
  - For 2012 to end of forecast in 2033
    - Trend extended from 2012 based on trend displayed during the last 5 incremental changes in annual increment customer gains.

Commercial:

- Existing customers reduced for attrition over the forecast period

- New Construction customer gains:
  - Through the 2004 to 2011 period
    - Driven by prior year OERF manufacturing employment and the ratio of gas to electric rates
  - For 2012 to end of forecast in 2033

        - Trend extended from 2012 based on trend displayed during the last 5 incremental changes in annual increment customer gains.
    - Distributed to districts in proportion to Woods and Poole population forecast through 2025, with W&P 2025 levels held constant through 2033
    - Reduce for attrition over the forecast period

- Conversion customer gains:
    - Through the 2004 to 2011 period
        - Driven by prior year OERF manufacturing employment and the ratio of gas to electric rates
    - For 2012 to end of forecast in 2033
        - Trend extended from 2012 based on trend displayed during the last 5 incremental changes in annual increment customer gains.

Industrial Firm:

- Customer gains derived from:
    - Current Industrial Customers by State (OR/WA)
    - Increased by expected Manufacturing Employment Growth
        - Woods and Poole forecast Manufacturing Employment Growth for Oregon.
        - Manufacturing employment growth for Washington based upon Woods and Poole manufacturing growth for Portland/Vancouver metropolitan area forecast of manufacturing growth rates

The company then statistically estimates gas usage equations for each customer subclass (or market segment).

Next, the company applies average and design weather conditions to customers and gas usage equations to derive firm gas requirements for each forecast scenario.

Forecasts are reduced for the effects of the ETO's conservation activities on energy efficiency.

Finally, the company applies growth and decay rates to base use and temperature-sensitive use per customer to capture the effects of non-ETO sources of energy efficiency improvement and added appliances.

IV. FORECASTING CUSTOMER GROWTH POTENTIAL

A. NEW CONSTRUCTION – RESIDENTIAL

Forecasting growth potential for residential new construction in the base case involves several steps. First the residential market is broken into two customer segments representing single-family and multifamily dwellings. Then the IRP forecast time horizon is broken into 2 parts. The first forecast time segment consists of the years 2004 through 2011 (actually the 2004-05 through 2011-12 heating seasons). Base Case results for this time period are driven by the Oregon Economic and Revenue Forecast of housing starts. The second forecast period is from 2012 until the end of the Plan's forecast time horizon in 2033.

For single-family dwellings a regression model relates actual new construction customer gains to historical Oregon housing starts. For the first forecast time period of 2004 to 2011, the regression model utilizes the OERF forecast of housing starts to forecast future single-family customer gains.

As with the single-family dwellings, a regression model fit to historical data provides a statistical relationship between penetration rates for the multifamily market and starts. Again for the forecast period of 2004 to 2011, the regression model utilizes the OERF forecast of housing starts to forecast multifamily customer gains.

Next, the forecast needs to be extended through the year 2033. In extending the forecast, the average number of customer gains for the years 2006 through 2011 by customer segment (single family and multi-family) is developed. This average of the last 5 incremental additions to stock are applied starting in the year 2012 until the final year of 2033. Essentially the average number of customers gained continues until the end of the IRP forecast horizon.

After system and state level customer gains are forecast, operating district population growth is used to allocate customer gains by market segment to individual operating districts. Population growth statistics available from Woods and Poole on the county level are used through the year 2025. State level customer additions are allocated to each operating district based upon the counties each district covers in the states of Oregon and Washington. To extend allocations past the year 2025 (the last year of the Woods and Poole forecast), the percentage allocation in the year 2025 is continued through 2033.

Figure A-3 shows residential new construction hookups since 1990, and into the year 2033. Figure A-4 shows the cumulative customer growth from residential single-family new construction over the course of the planning cycle, and Figure A-5 shows the cumulative customer growth from residential multi-family new construction.

Figure A-3

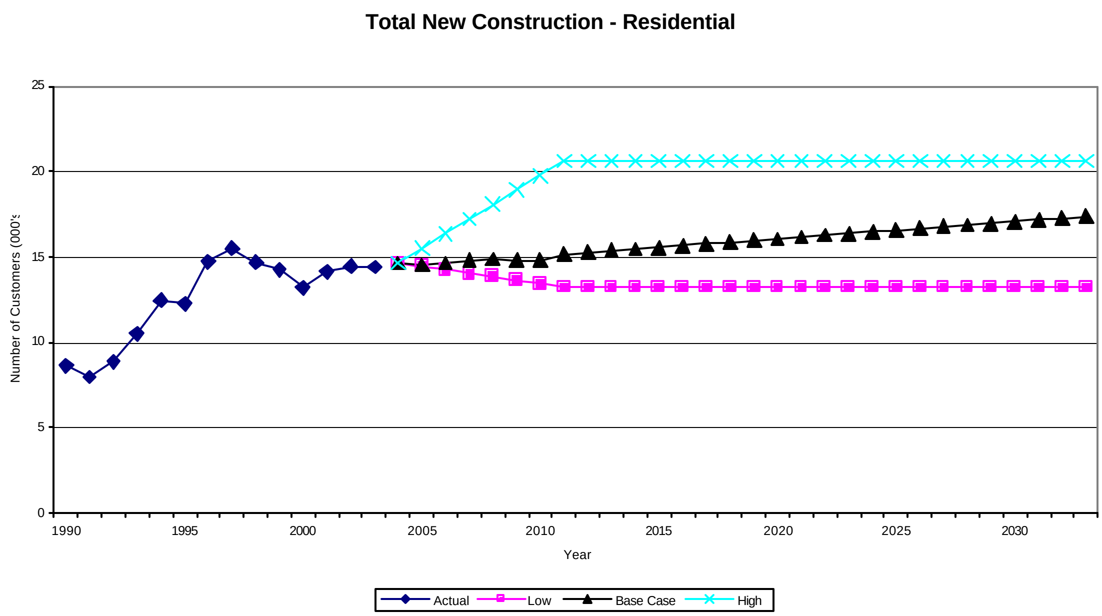


Figure A-4

Residential Single Family New Construction Adds - Cummulative

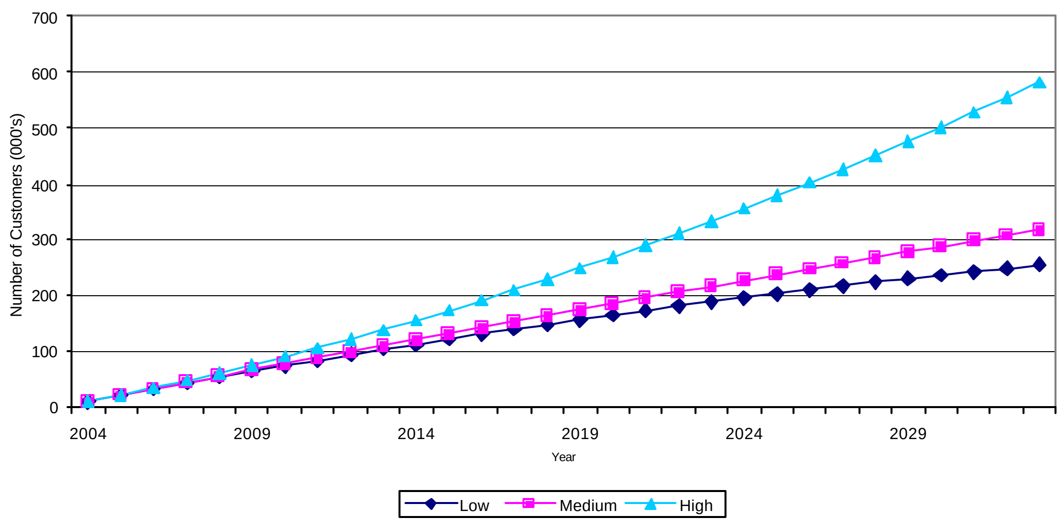
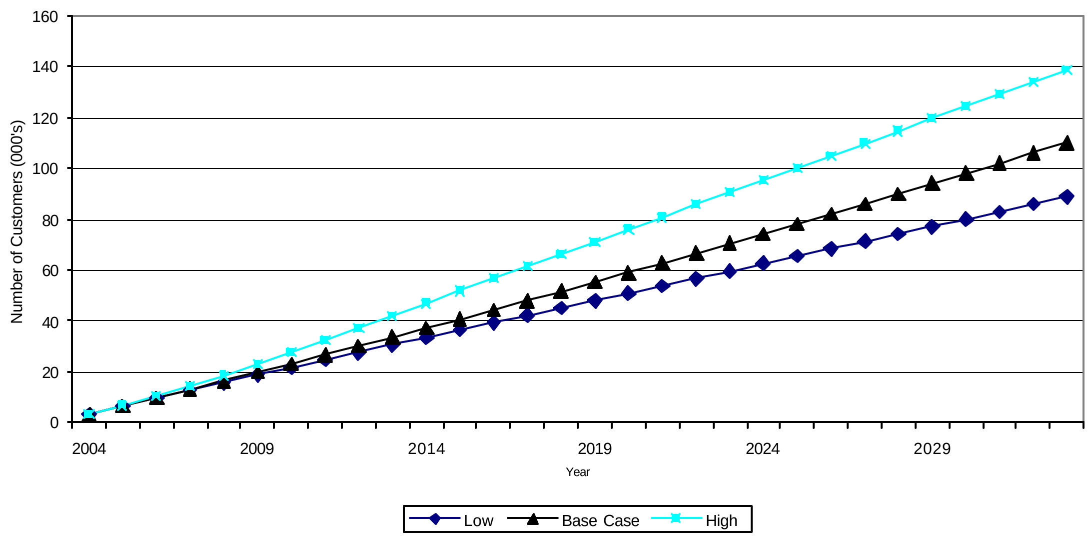


Figure A-5

Residential Multi Family New Construction Adds - Cummulative



B. NEW CONSTRUCTION – COMMERCIAL AND INDUSTRIAL FIRM

For the first eight years of the forecast, the company derives commercial new construction customer additions from regressions models driven by the OERF forecast of manufacturing employment and Gas to Electric commodity price expectations.

For the remainder of the forecast term, the company estimates new commercial construction gains by reviewing customer growth experienced in previous years. New construction customer additions are then allocated to operating districts by the Woods & Poole forecast of operating district population growth.

To estimate added customers for the first six years of the forecast, the company spreads county employment and changes in employment from the Woods & Poole forecast to districts in proportion to commercial customer counts, which in turn provides district specific growth rates.

Figure A-6 shows the annual growth levels experienced since 1990 and for each of the scenarios.

Figure A-6

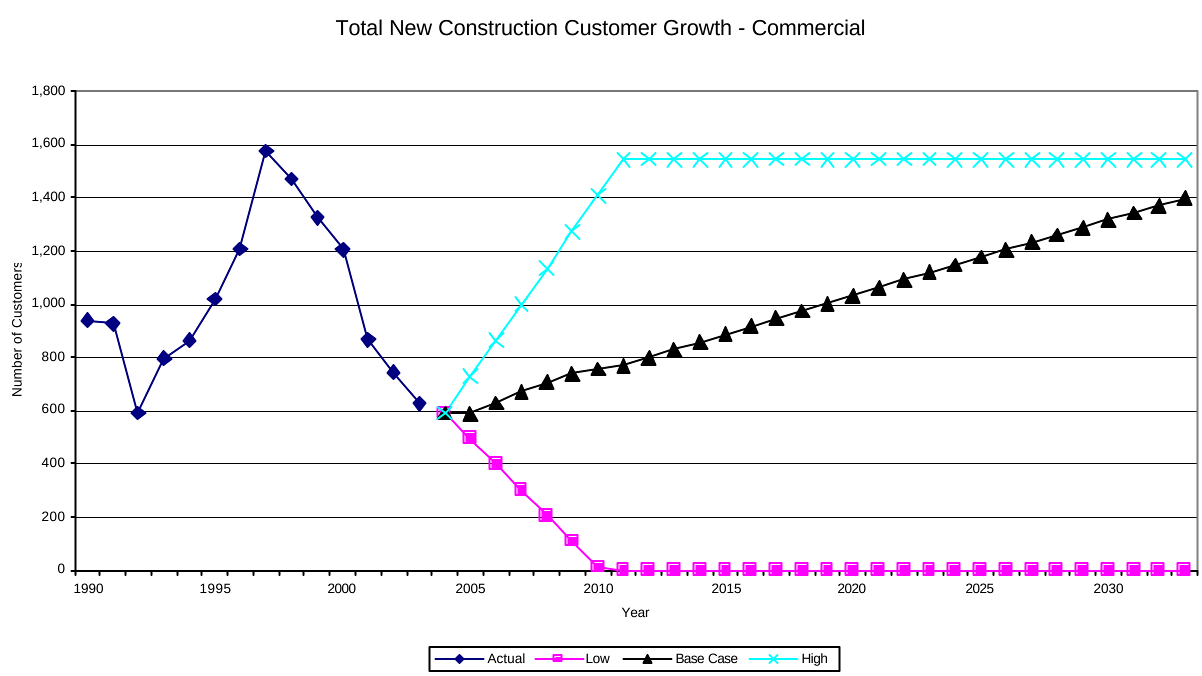
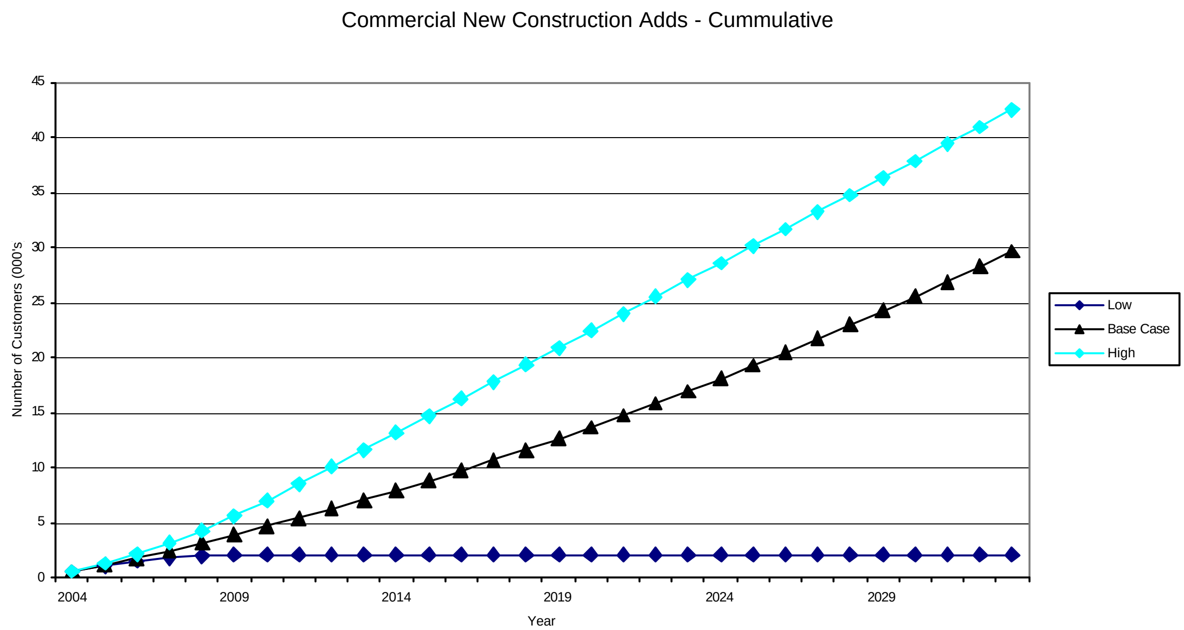


Figure A-7 shows the system's cumulative new construction commercial forecasts for the scenarios. Commercial customers increase by over 15,000 by the end of the planning cycle under the Medium scenario.

Figure A-7



C. CONVERSIONS FROM OTHER FUELS - RESIDENTIAL AND COMMERCIAL

The company estimates customer conversions to gas from other fuels by:

<u>Residential:</u>

- Evaluating conversion activity experienced by the company in prior years;
- Estimating the total stock of existing residential and commercial customers in the company's service area, and;
- Deducting the number of residential and commercial dwellings currently served by the company to derive the number of potential residential dwelling conversions available.

Commercial:

- Estimated by regression model of OERF Manufacturing forecast and the ratio of Gas to Electric prices forecast through 2011. The conversion trend is then extrapolated through the end of the forecast period.

Residential customer gains through fuel conversions are modeled using a starting inventory for the year 1990 of 72,900 Oil and 250,000 other stock, actual conversions and per capita income (1983). The forecast for residential customer gains through conversions uses the economic driver variables and stock conversion model through the first eight years of the forecast cycle. This trend is extrapolated through the end of the forecast period.

While the remaining stock of servable dwellings declines due to fuel conversions, it also grows as newly constructed dwellings are built using non-gas space heating fuels. Figure A-8 show the number of conversion customer additions being highest in the first years of the planning cycle, with more than 6,000 residential customer additions in the Medium scenario. It tapers off in the later years of the planning cycle to approximately 4,500 residential additions.

Future commercial customer gains through conversions are modeled based upon the historical relationship to manufacturing employment levels and the ratio of gas to electric rates. Figure A-9 shows the number of conversion customer additions through the planning cycle.

High and Low Growth Cases. Figures A-3 and A-6 reveal the Plan's results for residential and commercial annual customer gains for the High and Low growth cases. In Figure A-3, results for residential new construction customer gains depart from the Base Case forecast with the low case showing customer additions falling from the current level of 14,000 per year to a level of approximately 13,000 per year. The high case shows residential new-construction customer gains moving up to a level of 21,000 customers by the year 2011.

New construction customer gains for the commercial new construction market depart more radically from the Base case forecast in the High and Low cases. The High and Low growth scenarios for commercial new construction range from the highest number of customer additions ever achieved per year in the high case to a zero level of customer gains in the low case. The methodology for new construction customer gains in the High and Low cases involved forecasting customer additions using 25th and 75th percentile-level values for the driver variables observed during the past 14 years. In the High case, Oregon Economic and Revenue Forecast driver variables set at the 75 percentile level were allowed to play out until the 2011-12 heating season and were then capped at that level – a level that turns out to be near the highest level of new construction gains ever achieved historically. In the Low case, 25th percentile levels for economic drivers were allowed to run until the 2001-12 heating season and then capped at that level. The capped level in the Low case turned out to be zero customer gains for the remainder of the forecast period. The same treatment of economic drivers applies to both residential and commercial new construction gains.

Both the high and low cases are appropriate for sensitivity analysis purposes. However, the low case appears somewhat awkward when it is realized that we have used the same identical forecast of commercial-*conversion*-customer gains in both the High and Low cases. We do not have high and low versions of commercial conversion customer gains – Just the Base Case Level. An observer might note that if new-construction commercial customer gains go to zero, why are conversion gains unfazed by the implicit significant economic events impacting the new construction market. However, this outcome passes muster when viewed as part of a sensitivity analysis exercise.

At the present time, the *residential* conversion-market stock-adjustment model does not capture the effect of changing levels of additions to the stock of convertible dwellings that are implicit in the High and Low cases for new-construction customer additions. The *commercial* conversion model is regression based and does not allow for the recognition of changes in the stock of convertible structures resulting from different levels of system expansions. Nevertheless, the High and Low cases in the current Plan provide useful guidance for the evaluation of the robustness of the Plan's findings on supply-side choices. The resulting "Jaws" of the High, Base Case, and Low peak-day forecast displayed in Figure A-2 are wide enough to reflect a reasonable range of outcomes.

Figure A-8

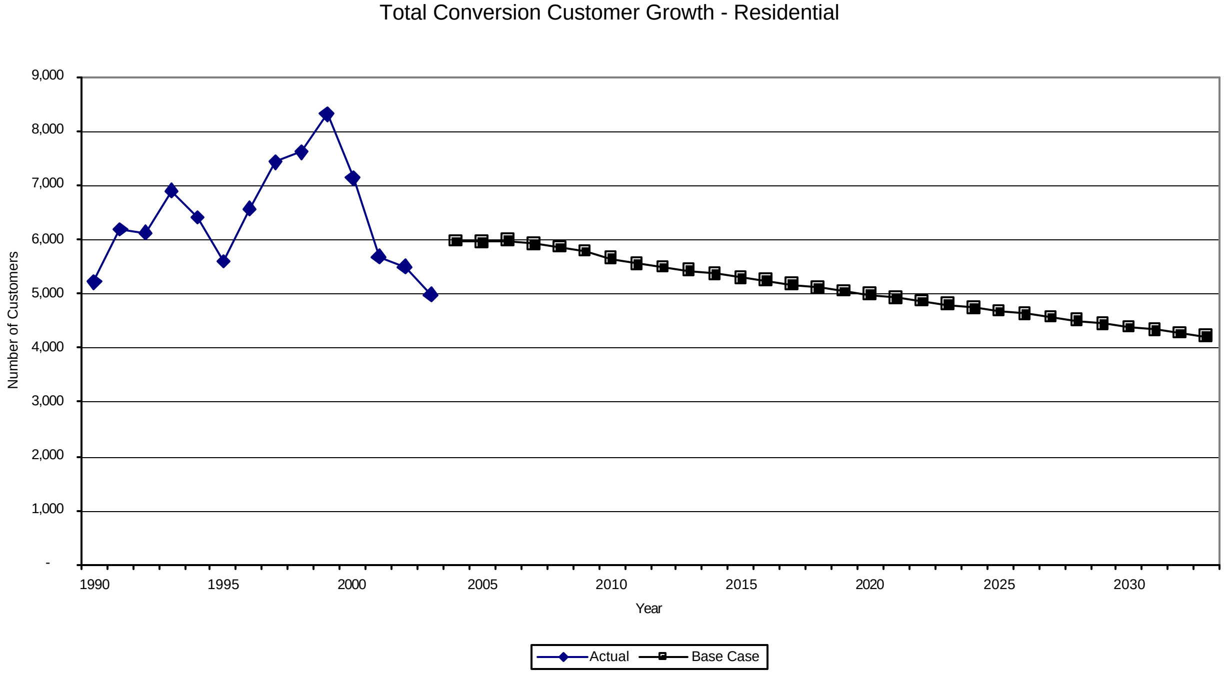
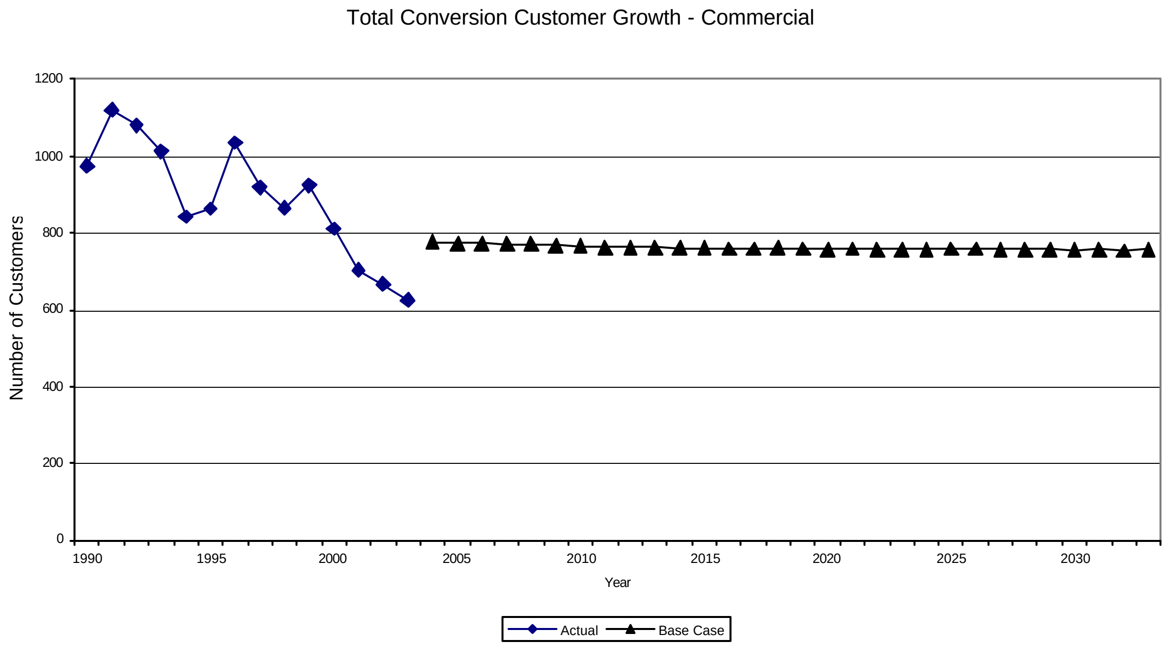

Total Conversion Customer Growth - Residential
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Number of Customers
1990
1995
2000
2005
2010
2015
2020
2025
2030
Year
Actual
Base Case

Figure A-9



Because the company believes there will not be a significant number of conversions to gas from other fuels within the industrial firm class of customers, zero conversions are assumed in the forecast for the industrial firm class.

Figures A-10 through A-12 graphically show the total number of customers since 1980, and the forecast additions from new construction and conversions through the year 2033. The Base Case scenario is most representative of historical trends in customer growth.

Figure A-10

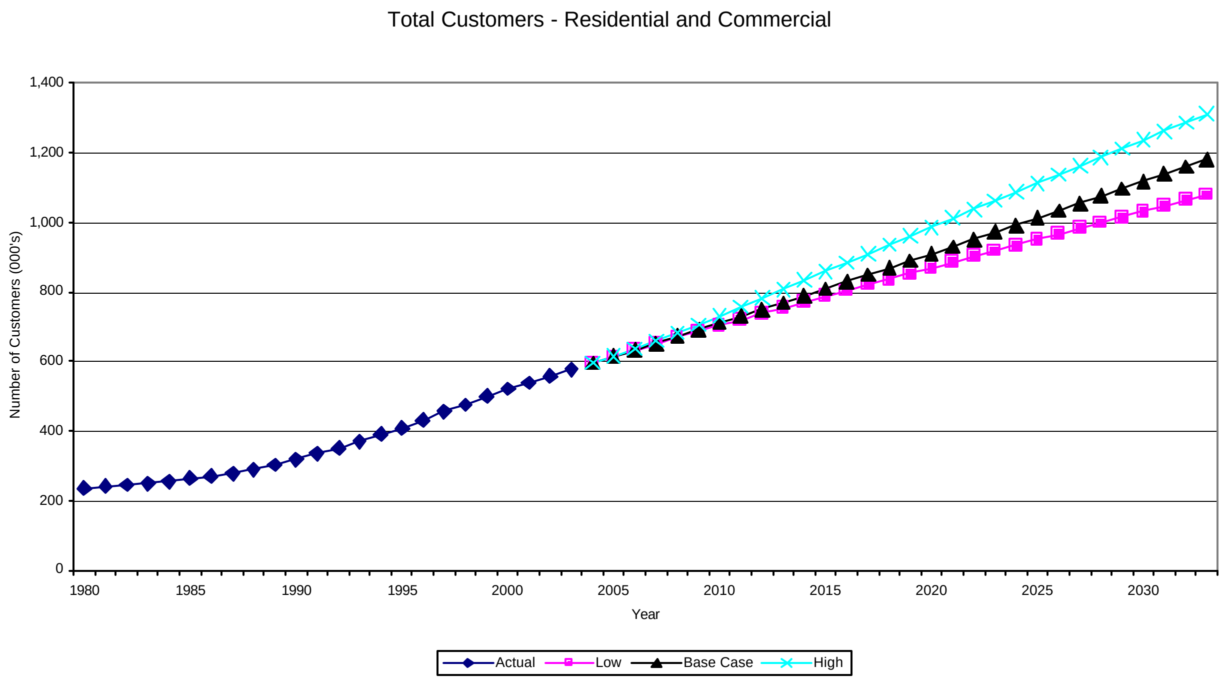


Figure A-11

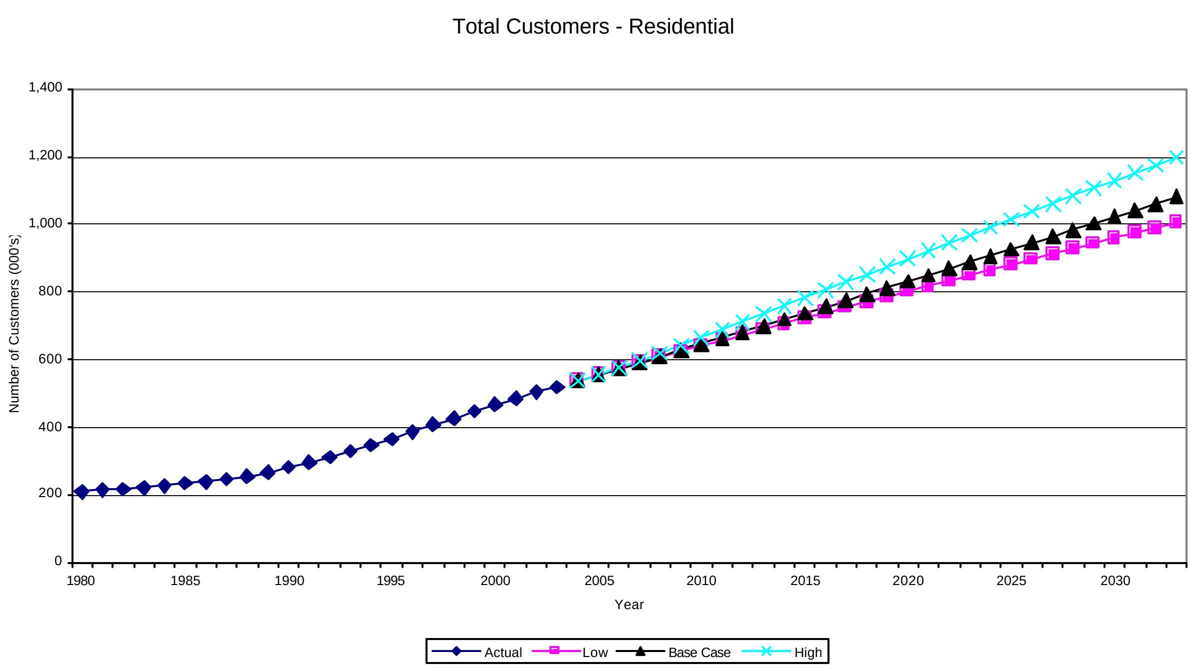
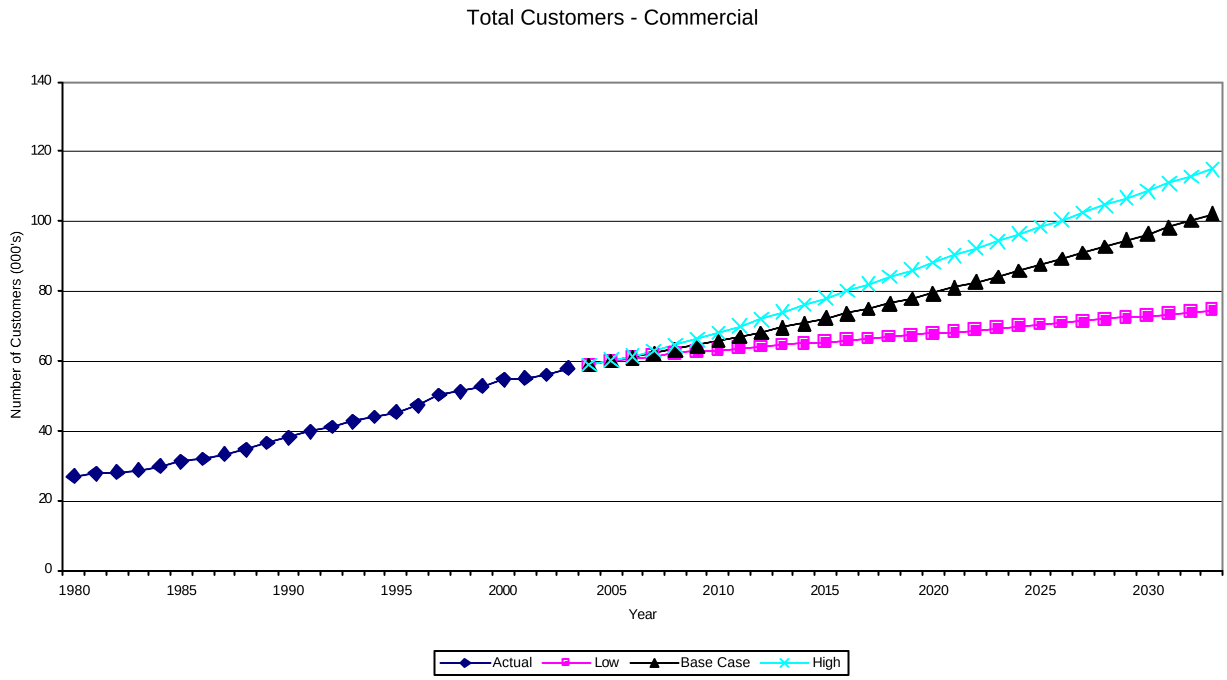


Figure A-12



V. FORECASTING GAS REQUIREMENTS (Use per Customer)

When estimating residential and commercial gas requirements, it is necessary to identify fuel use as a function of temperature by separating temperature-sensitive use from non-temperature-related use. This enables the company to better identify resources needed to serve peak loads under cold weather conditions by recognizing factors differentially affecting gas enduses. Non-temperature-sensitive use represents gas requirements for water heating, cooking, and other miscellaneous uses that are largely unresponsive to temperature variations. Non-temperature-sensitive use is expressed as the number of therms used per customer per day for these purposes and is often referred to as base use. The level of base use for residential and commercial customers has been relatively constant over a long period of time.

The concept of Heating Degree Days (HDD or Degree Days) is used to measure temperature. HDDs are a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature, usually 65 degrees Fahrenheit. For example, on a day when the mean outdoor temperature is 35 degrees F, there would be 30 degree days experienced. Following National Weather Service conventions, daily mean temperature represents the sum of the high and low readings divided by two, with days defined as the 24 hour period between midnight for each day. Consistent with past Plans, we use a 65 degree balance point assumption in this Plan.

Because of differences in the time intervals over which customer usage data and temperature data are captured, developing a method to match usage data to temperature data is vitally important. Monthly usage data for customers is available on a billing cycle basis, where meters are read for groups of customers over the course of a month rather than at month-end. As a result, usage data for any customer group is uniquely related to the number of days and degree days within the billing period being examined. To reveal the relationships between base use and number of days and temperature-sensitive use and degree days, for the entire class of use for a given month, the days and degree days must be transformed to reflect the same aggregation of various periods as the monthly billing cycle usage data. The transformation that is made is to weight the calendar days and degree days within the cycle period by the proportion of customers for each cycle to the total customers in that month. The weighted days and degree days are then summed for each month, providing a basis for determining the necessary relationships.[1]

Temperature-sensitive use is expressed as the number of therms used per customer per HDD. This compound ratio is commonly referred to as "Unit Consumption". For example, a residential customer might use 0.524 therms per day for base use purposes and an average of 0.143 therms per HDD for space heating purposes. The major sources of differences between various customers' space heating use per degree day are dwelling size, appliance efficiency, and the thermal integrity of the structure (how well it is insulated). Over time, conservation investments change usage for existing and conversion dwellings.

The amount of non-temperature and temperature-sensitive gas requirements used in the company's forecast differs between new construction additions and conversion customer additions. These differences are largely a result of newly constructed buildings and dwellings using natural gas for both space heating and water heating, but buildings and dwellings that convert to gas heat have a lower percentage of gas water heaters. Because of this, water heater additions are explicitly modeled for the existing stock of residential customers and the growing stock of residential conversion customers (see page AA-12).

A. RESIDENTIAL AND COMMERCIAL LOAD EQUATIONS

Equations for forecasting daily gas requirements for each customer class all use the same general functional form. These equations are derived from regression analyses of historic data, and numerically represent the relationships between customer counts, weather changes, and energy use. Non-temperature-sensitive use, or that level of daily use that does not vary with a change in degree days, is separated from temperature-sensitive use, or the amount of use that does vary with a change in daily degree days (see Pages AA-1 and AA-2). Base use is determined using July through September data and heat use is defined as total use less base use, and the usage coefficients are derived from regression equations relating heat use per customer per degree day to degree days per day. Non-temperature sensitive use per day is the same for any day of the year while temperature-sensitive use is highest on a peak day and drops to approximately zero on a day when no degree days are experienced. Computationally, trends in non-temperature-sensitive use and temperature-sensitive use over time are included as a Growth-Decay Factor. A summary of the general functional form follows.

Daily Requirement = Customers * [(Non-temperature-sensitive Use * Growth-Decay Factor) + (Temperature-Sensitive Use * Growth-Decay Factor)], and

Temperature-Sensitive Use = [HDD/D * EXP[Constant +Weather Elasticity * LN (HDD/D)]], where:

- HDD/D equals the HDD for a specified day;
- equations are calibrated using district-specific weather;
- when HDD equals or exceeds 45, the Use Factor indicated for 45 HDDs is used;[2]
- equations are used for 2004-05 and later heating seasons;
- LN(A) = Natural Log of A;
- Exp(A) = e to the power A, and;
- “*” indicates multiplication.

Development of the temperature-sensitive use factor equation for existing residential customers is detailed on pages AA-1 and AA-2 and uses the Portland District as an illustration. Portland results are summarized on page AA-3. The tables on AA-4 through AA-7 summarize NW Natural's customer class and total firm requirements forecasts under each of the company's three primary load growth scenarios. The figures on pages AA-8 through AA-11 show the temperature sensitivity and load shape comparisons for the residential and commercial sectors under normal weather and under colder weather conditions. Table A-2 shows the existing, conversion, and new construction subclasses within the residential and commercial sectors and the usage equation coefficients for each, as well as the industrial firm coefficients.

Table A-2

Residential, Commercial, and Industrial Firm
Portland Use Factor Equation Coefficients

	Base Use		Temperature-Sensitive Use	
	Constant	Weather Coefficient	Constant	Weather Elasticity
Residential				
Existing	0.53155	.07119	(3.10787)	0.36733
Conversions	0.37578	0.941	(3.34275)	0.40476
Single-Family New Const.	0.76039	0.997	(3.68100)	0.56594
Multi-Family New Const.	0.39111	1.014	(4.49487)	0.56825
Commercial				
Existing	5.15889	0.30522	(1.6884)	0.40597
Conversions	2.34195	0.937	(0.45335)	(0.007706)
New Construction	8.46948	0.966	(0.82535)	0.19282
Industrial Firm				
Existing	N/A	N/A	5.52937	(0.875493)

Page AA-12 shows the base use and heating use Growth/Decay factors that have been included in the Base-Case forecast to reflect added appliances, improved appliance efficiency and the effects of ongoing conservation activity outside of programs run by the Energy Trust of Oregon. The Base-Case assumes that water heater additions tend to be offset by improvements in water heater efficiency ratings in the residential sector. Base use in the commercial sector declines due to water heater efficiency improvements without the offsetting effect of water heater additions.

Temperature sensitive use declines more dramatically due to the combined influence of more efficient appliances and changes in the *effective* square footage of homes. While actual square footage is likely to increase over time, the base case assumes that effective square footage will decline as home heating strategies change in response to higher gas costs by adapting to zonal approaches to space heating. We expect to see occupants closing off parts of dwellings and commercial structures by closing vents and doors, and using "smart home" technologies that more carefully control when and where space conditioning takes place. By the end of the forecast period, space-heating usage per customer falls from 80 to 93 percent below current levels in the various market sub-segments.

Adjustments for Energy Trust of Oregon Conservation Activity. The demand forecast for Oregon and the company's operating districts in Oregon are adjusted downward to reflect the effects of the Energy Trust's energy efficiency activity. Public purpose funding for the ETO and funding for other purposes are summarized in Chapter C, and page CC-1 in particular. Oregon ratepayers provide approximately $6.8 million in annual funding for ETO programs.

Page AA-13 summarizes the Trust's planning estimates of energy savings through the year 2012. By 2012 the ETO projects an amount of energy savings equal to approximately 1.4 years of growth in annual energy requirements for the system (18.8 million therms in annual savings divided by 13.0 million therms in annual energy requirement growth). Water heating savings amount to approximately 15 percent of the ETO's total estimated savings. Residential class savings amount to approximately two thirds of the total savings and commercial class savings constitute the remaining third.

The mechanism that applies the ETO's energy and capacity savings to the Plan's district level forecasts reflects the following approach (note that the ETO's year 2004 is treated as the 2004-2005 heating season, or 12 month period ending in June):

1. Allocate ETO energy and capacity savings to districts in proportion to the number of residential and commercial customers in each year (excluding the Washington service area).

2. Allocate ETO's space heat savings within districts in proportion to the total design weather heating degree days in each district and within each temperature bin. (There are 15 temperature bins for each analytic year as explained in Chapter D).

3. Allocate ETO's water heat savings in proportion to the number of days in each district temperature bin.

Low Income Weatherization Programs and Other Programs. Chapter A's forecast gas requirements do not explicitly include the effects of the two low-income weatherization programs running in Oregon and Washington, and the effects of two other small-scale programs also running in Washington. Public purpose funding in Oregon provides as much as $1.3 Million per year for low-income weatherization efforts and a recently approved tariff in Washington provides for approximately $0.1 million per year. These programs and their prospects are discussed more fully in Chapter C.

The effect of these three programs is small compared to the main thrust of ETO activity, and is small in relationship to the statistical noise inherent in a forecasting effort of this nature. The company supports these programs and continues to work on improving their performance. Not providing explicit recognition of their effects over the forecast planning horizon does not diminish their importance to the company and its customers. In any case, the use per customer growth and decay factors presented at page AA-12, as an approximation, captures the effects of these 3 programs.

B. INDUSTRIAL FIRM LOAD EQUATIONS

Industrial firm requirements use a slightly different functional form insofar as base use is not isolated. The following equation applies to Oregon Firm Industrial sales customers:

Daily Industrial Firm Therms =
Customers x HDD/d x Exp[5.52937+ (0.875493)*LN(HDD/D)]

The mix of transportation and sales gas serving industrial firm requirements has varied over time depending on the company's cost of core-market portfolio gas in relationship to opportunities perceived by customers in gas commodity markets. In past plans, the entirety of expected industrial firm throughput was treated as a core-market requirement for long-term capacity planning purposes under the assumption that transportation customers would seek to return to firm sales service during periods of gas supply system stress. In this plan, only the requirements of firm sales customers are included in the base case forecast.

C. INTERRUPTIBLE CUSTOMER REQUIREMENTS

The company carefully examines the best mix of supply-side resources to meet the needs of its firm sales customers. Interruptible load is served only with capacity in excess of that required for core market customers. When capacity is scarce, interruptible load is curtailed. The interruptible customers can claim no dedicated company resources other than the services that connect them; and given the slow change in industrial customer counts, even these few dedicated resources rarely change.

Interruptible gas users fall in the gas transportation category, and are held constant in each of the three forecast scenarios. Historical usage is shown in the appendix to this chapter in the chart at page AA-14. Industrial interruptible sales and transportation annual volumes are projected at about 500 million therms for 2004 as well as in future years of the planning period.

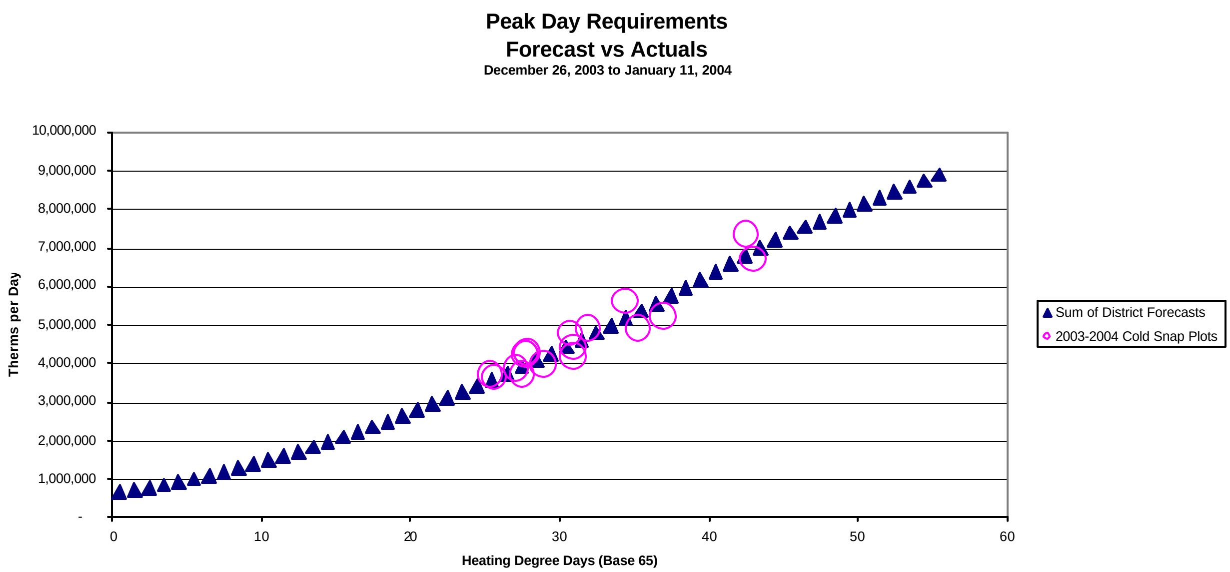
The use of an unchanging fixed volume forecast reflects the basic nature of the load in question. Large industrial and institutional users generate most of the interruptible load. Few of these entities are added or depart over time. The gas usage of these entities is fairly constant, although their choice of fuel may not be. These large customers usually have the ability to move freely between competing fuels. Some have the capability to bypass NW Natural's system and their choice of energy sources depends primarily on relative prices.

Positing fixed interruptible loads over the planning period makes sense, particularly in light of the fact that the company does not need to plan either capacity or energy purchases to serve these customers. No variation in industrial interruptible deliveries would cause a change in company gas supply planning operations. Company gas supply planning is undertaken to provide reliable energy to firm sales customers, not interruptible customers.

VI. FORECAST EQUATION PERFORMANCE

For capacity planning purposes, the company is primarily concerned about gas usage behavior during severe weather episodes. Unless the company has experienced a recent cold spell, it is difficult to measure forecast accuracy. Fortunately, during January of 2004 a significant "cold snap" took place in the company's service area. Figure 13 shows the relationship of actual core-market gas use to predicted gas use during the period December 26, 2003 through January 11, 2004. In examining the results it should be borne in mind that the underlying equations were calibrated during the July 2000 through June 2003 time period – a time period preceding the cold weather episode.

Figure A-13



The forecast values in Figure A-13 represent the sum of individual district forecasts for each day. Forecast errors at the individual district level tend to be larger in percentage terms. Nevertheless, overall performance at the system level is quite satisfying. For the seventeen observations, Root Mean Squared Error is approximately 400,000 therms, suggesting a 90 percent confidence interval of approximately 660,000 therms. Northwest Natural plans for the point forecast values recognizing that actual gas demand on any given day can significantly exceed for fall below the forecast values.

VII. FORECASTING FOR WEATHER VARIATIONS

As previously discussed, forecasts of gas requirements depend on the approach the company takes in establishing expected weather patterns for planning purposes. The approach taken utilizes strips of weather history to construct design winter conditions. Over the past 25 years, the 1978-79 heating season presented the most demanding period faced by NW Natural. The second most demanding was the 1985-86 heating season. Although the extreme cold weather experienced in February 1989 had a much colder peak day, it was otherwise a very mild heating season. Going back 50 years, the 1949-50 heating season was the most severe of all. These years are compared in Table A-3, using Portland data as the basis for the comparison:

Table A-3

Historical Heating Degree Days (HDDs)*

Heating Season	Peak HDD	Number of Days Colder Than: 49 HDD	38 HDD	29 HDD
1949-50[3]	58	7	19	32
1968-69	54	2	9	29
1978-79	49	0	8	60
1985-86	46	0	8	38
1988-89	53	2	2	9

* As reported at Portland International Airport.

For least cost planning purposes the company uses the most severe weather and resulting load forecast that could be expected in a 20-year time span. With this plan, the 1978-79 winter drops out of the 20-year time frame, and is replaced by the 1985-86 winter as the most severe within the most recent 20 years, and forms the basis for the derivation of the design weather year. Therefore, the forecasts reflect firm service demands associated with the most demanding days of the 1985-86 cold weather season augmented by the addition of the 52.5 HDD peak day experienced during the 1988-89 heating season. This 52.5 HDD value for Portland is calibrated such that the system weighted average equals 52.9, that represents the system weighted peak day HDD event experienced on February 3, 1989.

The basis for the derivation of each district's peak day is as follows:

Page AA-15 of the appendix to this chapter summarizes severe weather occurrences by district and on a system weighted average basis since December 1968. Days involving a system weighted average temperature greater than 47 HDDs are chosen from the historical record. Basing extreme weather planning on the single coldest day for each district during the period is examined and would produce a system average of 55.8 HDDs. However, this represents a non-coincident event, insofar as these temperatures were not achieved during the same cold weather episode, thus resulting in too high a standard for planning purposes.

The Portland metropolitan area represents approximately 62 percent of total customers in NW Natural's service territory, and therefore dominates calculated system weighted averages. But equivalently cold temperatures in other districts do not always accompany a cold day in Portland. For example, the record cold 54 HDD event observed for Portland on December 30, 1968, involved only 40 HDDs at the Eugene weather station. Similarly, the record cold 64 HDD event observed for Eugene was accompanied by 48 HDDs in Portland. A "restated" coincident peak day for each district has been created by averaging five peak day events and adjusting the district averages such that the system weighted average peak day corresponds to the February 3, 1989, system weighted average peak day. The use of additional experienced peak days farther from the coldest day results in similar restated coincident peak day values for various districts, consequently we have chosen to use the 5-day approach that was employed in previous plans.

Thus, the design weather year used for the analysis of requirements is the result of combining the maximum HDD values from the following weather events in a load duration curve format:

1) Peak day as defined above (52.5 for Portland)
2) 1985-86 daily observations
4) 20-year average weather

The peak day of 52.5 HDDs replaces the observed coldest day of 46 HDDs that occurred in Portland during the 1985-86 heating season. The colder of normal or average weather and 1985-86 weather provides the remaining daily HDDs used in the design weather year. A similar replacement applies to each operating district's design winter weather. Pages AA-16 through AA-18 display the resulting design weather concept as it applies to Portland.

END NOTES

1 Methodology to Develop Usage Coefficients: A traditional difficulty in considering the relationship between customer gas use and weather is the mismatch of the reporting of use versus the reporting of degree days. Usage is reported monthly on a billing cycle basis such that on every working day of each month, meters are read and the use is recorded as cycle volumes. The cycle volume reflects the use by customers in that cycle for the approximate 31 days between the current read and the prior meter read. For cycle 1 of each month, for example, use may be related primarily to the prior month while cycle 10 would relate to half of the current month and half of the prior month, and so on.

With relative uniformity of customer counts and customer characteristics across all cycles, a regression could be conducted using equal weights applied to the cycle usage data and the degree day information that corresponded to each cycle. While the reporting for existing customers might approach this level of uniformity, the reporting for new business categories does not. For new construction and conversion customer additions, the representation of the new customers favors certain cycles. The application of the same weight to a data point that represents perhaps none or few customers as is applied to a data point representing many customers is inappropriate.

The solution is some method of aggregation that synchronizes usage observations and weather. The two methods that have been used are to "calendarize" cycle based usage data and regress the results against calendar month degree days or to "cycle-ize" degree days and regress the results against the total cycle data for each month. Calendarizing requires the monthly cycle data to be spread to the calendar months that the billing cycle data spans. Base use is spread based on the number of days within the meter-read period and heat use is spread in proportion of total degree days falling in each month. The weakness of this approach is that it assumes the heat use is allocable in direct proportion to degree days when analysis shows that use per degree day increases as a function of degree days per day (particularly when using a balance point assumption of 65 degrees).

Due to the weakness in "calendarizing" usage, the “cycle-ized” degree day method is used here. The adjustment required with this approach is to produce a weighted average degree day series and days in cycle series that is based on the number of customers in a given cycle. For cycles that have no customers, the information is given zero weight. Degree days and days in the period data receive higher weight for cycles with more customers.

2 NW Natural's core market forecasting methods include an element of "bend over" for the residential and commercial classes. This is shown at pages AA-9 and AA-11. While residential and commercial bend over has not been observed empirically, it is necessary to recognize the phenomenon when extrapolating use factor equations calibrated using monthly observations that never exceed 35 heating degree days per day to more severe weather. The company has assumed that when HDDs exceed 45, an increasing number of gas heating appliances are running at full capacity and that gas use per heating degree day (unit consumptions) will not increase further as the weather gets colder.

NW Natural cannot empirically identify the bend over phenomenon because we have not experienced a recent cold spell of long duration in the range of HDDs where bend over would be expected to occur. In part, national interest in this concept arose because of the prolonged cold spell experienced on the East Coast during the 1993-94 heating season.

3 We do not plan for a repeat of the 1949-50 weather episode, that falls within a coldest-in-fifty-five-year time frame. It would be considerably more expensive to base our design weather year on the 1949-50 episode instead of the augmented 1985-86 episode we currently use. As a rough approximation, the 1949-50 winter would require another generic underground storage facility at Mist, Oregon, to be on-line at the present time. Moving from a peak day HDD value of 52.5 for Portland to 58 HDDs would require an additional 900 thousand therms of daily deliverability. Beyond this, because there were so many days exceeding 49 HDDs and 38 HDDs during the 1949-50 episode, more than just additional peak day capacity would be required. What is required is additional working gas -- either in the form of storage gas inventory or additional interstate pipeline capacity.

This issue has often been discussed within the company. The company is prepared to launch a variety of highly-publicized voluntary curtailment strategies rather than commit to the expense of obtaining the additional supply-side resources necessary to meet a repeat of the 1949-50 experience.

If historic winter conditions such as 1949-50 occur, or if resources do not perform as expected, then emergency actions may be necessary to prevent outages to firm customers. For example, *carte blanche* may be given to suppliers to round up additional supplies. In addition, emergency capacity exists at the storage plants that would permit withdrawals at higher-than-planned rates, albeit at the risk of temporary or permanent damage to the facilities. Public appeals may be broadcast to lower thermostat settings. As a last resort, gas transported to interruptible customers may be preempted if absolutely necessary to avert firm outages. Therefore, a certain amount of emergency capacity exists in the system to assist in meeting the extraordinary requirements of firm customers.

CHAPTER B: SUPPLY-SIDE RESOURCES

CHAPTER B: SUPPLY-SIDE RESOURCES

I. OVERVIEW

This chapter discusses the gas supply resources that the company will use to meet existing firm customer supply requirements, as well as the supply-side alternatives that could be used to meet the forecasted growth in gas requirements as described in Chapter A. Supply-side resources include not only the gas itself, but also the pipeline capacity required to transport the gas, the company's gas storage options, and the system enhancements necessary to distribute the gas. This chapter surveys existing and potential resources without judgment as to the resources that will be chosen. Chapter D describes the actual linear programming optimization process, which selects the resources that are least cost under a variety of load growth scenarios.

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the company's firm customers. The amount of gas needed is greatly influenced by customer behavior. Several factors can affect customer behavior, and can cause daily, seasonal, and annual variations in the amount of gas required. Much of this variation is due to changes in the weather. However, changes in business cycles, and the price of natural gas service in relation to other fuel alternatives, may also influence a customer's gas use. These behavioral factors are accounted for in the company's gas requirements forecast, and are discussed in more detail in Chapter A.

The ability to plan for customer requirement variations while maintaining reliability of service is best accomplished by keeping a variety of supply resources available. The company's current supply portfolio consists of both contracted natural gas supplies, which can be used year-round and transported on the interstate pipeline system, and storage gas supplies, which are stored either underground or as liquefied natural gas (LNG) in tanks. Both can be used as peaking resources during periods of extremely high demand.

Another resource in the company's portfolio is a variation on storage. It consists of recallable supply arrangements with industrial customers, gas-fired electric generation plants, and/or with the gas suppliers serving such facilities. The terms of these agreements allow the company to call on gas supplies controlled by these parties for a limited number of days during the heating season. For a variety of reasons this resource most closely resembles LNG service. The alternate fuel tanks of the end-users could be thought of as the storage medium. Since the end-users for these gas supplies either have to shut down or switch to alternative fuels, the duration for such service is limited, like LNG.

Its delivery to or within the company's service territory again mirrors that of the company's LNG plants and related contracts. Finally, like LNG, this is a relatively expensive resource on a pure ¢/therm basis. That is because prospective suppliers of this service expect it to be called upon during the harshest weather, when alternate fuel costs are highest and re-supply is uncertain, and so they must include the possible cost of plant shutdowns and product loss. Most customers are simply unwilling to even consider providing such a service on a negotiated basis, and others may be too small to be of interest to the company. However, the company continues to pursue such resources where feasible.

Absent price elasticity effects, NW Natural's gas supply requirements generally increase as its firm customer population grows. The characteristics of this load increase are a critical component of the resource selection process. For example, water heater demand is relatively constant throughout the year. Additional water heater load could be met most efficiently and economically by a resource that has the same deliverability year-round -- a "baseload" resource. The growth in space heating requirements tends to be highly seasonal in nature. This type of load growth is best met with a combination of "baseload" and "peaking" resources. Peaking resources are designed to deliver large volumes of gas for a short duration, such as during cold weather.

The effects of price elasticity add another layer of complexity onto gas requirements. When prices go up, consumption should decrease to some extent. This may be due to structural changes and choices, such as the installation of higher efficiency appliances and insulating materials. Or, it may be due to behavioral changes, such as turning down thermostat settings or dressing warmer. The structural changes should persist under most conditions, but the behavioral changes could be easily reversed. For example, lowering the thermostat may be a customer’s response to high prices, but during an extreme cold weather episode, the customer may decide to raise the thermostat rather than risk frozen pipes or other discomforts. This may be a temporary move that has a negligible impact on annual requirements, but it could directly correlate to, and have a non-trivial impact on, peak day requirements.

Given these complexities, the company has assembled a portfolio of supplies to meet the projected needs of its firm customers. At the same time, this portfolio is flexible enough to enable the company to negotiate better opportunities as they arise. Existing contracts have staggered terms, ranging from 10-year terms to very short-term arrangements of 30 days or less. This variety gives the company the security of longer-term agreements, but still allows the company to seek more economic transactions in the shorter term.

II. KEY FINDINGS

- For this planning cycle, the company's gas supply procurement strategy will rely on the transportation of supplies priced at negotiated rates that will follow market prices on an annual, seasonal or monthly basis.

- A portfolio of fixed price supplies ranging 3-years from the current period is desirable because it dampens volatility and assures more stable pricing for customers. The 3-year limit could be extended if deemed desirable and if counterparties are found who meet risk and credit standards.

- The company's supplies are in balance with firm demand under "design day" peak conditions (coldest weather in the last 20 years). Accordingly, new storage and/or pipeline resources must continue to be added each year to meet expected firm load growth. However, price elasticity issues have materialized in the last couple of years such that load growth may be significantly more or less than customer growth would indicate, depending on the direction of future rate changes.

- The expansion of Mist for interstate (off-system) customers fits well with the company's resource decision-making as it avoids some of the "lumpiness" that typically accompany resource additions, allows for "just in time" recall of capacity, and virtually eliminates the development risks associated with storage expansions.

- The company's service territory is widespread and it is not practical to consider tying together all of NW Natural's customers into a single integrated distribution system. Accordingly, some amount of incremental upstream pipeline capacity may be needed to serve the more isolated portions of the company's system.

- Conversely, as the cost of upstream pipeline expansions increase, it may be cost-effective for NW Natural to remove bottlenecks and more fully integrate certain portions of its own distribution system.

- The need for supply diversity has been underscored by the ruptures and resulting federal order in 2003 that Northwest Pipeline Corporation (NPC) must replace its 26" mainline from the Canadian border to NW Natural's service territory by December 2006. Cost-effective opportunities to improve supply path diversity should be pursued.

III. CURRENT RESOURCES

A. PIPELINE TRANSPORTATION CONTRACTS

NW Natural holds firm transportation contracts for capacity on the Northwest Pipeline Corporation (NPC) interstate pipeline system, over which all supplies must flow during the year except for the small amount of local gas produced in the Mist field (currently less than 1% of annual requirements). For its purchases in Alberta and British Columbia, NW Natural also holds transportation contracts on the pipeline systems upstream of NPC, namely Gas Transmission Northwest (GTN, formerly known as PGT and about to become a unit of TransCanada Pipelines Limited), TransCanada's BC System (TCPL-BC, formerly known as ANG), TransCanada's Alberta System (TCPL-Alberta, also known as NOVA), Westcoast Energy Inc. (WEI, a division of Duke Energy) and the Southern Crossing Pipeline owned by Terasen Inc. (formerly known as BC Gas).

NW Natural holds all rights to most of its firm transportation contracts. The exception is one small volume NPC contract that was acquired by NW Natural from another party who retained the right to re-acquire the contract at a future date. Similarly, NW Natural has released a small portion of its NPC capacity to two customers but has retained certain heating season recall rights. Details of each contract are provided in Table B-1.

Table B-1

Firm Transportation Capacity as of November 2004

Pipeline and Contract	Contract Demand (therms/day)	Termination Date
NPC:		
Sales Conversion	2,148,890	09/30/2013
1993 Expansion	351,550	09/30/2013
1995 Expansion	1,020,000	12/01/2011
Capacity Acquisition #1	52,000	12/31/2005
Capacity Acquisition #2	50,000	03/31/2008
Total NPC Capacity	3,622,440	
Less recallable releases to -		
Customer Release#1	(300,000)	10/31/2010
Customer Release#2	(70,000)	10/31/2004
Net NPC Capacity	**3,252,440**	
GTN:		
Sales Conversion	36,160	10/31/2023
1993 Expansion	465,490	10/31/2023
1995 Rationalization	560,000	10/31/2005
Total GTN Capacity	**1,061,650**	
TCPL-BC:		
1993 Expansion	470,000	10/31/2008
1995 Rationalization	565,000	10/31/2005
Capacity Acquisition #3	38,140	11/01/2008
Capacity Acquisition #6	482,000	10/31/2016
Total TCPL-BC Capacity	**1,555,140**	
TCPL-Alberta:		
1993 Expansion	475,000	10/31/2008
1995 Rationalization	570,000	10/31/2005
Capacity Acquisition #4	38,610	10/31/2008
Capacity Acquisition #7	489,100	10/31/2016
Total TCPL-Alberta Capacity	**1,572,710**	
WEI	**600,000**	10/31/2014
Southern Crossing Pipeline	**472,000**	10/31/2020

Notes to Table B-1:

1. All of the agreements continue year-to-year after termination, at NW Natural's sole option, except for Capacity Acquisition #1 and Customer Releases #1 and #2. Each of those parties has the option to continue their respective agreements with NW Natural.
2. The TCPL-BC and TCPL-Alberta contracts are denominated in volumetric units. Accordingly, the above energy units are approximations.
3. The numbers shown for the 1993 Expansion contracts on GTN and TCPL-BC are for the winter season (October-March) only. Both contracts decline during the summer season (April-September) to approximately 300,000 therms/day.
4. Capacity Acquisitions #3 and #4 were made to match downstream capacities on the GTN system.
5. Capacity Acquisition #5 is WEI T-South capacity from Station 2 to Sumas.
6. Capacity Acquisitions #6 and #7, along with the Southern Crossing Pipeline contract, are aligned to transport gas from Alberta to Sumas commencing November 1, 2004.
7. NW Natural also has a 2,500,000 therm/day interruptible NPC contract with a monthly evergreen term.
8. The NPC Sales Conversion contract demand originally totaled 2,460,440 therms/day. The 1993 Expansion contract demand originally totaled 500,000 therms/day. Portions of each were permanently assigned to a customer in 1995 as part of a transaction that also included the recallable capacity and supply listed in the table as Customer Release #1.

Since the implementation of FERC Order 636 in 1993, capacity rights on U.S. interstate pipelines have been commoditized; *i.e.*, capacity can be bought and sold like other commodities. These releases and acquisitions occur over electronic bulletin board systems maintained by the pipelines, under rules laid out by FERC. To further facilitate transactional efficiency and a national market, interstate pipelines have moved towards some standardization of definitions and procedures through the efforts of the industry-supported North American Energy Standards Board (NAESB), with the direction and approval of FERC. Capacity trades also can occur on the Canadian pipelines. In general, Canadian pipelines try to be consistent with most of the NAESB standards since much of the Canadian gas production is destined by export to markets in the United States.

On the pipeline systems utilized by NW Natural, usage among capacity holders tends to peak in roughly a coincident fashion as cold weather blankets the Pacific Northwest region. Similarly, capacity that may be available during off-peak months tends to be available from many capacity holders at the same time. This means that, unfortunately, NW Natural is rarely in a position to release capacity during high value periods of the year, and it would be unusual for capacity to be available for acquisition during peak load conditions. Given the dynamics of market growth and pipeline expansion, the company will continue to monitor and utilize the capacity release mechanism whenever appropriate, which primarily will mean continuing to post its own capacity for release during off-peak periods to benefit its customers.

B. GAS SUPPLY CONTRACTS

NW Natural's portfolio of supply for the 2004-2005 heating season is indicated in Table B-2. The contracts with near-term expiration dates will either be renegotiated or replaced prior to the next heating season. The contracts are baseloaded, meaning they have a daily delivery obligation, unless labeled as “Swing Supply,” which means NW Natural has a daily option to take all, some or none of the indicated volumes at its discretion.

Table B-2

Upstream Supplier Portfolio as of November 2004

Supply Location/Type	Contract Demand (therms/day)	Termination Date
British Columbia/year-round	300,000	10/31/2008
British Columbia/year-round	200,000	10/31/2005
Alberta/year-round	100,000	10/31/2014
Alberta/year-round	100,000	10/31/2009
Alberta/year-round	100,000	10/31/2008
Alberta/year-round	100,000	10/31/2006
Alberta/year-round	250,000	10/31/2005
Alberta/winter-only:		
Nov – Mar	50,000	3/31/2006
Dec – Feb	150,000	2/28/2006
Nov – Mar	200,000	3/31/2005
Nov – Mar (Swing Supply)	250,000	3/31/2005
Rockies/winter-only:		
Nov – Mar	580,000	3/31/2005
Nov – Mar (Swing Supply)	600,000	3/31/2005
Total Off-System Firm Contract Supply	2,980,000	

Notes:
1. Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to the reduction for upstream pipeline fuel consumption.
2. Differences between contracted supply quantities and firm pipeline capacity amounts held by NW Natural represent opportunities for short-term (spot) gas purchases.

3. Almost all term contracts contain a price formula tied to a published monthly index price. Those index prices are hedged using financial instruments.

C. STORAGE OPTIONS

The key characteristics of existing storage options available to NW Natural from its own facilities, or contracted from NPC on a firm basis, are shown in Table B-3[1]:

Table B-3

Firm Storage Resources as of November 2004

Facility	Maximum Deliverability (therms/day)	Maximum Seasonal Capacity (therms)	Termination Date
Jackson Prairie:			
SGS-2F	460,300	11,202,880	10/31/2005
TF-2 (redelivery service)	326,240	8,390,460	10/31/2005
TF-2 (redelivery service)	134,060	2,812,420	03/31/2008
Plymouth LNG:			
LS-1	601,000	4,789,000	10/31/2005
TF-2 (redelivery service)	601,000	4,789,000	10/31/2005
Total Firm Off-system Storage:			
Withdrawal/Vaporization	1,061,300	15,991,880	
TF-2 Redelivery	1,061,300	15,991,880	
Firm On-System Storage Plants:			
Mist (reserved for core)	2,300,000	89,000,000	n/a
Portland LNG Plant (Gasco)	1,200,000	6,000,000	n/a
Newport LNG Plant	600,000	10,000,000	n/a
Total On-System Storage	4,100,000	105,000,000	
Total Firm Storage Resource	**5,161,300**	**120,991,880**	

Notes:
1. All of the above agreements continue year-to-year after termination at NW Natural's sole option.
2. On-system storage peak deliverability based on design criteria.

The storage deliverability and seasonal capacity shown in Table B-3 for the Mist underground storage facility represents NW Natural's portion of the present design capacity. It does not include any capacity pre-built for the eventual use of core customers that is currently used for off-system storage service.

D. OTHER EXISTING SUPPLY RESOURCES

As mentioned previously, an additional type of resource in NW Natural's portfolio is a variation on storage, *i.e.*, agreements that allow the company to utilize gas supplies delivered to the company's service territory for a limited number of days during the heating season. These are supplies that otherwise would be consumed at industrial sites in the company's service territory. NW Natural currently has four such "recall" arrangements with three parties, as summarized in Table B-4 below.

Table B-4

Recallable Supply Arrangements as of November 2004

Name	**Maximum Daily Rate (therms/day)**	**Maximum Days per Heating Season**	**Termination Date**
Recall 1	300,000	30	11/01/2010
Recall 2	70,000	35	10/31/2005
Recall 3A	50,000	40	01/01/2005
Recall 3B	30,000	40	11/01/2005
Total Recallable Supply	**450,000**		

All of the above agreements provide for continuation after the termination date if mutually acceptable. Three of these deals (Recall 2 and 3A/B) are already in their annual "evergreen" period. The first two arrangements (Recall 1 and 2) utilize NPC capacity released by NW Natural on a recallable basis, and correlate to customer release volumes shown in Table B-1. If and when those two arrangements terminate, the released NPC capacity reverts back to NW Natural. The other arrangements utilize NPC capacity held by the providers of the service.

The pricing of the recallable supplies reflects the peaking nature of the service. The incremental price of any recalled supplies typically are tied to alternative fuel costs (diesel, propane, etc.), and so would not be economic to dispatch until anything other than extreme cold weather conditions.

There is one additional supply resource, albeit a small one, available to NW Natural that is not covered above. This is the native gas production in the Mist field.

Since the initial gas discoveries in 1979, production flows have ranged up to roughly 100,000 therms/day. Local production now results from third party exploration efforts and currently runs less than 20,000 therms/day. All such production is sold under a long-term contract to NW Natural for the life of the production wells. Due to the relatively low Btu content of the production gas, volumes almost always must be blended with the company's other supplies to reach an acceptable heating value. This limits the amount of production gas the company can receive, and so the amount mentioned above is not likely to change significantly unless higher Btu gas discoveries are made or markets for lower Btu gas can be found.

E. SUPPLY DIVERSITY

The company buys its supplies from a variety of supply basins, including a small amount of local production in the Mist field as mentioned above. The underlying purchase contracts are weighted towards medium and longer (1-10 year) durations to ensure reliability of supply and simplify contract administration. A significant number of the contracts are short-term (less than 1 year but greater than 1 month) arrangements, primarily five-month contracts, to match the seasonal increase in customer requirements during the winter. A small portion is purchased on the spot (1 month or less) market, typically during the non-heating season to meet fluctuating storage injection requirements and if favorable pricing is available during other periods of the year.

Figures B-1 and B-2 provide graphical representations of the company's supply resources and diversity in 2004:

FIGURE B-1

Gas Supply Diversity – By Contract Length
Based on Calendar Year 2003 Purchases

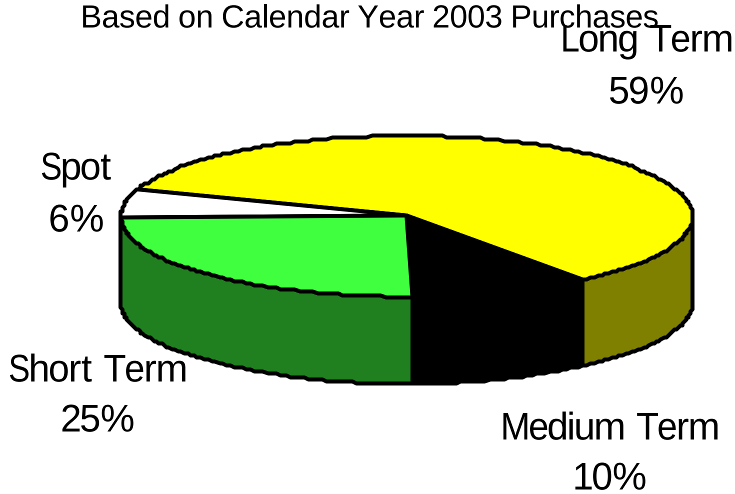
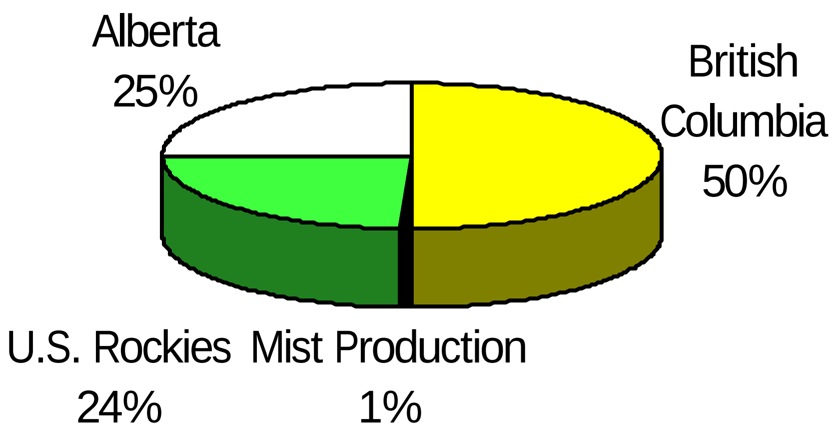


FIGURE B-2

Gas Supply Diversity – By Source
Based on Calendar Year 2003 Purchases



While not appreciably different from earlier years, two transitions began in 2003 that will alter the appearance of these graphs in future years.

First, the company had five long-term (10-15 year) supply contracts that all expired in October or November 2003. These contracts previously accounted for over 60% of total annual purchases. They began during the onset of deregulation in the late 1980s and early 1990s and reflected concerns at the time regarding supply reliability, as well as regulatory requirements to demonstrate market support for upstream pipeline expansions. They were cumbersome, however, in that they required annual price renegotiation subject to binding arbitration. Over time, these contracts evolved to using price formulas based on monthly price indexes, but annual renegotiation was still needed every year to determine the factor (usually a small premium) to be applied to the monthly index for the coming year.

The replacement supply contracts that began in late 2003 also reference monthly price indexes, but the factor to be applied to the index has been negotiated for the term of the agreement, so no further negotiations are required. These contracts generally have durations between two and ten years, which fall in the "Medium Term" category in Figure B-1. Accordingly, over the next couple of years, the "Long Term" category should shrink considerably while the "Medium Term" category expands.

The second transition concerns sources of supply. While traditionally dependent on British Columbia for roughly half of its gas purchases, there are far greater supplies of gas available in the province of Alberta. While prices may be more or less favorable at times, Alberta markets are far more liquid and hence exhibit less volatility than British Columbia trading points. NW Natural's subscription to capacity on SCP and associated TCPL capacity will allow it to shift roughly 30% of its current British Columbia purchases to Alberta starting in November 2004. Therefore, for calendar year 2005 and beyond, the numbers in Figure B-2 should show growth in the "Alberta" number and a decline for "British Columbia," so that those two categories should be much closer in size.

As supply contracts expire, new opportunities to re-contract supplies under different arrangements will be examined.

IV. SUPPLY-SIDE RESOURCE DISPATCHING

The company uses a gas supply dispatch model each Fall to determine how supplies should be dispatched on a daily basis from various pipeline supplies and storage facilities. The objective is to ensure reliable service during the heating season and, at the same time, achieve the maximum economic benefit from seasonal price differences and varying gas delivery terms. This seasonal dispatch model supports the Gas Supply Department's daily operations, and should not be confused with the linear programming (LP) model discussed in Chapter D. The LP model is utilized by the Rates Department for long-range (multiple year) planning, and it does not produce the daily detail of the dispatch model. NW Natural constantly works to maintain consistency between these two models as appropriate.

In the dispatch model, supply resources with 365 days of deliverability at the full daily limit are generally utilized first. Resources with the least number of days of deliverability are generally dispatched last[2]. If suppliers perform as contracted, if pipelines and storage facilities operate as expected, and if customer behavior and loads do not exceed expectations, then reliability will be ensured.

Winter supply dispatching has been designed around a forecast of temperature patterns that aggressively anticipate severe increases in customer gas requirements. The weather pattern reflects the coldest overall heating season in any one year over the past twenty years, augmented slightly to include the single coldest day over that same 20-year period. Using this "design winter" temperature pattern, NW Natural's dispatch model develops inventory curves representing the ideal operation of each storage facility to meet core customer demand.

This approach guides operating personnel by simulating the effects of our dispatch choices on subsequent heating season conditions. If storage inventories threaten to fall below targeted levels, more expensive peaking supplies might be dispatched to slow or halt storage withdrawals. Peaking supplies may also be used to replenish depleted stocks to ensure reliable operations over the rest of the winter. Another option is for the company to curtail its interruptible sales customers, in effect reserving supplies for later use by firm customers. Of course, as the heating season unfolds, weather forecasts provide some insight as to whether design weather is truly forthcoming, and the storage inventory guidelines may be relaxed accordingly.

Appendix B includes a set of graphs at pp. BB-1 through BB-5, showing target ("plan curve") and actual inventory levels for the 2003-2004 heating season at Mist, the Newport LNG plant, the Portland LNG plant ("Gasco"), and under the Jackson Prairie (SGS-2F) and Plymouth (LS-1) contracts with NPC. Inventory levels dropped sharply at the LNG plants due to the record sales experienced during the cold weather in early January, but because of generally warmer weather during most of that winter, concerns about inventory targets were mitigated.

When the weather is not as severe as the design winter, the actual dispatch of supplies may change. For example, storage gas that had been obtained at lower prices may be used first, displacing higher priced contract supplies. Ideally, storage gas supply inventories are maintained at all storage facilities at or above the levels indicated by the dispatch simulation model to ensure high reliability of service to the company's firm sales customers.

It should be pointed out that in the Company's supply acquisition and dispatch strategies, state boundaries play no role. The system is operated as an integrated whole and costs are apportioned accordingly. For example, on a day when temperatures drop and loads increase across the system, the total expected shortfall in supply may be satisfied by dispatching additional gas from Mist storage. The supplies from Mist physically can flow only to NW Natural's customers in the Portland metro area. Since the amount withdrawn equals the total system shortfall, this means an excess of Mist gas flows into the Portland area. This excess flow acts to displace some of NW Natural's pipeline deliveries to the other points that also need additional supply, such as those in the Company's Washington service territory. In the end, Mist gas is essentially received by these non-connected customers by such displacement, and costs are allocated in the same manner. The company's operations as described are consistent with its Hinshaw Exemption from the Natural Gas Act.

V. RECENT RESOURCE DECISIONS

Included in the company's portfolio of current gas supply are resources added since the development of the company's 2000 IRP in response to continued robust customer growth, and in anticipation of future growth. These additions generally followed supply-related conclusions and action plan steps developed in the 2000 IRP, as follows[3]:

2000 IRP Conclusion No. 2:
"The company's existing resources are in balance with loads. Therefore, beginning almost immediately the company must add resources to assure service under peak load conditions."

2000 IRP Conclusion No. 3:
"Development of underground storage and associated pipeline take-away capacity (the South Mist Pipeline Extension) is the least-cost means of meeting our service area's growing requirements. Storage and related pipeline infrastructure will save customers $253 million[4] when compared to the next most advantageous resource."

2000 IRP Action Plan 2.1:
"Develop Mist Phase IV which includes the 24" South Mist Pipeline Extension (SMPE) from Bacona to Sherwood Oregon by November 2002 or earlier if possible, develop associated storage reservoirs, and additional compression at Miller Station."

2000 IRP Action Plan 2.2:
"Develop Mist Phase V which includes the 24" SMPE from Sherwood to the Molalla Oregon gate station by November 2004 or earlier if possible, and develop associated reservoir deliverability increases."

2000 IRP Action Plan 2.3:
"Develop Mist Phase VI which includes reservoir deliverability increases."

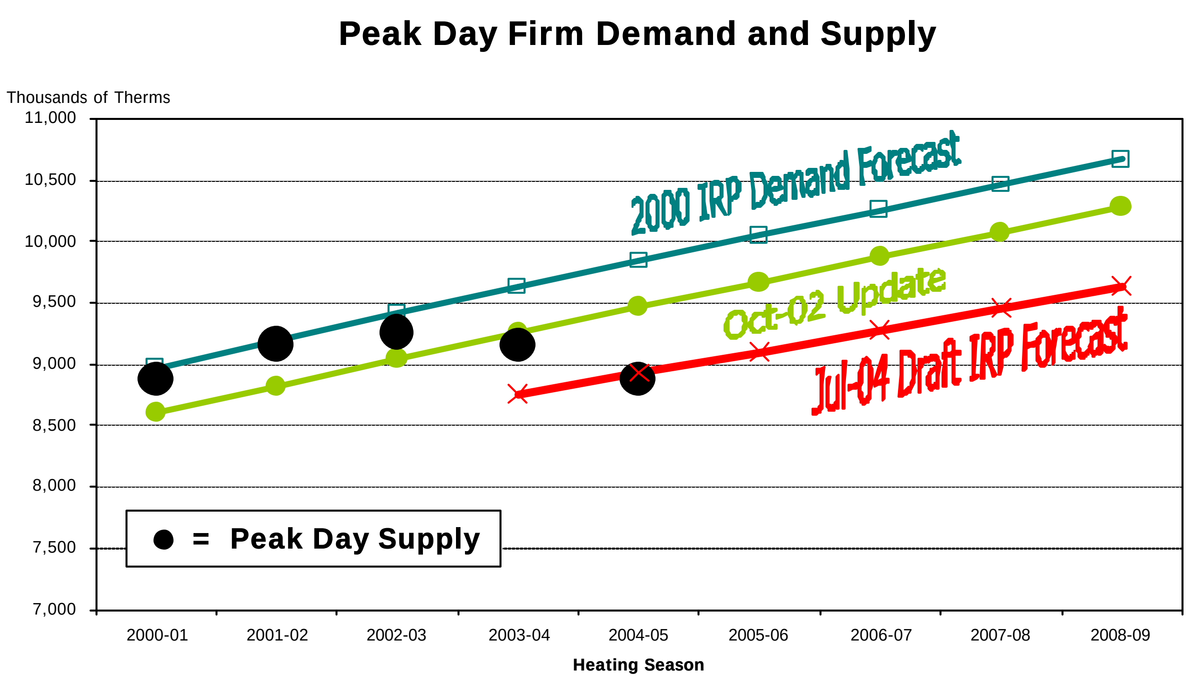
2000 IRP Action Plan 2.4:
"Explore opportunities for storage development beyond core market requirements."

Prior to 2003, the last increment of Mist expansion completed for core customers was a project that, in late 1999, added almost 28 miles of 24" piping to loop the existing South Mist Feeder from Miller Station to a point at the western edge of the Portland metropolitan area (referred to above as Bacona). While reservoir and Miller Station additions and improvements subsequently were made, the capacity had to be marketed to interstate (off-system) customers due to the extended length of the authorization process for SMPE, which did not receive final permission to be built until November 2003.

The first segment of SMPE was completed in late 2003. Rather than follow the original plan of working from north to south, a 12 mile section instead was built from the southern terminus at the Molalla gate station to its first interconnection further north with the company's high pressure distribution system near Aurora. This connection allowed higher flows and pressures from the NPC system, which were critical to that southern portion of the Portland-area distribution system during the cold weather event experienced in early January 2004.

The remaining 50 miles of SMPE was completed in the Fall of 2004, finally allowing the company to access more Mist deliverability. This will mark the first "recall" of Mist capacity developed in advance of core need, which had been marketed to the interstate market during the past three years. Resources needed to bridge the gap until SMPE is completed, including baseload deliveries of supplier gas at the "citygate" and other peaking arrangements, have or will be allowed to terminate. The resulting pattern of load forecasts and peak day supplies since the 2000 IRP are shown in Figure B-3:

Figure B-3



Other resource decisions since the 2000 IRP involved further diversification of the company's upstream supplies through subscriptions to the WEI and SCP capacity mentioned above. This did not change aggregate supplies but allowed sourcing to move from Sumas to more liquid trading points at Station 2 in northern British Columbia, and within Alberta at the hub known as AECO/NIT. While overall supply costs are expected to be impacted little or none from such movements, volatility is expected to be lower since significantly more gas trading occurs at AECO/NIT, and Station 2 purchases can be more readily indexed to AECO/NIT prices than can supplies at Sumas.

VI. FUTURE RESOURCE ALTERNATIVES

NW Natural is now considering resource options including new interstate pipeline capacity, continued storage development, imported LNG, and hybrids of these three basic approaches. The primary alternatives are described in more detail below. Most of these options will be evaluated in Chapter D using a linear programming model.

A. INTERSTATE CAPACITY ADDITIONS

Capacity additions can span a wide range of lead times between a pipeline's decision to conduct an open season and the completion date of the constructed facilities, but as a rough approximation, the process takes about three years from start to finish. This includes the canvassing of market interest and contracting through an open season process, permitting with federal and other authorities, and the actual design and construction of the facilities, with some of these steps overlapping. For example, NPC currently has a project to replace its idled 26" mainline in western Washington state. The process began in Spring 2004 and is expected to be completed in November 2006.

Similarly, other upstream pipelines, such as GTN, periodically hold open seasons or have uncontracted capacity available for sale. Since NW Natural is only interconnected to NPC, a subscription to more NPC mainline capacity would tend to be a prerequisite to hold more upstream capacity of equivalent amount. An exception may be where market dynamics indicate some advantage to NW Natural to hold more, less or different upstream capacity than it currently does. As upstream pipelines continue to expand into new supply regions and/or to serve new markets, an evolution of trading hubs may occur. New, more liquid, trading points may emerge while others fade into disuse. Accordingly, it may be to NW Natural's benefit to hold transportation capacity leading to such points.

An example of this would be if an LNG import terminal was sited somewhere along the coast of the Pacific Northwest or British Columbia. In that case, if the supplies were cost-effective, NW Natural might have to re-configure some of its upstream pipeline contracts and/or add new pipeline contracts to access those supplies. Similarly, the possibility of new gas pipelines transporting supplies from the Arctic Circle (North Slope of Alaska and the Mackenzie Delta) south to British Columbia or Alberta might require some changes if those supplies are not delivered to the AECO/NIT hub or to Station 2. Again, analysis would be needed to determine the most reliable and cost-effective combination of upstream pipeline contracts. However, since LNG import terminals in the Pacific Northwest and pipelines from the Arctic Circle are very speculative at this moment, and it will be many years before either could become reality, that analysis is not part of this IRP.

B. MIST STORAGE EXPANSION

NW Natural's core customers currently receive underground storage service at its Miller Station facility from three depleted production reservoirs (Bruer, Flora, Al's Pool) in the Mist field, with a portion of a fourth reservoir (Reichhold) about to be recalled for core use in Fall 2004. Mist is ideally located in the midst of NW Natural's service territory, eliminating the need for upstream interstate pipeline transportation service to deliver the gas during the heating season.

Expansion and diversification of Mist storage will continue to be NW Natural's primary focus for its supply portfolio growth. While storage is generally well suited to meeting the incremental load requirements generated by new space heating customers, Mist is exceptional due to its location within the company's service territory. Its proximity to the Portland metro area, where the majority of the company's firm load growth lies, avoids the need for winter season redelivery over the interstate pipeline system. This both reduces costs and enhances reliability.

Advances such as 3D seismic imaging and horizontal well drilling have shown that new reservoirs can be added with more deliverability at lower cost as compared to the original storage development in the late 1980s. These techniques are now being applied to the original storage reservoirs (Bruer and Flora) to improve their deliverability at low cost. At the time of the 2000 IRP, further expansion of Mist appeared to be limited not by the geology of the field, but only by the timeline NW Natural had to follow to construct the delivery pipelines it needs to utilize such supplies. With the completion of SMPE in late 2004, that major bottleneck will have been removed.

Adding more NPC capacity to NW Natural's service territory also carries with it the requirement that the company invest in distribution system reinforcements from its NPC gate stations. So, to some extent, investments in Mist infrastructure can offset similar types of costs involved in any NPC capacity subscription options. A discussion of these infrastructure projects is provided in the next section. Some of the existing opportunities to expand storage at Mist are as follows:

1. More I/W Capacity in Bruer/Flora. As mentioned above, storage at Bruer and Flora was constructed in the late 1980s using then-existing techniques and operating/market assumptions. Using the latest data and technology, additional injection/withdrawal (I/W) wells could be drilled into Flora and Bruer to allow higher injection and withdrawal rates. A higher withdrawal rate offers the obvious advantage of greater use of the stored gas as a peaking resource, thereby displacing short-term, high-priced alternatives such as winter spot gas purchases.

Achieving a higher injection rate may allow NW Natural to better time its storage refill gas purchases to take full advantage of favorable spot gas pricing periods. However, this must be balanced against the need to ensure full refill during the off-peak months, as well as the higher equipment costs (capital and O&M) needed to accommodate wide fluctuations in refill rates.

2. More Seasonal Capacity in Bruer/Flora. After they were depleted of production gas in the early 1980s, the Bruer and Flora pools sat relatively empty for about two years before the introduction of storage gas was permitted. During this period, about half of the working gas capacity was lost to encroaching underground water. Experiments at a test reservoir (Busch) have shown that it is possible to reclaim some of a lost reservoir's capacity by gradually pushing the water out of the reservoir through gas injections at pressures above that originally found in the structure. This operation is referred to as "delta pressure" and it requires certain permit and equipment modifications. The company has been conservative in its delta pressure operations by going no more than 10% above the original discovery pressure. The Busch reservoir was successfully reactivated through delta pressure after losing all of its reservoir capacity to water in the late 1980s. Delta pressure is now being used at Bruer and Flora as a low cost method for enlarging the seasonal storage capacity available to NW Natural at Mist.

3. New Market Area Storage. NW Natural believes that the pricing of new pipeline capacity, with straight fixed-variable (SFV) rate design for firm transportation services, will continue to foster interest among gas users toward acquiring storage services. The company currently has three reservoirs (Reichhold, Schlicker and Busch) either partially or totally developed for such marketing efforts.

Over 40 production reservoirs have been discovered in the Mist field. Many of these other pools are now depleted or nearly depleted, and a large portion of them may be suitable for conversion to storage use. Storage development rights are held or controlled by NW Natural, but negotiations are still necessary with local land and mineral owners, which could delay or forestall such developments. Accordingly, NW Natural will continue to monitor other storage resources in the market area that may be available for development. For example, the owners of Jackson Prairie contemplate further expansion of their storage facilities, and other parties in the past have actively evaluated the feasibility of storage development at various locations in the Pacific Northwest.

Although some of the developable Mist reservoirs have been used in this IRP analysis, NW Natural does not assume that all of these storage resources must be developed at Mist. Rather, the Mist resources have been used as placeholders in this IRP because their development costs are somewhat known. They are thus proxies for the characteristics and costs of future storage resources. If competitive alternatives were made available at Jackson Prairie, or at other storage sites in our region as may be developed, they could be substituted for the Mist reservoirs analyzed in Chapter D.

C. PORTLAND-AREA INFRASTRUCTURE ADDITIONS

Whether from Mist or from the company's numerous gate station interconnections with NPC, any increase in resources to meet load growth must be accompanied by system expansions or reinforcements, the "backbone" of NW Natural's distribution system.

The evaluation of infrastructure requirements associated with either increased NPC deliverability or Mist storage development uses a network flow analysis model. Gas requirements at delivery nodes are projected based on observed flow rates during recent cold weather episodes. These flow rates are then adjusted to match design peak weather conditions and the effects of customer growth. Alternative system reinforcement strategies are then evaluated in terms of cost and ability to meet future gas requirements.

The 2000 IRP devoted considerable discussion to the various distribution system options associated with moving additional gas from Mist to Portland and surrounding area customers. With the SMPE completed, future internal infrastructure decisions will revolve around two key considerations: 1) the impact on the company's pipeline system design, reinforcement and replacement projects from the 2002 federally-mandated Integrity Management Program (IMP) and other similar state approved programs regarding bare steel pipeline and geo-hazard mitigation; and, 2) alternatives for moving Mist and Newport storage gas to customers outside the current confines of the Portland-area and northern Willamette Valley distribution systems, respectively.

IMP and similar programs continue to evolve but compliance is likely to require significant infrastructure investment over the next ten years. Those programs have been and will continue to be the subject of separate proceedings with state regulators and will not be further discussed here, but any infrastructure conclusions reached in the IRP will require further analysis to ensure congruence with the various integrity programs.

The focus of the next two sections will be options for moving storage gas to areas traditionally beyond their reach.

D. MOLALLA HUB

With SMPE in place, its point of interconnection with NPC's Grants Pass Lateral will be near the town of Molalla, Oregon, south of the Portland metro area. With the addition of compression at or near that point, gas from Mist via the SMPE could be increased in pressure sufficient to enter NPC's system. Since gas flows from north to south on the Grants Pass Lateral, it should be possible to move Mist supplies northward without need for any NPC expansion, or southward in lieu of Grants Pass Lateral expansions between Washougal and Molalla. Either way, the creation of a "hub" at the Molalla gate station may create cost-effective opportunities for NW Natural to move more Mist supplies to more remote load centers, whether in east Multnomah County, down the Willamette Valley, or through displacement, north to our Washington service area.

NW Natural has discussed these options with NPC and confirmed the feasibility of this alternative. Since the Molalla gate station required re-building as part of SMPE, it has been re-designed to easily accommodate gas flows from SMPE into NPC. If NW Natural takes the step to install compression and certain gas measurement equipment at Molalla, NPC need only make minor valve changes at its Oregon City Compressor Station to allow volumes to flow northward, and no changes to allow gas to flow southward.

Gas flowing down the Grants Pass Lateral is odorized by NW Natural at Washougal under a long-standing arrangement with NPC. De-odorizing the gas received at Molalla will not be required by NPC as long as the flow does not exceed volumes moving south through Washougal. Essentially, NPC will allow volumes into its system at Molalla to the extent they offset (displace) volumes flowing south from Washougal. NPC will not allow any additional volumes at Molalla unless NW Natural agrees to de-odorize this gas at

Washougal before it flows into the NPC mainline. While de-odorizing gas is a simple process, it currently is very costly, so the IRP analysis has not considered any scenarios of flow volumes at Molalla exceeding that of NW Natural's customer loads served off the Grants Pass Lateral.

E. NEW PIPELINE FROM NEWPORT

The daily deliverability of the Newport LNG plant is modeled at 600,000 therms/day due to load limitations. That is, the market areas served by the Newport plant (from the town of Newport north to Lincoln City and then east to Salem) have peak loads ranging up to about 600,000 therms/day. However, the Newport plant has all the equipment necessary to vaporize and send out up to 1 million therms/day. To reach that 1 million therm/day capability, infrastructure additions are needed to connect more load centers (*e.g.*, Corvallis/Albany, Eugene) to the Newport plant.

The additional piping and upgrading required to reach new load centers could be quite costly due to geographical constraints. This cost, though, could be competitive versus a subscription to additional upstream pipeline capacity, which also would need to be accompanied by distribution system reinforcements to serve customers increasingly distant from NPC's gate stations.

F. WILLAMETTE VALLEY FEEDER

This project involves new piping to move gas from Mist south to the Salem area and then continue further south to Albany and potentially even the Eugene area. This project could work in conjunction with a new pipeline from Newport as described above.

This project would be an alternative to continued expansion of NPC's Grants Pass Lateral, which transports gas to NW Natural's system throughout the Willamette Valley. In the past it was thought that this project would only proceed if environmental, civic, or other pressures significantly increase the cost or time needed to expand NPC's lateral. However, the company has enhanced portions of its pipeline from Portland to Salem over the past few years in the course of routine replacement activities (leakage repair, road grading projects, etc.), and would expect to continue these activities in the future as well as implement additional projects through the integrity management programs mentioned above.

Because of the project-specific nature of the company's pipeline integrity programs, a specific segment of a Valley Feeder project, for example, from Albany to

Eugene, could become cost-effective in lieu of incremental NPC capacity between those two locations. For this reason, the Valley Feeder and NPC capacity options have been segmented in the IRP analysis. Four segments have been considered: SMPE to McMinnville, McMinnville to Salem, Salem to Albany, and Albany to Eugene. Costs for these segments have been compared to the incremental costs of expansion of the equivalent segments on NPC's Grants Pass Lateral, as well as to the strategic placement of satellite LNG storage discussed below.

VII. ADDITIONAL SUPPLY-SIDE OPTIONS CONSIDERED

A. SATELLITE LNG AND PROPANE-AIR SYTEMS

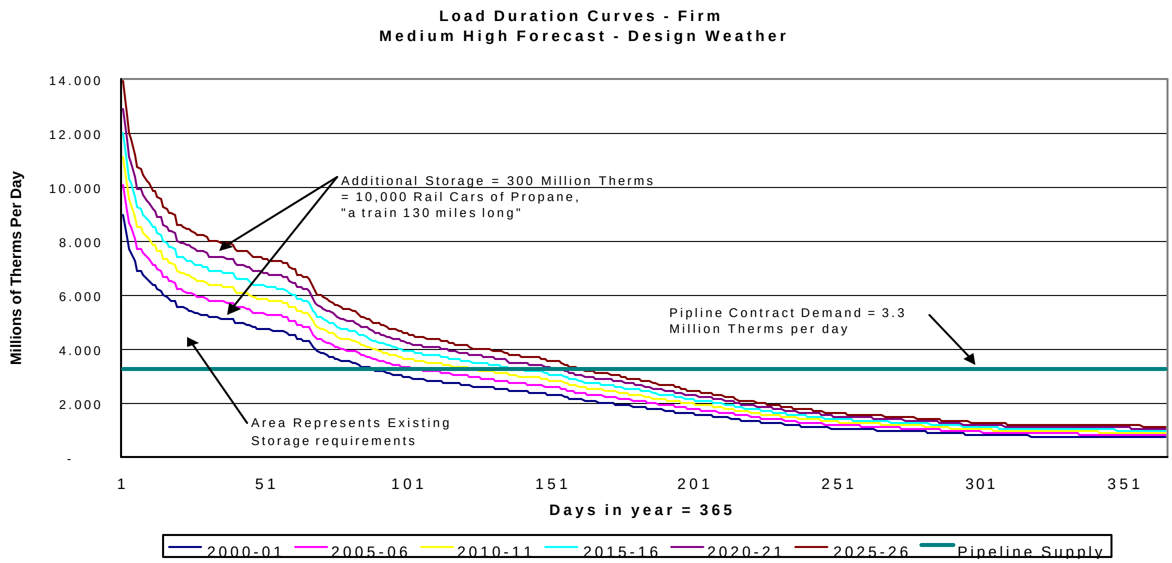
Some gas utilities rely on satellite LNG tanks to meet a portion of their needle-peaking requirements. The concept is that a small tank serving a remote area would be filled with LNG as winter approaches, and the site manned during cold weather episodes when vaporization is required. Since there is no on-site liquefaction process, the facility is fairly simple in design and operation. Where peaking demands are sharpest, the addition of satellite LNG could defer significant pipeline infrastructure investments.

During the summer of 1998, NW Natural commissioned an intern to conduct a study of satellite LNG feasibility. As reported in the 2000 IRP, the study found that satellite LNG was, at best, a limited niche resource for NW Natural. First, to minimize siting and permitting costs, the tank size should be less than 70,000 gallons of LNG (about 58,000 therms). This means they can only serve small load centers. If a relatively large investment in pipeline infrastructure would otherwise be required, the cost of the satellite LNG facility may be economic. However, there was no excess liquefaction capability at the Portland LNG plant and only limited capability at Newport. Shipping in LNG from remote locations is cost-prohibitive. Expanding the liquefaction processes at either Gasco or Newport is not viable due to site certification considerations.

In recent years, however, control system improvements at the Newport LNG plant have improved liquefaction performance. Puget Sound Energy installed a satellite LNG facility near Gig Harbor, Washington, to help meet customer growth at the tail end of their distribution system. LNG from NW Natural was used to help fill the Gig Harbor tank, and this has renewed NW Natural's interest in evaluating this concept for remote areas where siting and zoning approvals are conceivable.

LNG and propane-air facilities are limited by their role as peaking resources since they only provide a few days of deliverability. Figure B-4 uses propane as an example to demonstrate the limitations of stored liquid gas as a broad-based winter season resource. In the final year of the 30-year forecast horizon, the energy equivalent of 13,000 railcars filled with propane is needed to meet cold weather gas requirements. The LNG or propane-air systems examined provide only a few railcars of energy supply and provide an insignificant contribution when compared to total working gas requirements.

FIGURE B-4



In this IRP, NW Natural has evaluated satellite LNG in two locations in the Willamette Valley, outside Salem and Eugene, as interim resources that might delay the incursion of more expensive pipeline projects.

B. SUPPLY BASIN STORAGE DEVELOPMENTS

Capacity has been available in new and existing production area storage facilities in Alberta, British Columbia, and in the U.S. Rocky Mountain region. While NW Natural has made periodic use of these facilities (especially in Alberta) to store off-peak gas and improve supply contract load factors, there are no plans for NW Natural to become involved on a long-term equity and contractual basis with any of these facilities. The stumbling block is the upstream pipeline transportation cost required to bring these supplies to NW Natural's service area. Since the supplies would be needed during cold weather episodes, only primary firm transportation service will suffice. Consequently, having gas stored in a supply area can only advantage NW Natural if winter/summer price differences are sufficient to offset storage facility usage charges.

Assuming NW Natural continues to expand Mist, utilization of upstream pipeline capacity and year-round supply contracts should improve because storage injection requirements will grow. This will further decrease the need for supply area storage. Due to these factors, supply basin storage will probably never be more than a year-to-year gas supply portfolio structuring option, rather than a long-term resource acquisition.

C. DIRECT CONNECTION TO GTN

This resource was originally contemplated as a new feeder that would transport approximately 1 million therms/day from GTN's system in central Oregon to NW Natural's distribution system, with the most probable delivery point being in the vicinity of Albany. NW Natural agreed to proceed with this project in January 1993. It then agreed with GTN to alter deliveries to Stanfield when NPC provided an alternative expansion project through the Columbia Gorge that was more cost-effective. The major factors considered in this decision were: (1) after further study, GTN's costs escalated to the point that separate ratemaking treatment and significantly greater exposure to NW Natural were possible; (2) it required that NW Natural build a Valley feeder between Portland and Albany to ensure movement of the GTN supplies to the load centers; and (3) the environmental impact of the Cascades crossing was greater than expected compared to NPC's new expansion. On the plus side, the project would have allowed direct pipeline-on-pipeline competition between NPC and GTN, creating strategic opportunities for future capacity additions.

This project has been revisited from time to time by GTN, who refers to it as their Oregon Lateral, and it could be revived in the future when current interstate pipeline obligations come up for renewal or other alternatives arise.

VIII. GAS SUPPLY PORTFOLIO ACQUISITION STRATEGY

The supply acquisition options currently available to the company to meet future core market requirements include (a) entering into long-term gas supply contracts with fixed prices or fixed escalators; (b) purchasing proven reserves in place in a specific geologic formation; i.e., prepaying for the gas supplies; (c) using short-term and spot market supplies; (d) using storage to improve contract load factors (and hence pricing), take advantage of summer/winter price differences, and offset pipeline capacity requirements; and (e) entering into recallable supply/capacity arrangements with marketers and/or industrial customers who can interrupt their usage or switch to alternate fuels during peak demand periods. For all of the above types of supply, a variety of financial instruments exist to hedge prices.

The company's current portfolio of gas supplies consists of firm gas supply contracts of multi-year duration with prices fixed each year, winter season supplies at market-based index pricing, and a small portion expected to come directly from the spot market. Most of the company's contract volumes have commodity prices determined by annual negotiations. In recent years, the use of derivative instruments negotiated with financial counterparties has risen in prominence. These derivatives have virtually replaced the process of negotiating fixed prices directly with suppliers for purchases lasting more than one month in duration. Instead, the physical suppliers are comfortable relying on pricing formulas tied to published monthly or daily index prices. Derivative instruments may be multi-year in nature, and also may include various levels of optionality.

NW Natural's procurement strategy also relies on a diversified approach to acquiring supply resources. This includes the 1995 expansion that allowed the company to access additional gas supplies from Alberta, a subscription to WEI T-South capacity in 2003 that shifted some purchases from Sumas to Station 2, and the commencement in November 2004 of service on SCP along with additional TCPL capacity, which shifts Sumas purchases to AECO/NIT. In the meantime, the company has maintained its historic reliance on supplies from the U.S. Rocky Mountain area.

This diversity increases supply reliability if and when the company must deal with any unplanned losses from suppliers or disruptions in upstream pipeline capacity. The IMP process mentioned above will impact all U.S. pipeline companies, and the 2003 ruptures on NPC highlight a vulnerability that NW Natural will seek to mitigate if possible. The greater focus on Alberta supplies also hedges possible future issues regarding supply availability, as Alberta is currently much more liquid than the B.C. market and in the future is the likely terminus of the first new pipeline moving gas supplies south from the Arctic Circle (Mackenzie Delta).

NW Natural also has and will continue to pursue relationships with third parties as appropriate to optimize the company's use of its supply portfolio assets. Such arrangements were well publicized in the gas industry in the late 1990s, but the demise of Enron and withdrawal from the market of large players such as Mirant, Aquila, Dynegy, Reliant and others, has re-emphasized the need for maintaining gas acquisition and related skills within the utility. Maintaining high reliability of service to the company's core customers now and into the future must be ensured before NW Natural would consider any type of asset management arrangement.

IX. EMERGENCY PLANNING

NW Natural utilizes the Incident Command System (ICS) methodology for managing emergency events. The company has a cross-departmental team, the Business Continuity Planning Management Committee (BCPMC), responsible for planning and coordinating the actions of field and office personnel during emergencies such as floods, earthquakes, windstorms, or severe cold weather. The Operations section of that team is prepared to take whatever actions are needed to prevent or minimize firm curtailments of service. This includes the operation of regulators to boost pressures, the installation of pipe to tie together sections of NW Natural's distribution system, the dispatching of two mobile LNG tankers to handle distribution system trouble spots, curtailment notices to interruptible customers, shut-offs and light-ups of firm customers, and public announcements to reduce gas usage.

The BCPMC conducts periodic exercises to ensure the readiness of the team and gain experience in ICS techniques. One of the most visible uses of ICS occurred during the Y2K rollover transition period. The company utilized Y2K as both a potential threat and an opportunity for a corporate-wide emergency readiness exercise, with over 300 employees involved in the process. More recent examples include two pre-planned and one unexpected outage of the power and phone systems at the company's headquarters building (One Pacific Square), which required transfer of customer service and gas control functions to the company's off-site back-up facilities.

As described previously, the company designs its resource portfolio to satisfy firm loads on the coldest-weather day and through the most strenuous heating season (as measured by HDDs) experienced during the past 20 years. However, these assumptions do not always hold true. First, design weather may not be the coldest faced by the company. There certainly have been colder heating seasons if a longer historical perspective is taken, such as occurred in 1949/50. Second, the Plan assumes perfect foresight of the weather. This may not be important for storage supplies, which can respond to load changes very quickly, but all other supplies require some amount of prior notice for scheduling. This ranges from two hours for curtailment of interruptible sales, to a day for the transportation of most pipeline gas and the use of special industrial customer capacity/supply recall arrangements. Finally, the Plan assumes perfect equipment behavior; i.e., nothing breaks or freezes up, even in the face of extremely cold temperatures.

Accordingly, the BCPMC has to contend with the failure of any or all of the above assumptions in addition to the stresses on the system caused by the emergency itself. NW Natural's ultimate goal is an emergency planning process that handles customer needs. NW Natural cannot guarantee uninterrupted service at all times to all customers, but the BCPMC works to make customer outages during emergency events as brief and painless as possible, with public health and safety being the ultimate priority.

X. LONG-RANGE DISTRIBUTION SYSTEM INFRASTRUCTURE REQUIREMENTS

The performance of the company's distribution system must continually be modified to meet changing customer demands. Planning for the expansion, reinforcement, and replacement of elements of the distribution system is performed by the company's Engineering Department working closely with elements of Construction and Marketing, with input from outside economic development and planning agencies.

The evaluation of infrastructure requirements associated with the expansion and interconnection of the distribution system and the development of underground storage uses a network flow analysis model. The company uses the Stoner Workstation Service (SWS) package of software, developed by Stoner Associates of Carlisle, Pennsylvania, for this purpose.

The SWS software provides the platform for digital computer simulation of transient gas flow behavior in any arbitrarily configured piping system. The analysis procedure calculates the time-varying flows, pressures, horsepower and other variables under scenarios that reflect actual service conditions. Studies are conducted to determine the response of the gas distribution system due to load changes, pressure set point changes, compressor performance changes, etc. The software is also sophisticated enough to enable the modeling of high-speed transient conditions, such as instantaneous valve closure and pipeline rupture.

The company has constructed models based on the SWS software that are designed to evaluate distribution system capacity constraints, inter-related flow characteristics, and pressure stabilization aspects of distribution system planning that are evaluated under steady-state and transient conditions. The model development process, previously a very tedious and time-consuming effort of manually constructing nodal networks and linking data, has been streamlined through the integration of geographically referenced system map information and company data sources to the SWS software. System maps from the Geographic Information System provide the physical distribution system data required for basic model construction. Load data is drawn from the Customer Information System and coupled with other system performance data from various information sources. This semi-automated data extraction process has helped to speed model construction.

The company can use the SWS models and software to evaluate performance of the distribution system under a variety of conditions. Typically the analysis is focused on meeting growing peak day customer demands while maintaining system stability. Gas requirements at delivery nodes are projected based on observed flow rates during recent cold weather episodes. These flow rates are then adjusted to match design peak weather conditions and the effects of customer growth. Alternative system expansion and reinforcement strategies are then evaluated in terms of system stability, cost, and ability to meet future gas delivery requirements. This computer simulation capability allows the company to efficiently evaluate distribution system performance in terms of stability, reliability, and safety under varying boundary conditions ranging from peak-day delivery requirements to temporary service interruptions, both planned and unplanned.

System planning takes place continuously, integrating new customer growth requirements into the company's construction forecasts. Computer simulation testing is used to help validate the need for and timing of specific system expansion, reinforcement, and replacement projects. Near-term (one to two-year) projects are highly likely to occur as specified to meet customer delivery requirements. Mid-term (three to five-year) projects are subject to time slippage based on adjustments to the rate and geographic direction of customer growth. Long-term (beyond five years) will tend to be general projections based on expected economic development of the region and gas supply resource acquisitions, and thus, subject to change.

END NOTES

1 SGS refers to the Storage Gas Service available from NPC at the Jackson Prairie underground storage facility near Chehalis, Washington. LS refers to the Liquefaction Service offered at NPC's Plymouth LNG plant in Washington, just across the Columbia River from Umatilla, Oregon. SGS-2F and LS-1 exclude NPC transportation service to NW Natural's system. TF-2 is the firm transportation service offered by NPC for redelivery of gas from certain storage facilities to customers on its system.

2 Although it is generally true that shorter-lived resources tend to have higher variable costs than longer-lived resources, there are sometimes exceptions to this rule that may cause a change in the dispatch pattern. For example, a supply resource with 75 days of deliverability may have a higher variable cost than a resource with 20 days of deliverability. If heating loads happen to be lower than expected in a given winter, then using the 20-day resource before the 75-day resource would be the least-cost alternative since the risk of jeopardizing firm service reliability is minimal. However, should heating loads be higher than expected, dispatching first the resources with the longer deliverability periods helps ensure reliability of service.

The notable exceptions to the variable cost rule of thumb stated above are the LNG facilities. For example, the Portland LNG facility ("Gasco") has both a low number of days of deliverability at full rate and the lowest variable cost of operation. Because of its location, the liquefaction of gas at Gasco is accomplished at almost zero cost by taking advantage of pipeline pressure differences within NW Natural's system. However, while its liquefaction cost is very small, Gasco's liquefaction rate is also very slow in comparison to other storage facilities. The operating situation is similar for the LS-1 liquefaction storage service provided by NPC. Consequently, because of their slow refill rates, Gasco and LS-1 are frequently among the last storage resources dispatched.

With these exceptions, the variable costs of operation decline as the number of days of deliverability increase for facilities in NW Natural's supply stack.

3 Conclusions reprinted from the January 2001 printing of NW Natural's 2000 Integrated Resource Plan, Volume 1, Executive Summary, pages ES-2 and ES-16.

4 This estimate was subsequently revised to $180 million. See OPUC Order 00-782 acknowledging the company's 2000 Plan at pages 2 and 3 of Appendix D.

CHAPTER C: DEMAND-SIDE RESOURCES

CHAPTER C: DEMAND-SIDE RESOURCES

I. OVERVIEW

In this Chapter, the terms Demand Side Management (DSM), Conservation, and Energy Efficiency (EE) are used more or less interchangeably.

The 2004 Plan marks a major change in the way the company deals with demand-side resources. Since publication of the 2000 Plan, a great deal has changed with respect to the company's approach to energy efficiency. The combination of the approval of a partial decoupling mechanism in the state of Oregon and the implementation of a public purpose funding mechanism administered by the Energy Trust of Oregon (ETO) allows the company to take a less active role in the development and delivery of conservation programs. At the same time, these developments align ratepayer and shareholder interests in the pursuit of energy efficiency.

Decoupling refers to the mechanisms developed in the Oregon UG 143 docket to partially sever the relationship between therm sales and revenues. It partially addresses the problems faced by a utility whose costs are essentially fixed but has revenues dependent on customers' gas consumption behavior.

Public purpose funds are collected from Oregon residential and commercial ratepayers and are used by the ETO to finance residential and commercial EE investments. In addition, funds are collected and used by the company to fund low-income weatherization and low-income bill payment assistance.

After the ETO has established a record and has been able to perform measurement and evaluation studies focused on gas EE programs and their performance, the company will attempt to implement the most highly cost effective programs in Washington using ETO energy service contractors, but not the ETO itself.

In the next IRP cycle, enough should be known about ETO program performance to allow the inclusion of ETO energy efficiency programs as a demand-side resources to be selected or rejected by the optimization model presented in Chapter D.

II. KEY FINDINGS

- For this IRP planning cycle the company adjusts its long-term demand forecast by the projected energy savings expected by the Energy Trust of Oregon without attempting to evaluate ETO conservation programs.
- If estimated savings are fully realized, the ETO's activities through 2012 will save an amount of annual energy equivalent to about 1.4 years of growth in the Northwest Natural system.
- In the next IRP planning cycle, it may be possible to evaluate ETO energy efficiency programs in the context of a fully integrated resource stack where an optimization model chooses a mix of demand- and supply-side resources.
- Demand response strategies such as seeking out firm customers that can be curtailed during peak periods are severely limited because so many of the company's customers already take service on interruptible rate schedules.
- The company will continue to work with and encourage the ETO to pursue cost effective energy efficiency improvements and clone successful ETO programs for its Washington service area.

III. THE PARTIAL DECOUPLING MECHANISM

In the OPUC docket number UG 143 the company established a partial decoupling mechanism that is also referred to as Distribution Margin Normalization or the Conservation Tariff (see OPUC Order 02-634, dated September 12, 2002). The mechanism partially severs the relationship between volumetric sales levels and the company's earnings level.

As an intended consequence, decoupling removes the near term incentives for load building and load retention by utilities. Each month actual use per customer is compared to a reference level established in a general rate case. When compared to the rate-case normal-weather usage level, the amount of under or over use per customer is determined and is then multiplied times the number of customers and applicable distribution margin per therm. The resulting amounts to be refunded or collected from customers are accumulated to a deferred account to be refunded or collected during the next gas cost tracking amortization period. As a consequence, the effects of customer behavior on earnings is reduced whether brought about by price level changes, conservation programs, appeals for reduced energy use during “energy crises”, added appliances that increase sales levels per customer, or deteriorating or improving economic conditions.

Decoupling eliminates the disincentive to pursue energy efficiency and allows the company to encourage other entities to promote energy efficiency in the most cost-effective manner possible.

The DMN tariff as enhanced by the Weather Adjusted Rate Mechanism (WARM) authorized in the OPUC UG 152 general rate case docket, makes NWN largely indifferent to changes in energy throughput. Under WARM, real time adjustments are made to customers’ bills to reflect the effect of weather on gas use. If the weather during the billing period was colder than normal, customers’ bills are reduced to produce the margin revenue that would apply under normal weather conditions. During a billing period with warmer than normal weather customers’ bills are increased. When both DMN and WARM are taken together, weather and non-weather sources of variation in use per customer are partially compensated for. The term partial compensation applies because only 90 percent of distribution margin is refunded or collected through the decoupling mechanism and approximately 9 percent of customers have opted out of the WARM program. And, whereas the decoupling mechanism applies to both residential and commercial class customers, the WARM mechanism only applies to residential and small commercial customers – thus excluding large commercial customers.

Some observers might suggest that the DMN mechanism appears to have the result of not allowing customers to benefit from their conservation actions. However, it must be remembered that a major component of retail rates is represented by the commodity cost of gas and the cost of purchased capacity. Since these two components of customers’ volumetric rates are not normalized or adjusted, a significant conservation price signal is preserved. Customers still save money by reducing their consumption under decoupling.

In the fall of 2004 NWN launched an independent review of the DMN mechanism. A partial list of questions and issues to be evaluated includes:

- Did DMN remove the relationship between sales and profits?
- Has our corporate culture changed?
- Has our marketing ethos changed from load retention to the promotion of energy efficiency?

- Have we acted to enable success for the Energy Trust of Oregon?
- Did the DMN impact service quality?
- Investigate individual customer bill incidence differences between Revenue per Customer Decoupling and the combination of DMN and WARM.

IV. PUBLIC PURPOSE FUNDING AND THE ENERGY TRUST OF OREGON

The Energy Trust of Oregon is a non-profit organization established to provide energy efficiency services and a renewable energy program to customers of Oregon investor-owned **electric** utilities. According to it's website at www.energytrust. org, its mission *"is to change how Oregonians produce and use energy by investing in efficient technologies and renewable resources that develop new sources of clean energy, help Oregonians lower their electricity bills, stimulate the economy, and protect the environment…"* The Energy Trust is accountable to the Oregon Public Utility Commission.

The Energy Trust has taken on the goal of saving 300 average megawatts of electricity over its ten-year charter period (from March, 2002 through March 2012). Goals for natural gas savings call for 18.7 million therms per year by the end of the same time period.

As discussed earlier, in order to better align company interests with customer interests and to provide earnings protection from the effects of the ETO's Energy Efficiency successes, NW Natural sought and obtained a partial decoupling mechanism in Oregon. In negotiation with the OPUC, the company volunteered to collect a public purpose charge for conservation as a companion to its decoupling proposal. As seen in page CC-1 of the appendix to this chapter, the company's charge covers fewer functional areas than the electric charges coming out of legislation for electric Investor Owned Utilities in Oregon Senate Bill 1149. The company sought to find an external administrator for the funds collected, and the ETO seemed to be a perfect choice. Since the Energy Trust of Oregon had been created to administer electric energy efficiency (for PGE and Pacific Power), it made sense to have them administer investments in gas EE as well.

It is important to note that unlike the electric utilities, NW Natural's cooperation with the Energy Trust is ***voluntary***. For this reason, the company's contracts and relationships with the Energy Trust are sometimes quite different from those between the electric IOUs and the Energy Trust.

SB 1149 required Oregon electric IOUs to collect 3.0% of their gross operating revenues to cover the five functional areas shown in lines 1 through 5 of page CC-1. Beyond this, electric low-income bill payment assistance represents approximately another 0.7 percent for a total of 3.7 percent.

NW Natural developed funding levels for natural gas that are lower than those for electricity. Avoided Cost estimates for gas utilities and electric utilities are quite different with electric avoided costs estimates running above those for gas. Hence, for a given house-tightening conservation measure pay back periods are longer for gas than for electricity. The avoided cost (supply costs avoided when investing in demand reductions) associated with saving electricity is perhaps between 2 and 4 times greater than the avoided cost of saving natural gas with the same conservation measure (the *range* is due to differences in conservation measure load factors).

Ignoring electric funding for Educational Service Districts, New Renewable Energy Sources, and Low-Income Housing Grants that do not apply to natural gas (lines 1, 3 and 5 of page CC-1), we determined that a collection of 0.9 percent from NWN would be comparable to the 2.05 percent collection from electric IOUs for Conservation and Market Transformation and New Low Income Weatherization, when adjusted for the difference in avoided cost. As negotiations with the OPUC proceeded, the amount grew to cover the transfer of existing programs and other costs which the OPUC wanted the Energy Trust to continue but without using the 0.9 percent which was interpreted by the OPUC staff as being dedicated for “new and enhanced” programs. The resulting funding level for conservation amounts to 1.5 percent, and the total amounts to 1.77 percent when bill payment assistance is included.

The company has and continues to work with the Energy Trust to provide a seamless environment for our customers to seek and find assistance with their energy efficiency concerns. A Memorandum of Understanding between NWN and the Energy Trust signed in April 2003 provides the architecture for a unique cooperation between the two entities. Examples include:

- Cooperation to provide a premium web-based energy analysis tool developed by Nexus Energy to NW Natural’s residential customers. Under this arrangement, the Energy Trust provides the product to NW Natural for its incorporation into NW Natural’s website where it enhances the utility’s service to its customers. In return, it serves as a lead generator for the ETO.
- An arrangement whereby the ETO, recognizing NWN’s resources and expertise for equipment lead management and customer communications, forwards all furnace leads to us. In return, NWN refers its frequent inquiries

regarding energy efficiency and conservation to the Energy Trust.

- A cross-linking of NWN's and the ETO's websites to improve traffic to each.
- NWN's provision of occasional media space to the promotion of ETO and its programs.
- A data sharing arrangement whereby, NWN will share customer information necessary for program implementation and evaluation with the ETO. In return, the ETO will share equipment adoption information, useful for system planning and customer safety with NWN.
- Finally, a sharing of staff time between the entities enables both to understand and support each other's business needs. For example, NWN participates on the ETO Conservation Advisory Council and the Energy Trust has provided input to NW Natural's integrated resource planning process. A relationship has developed between NWN, the ETO and its Program Management firms that fosters frequent and effective consultation between the partners to ensure that overall program objectives, important to each, are successfully achieved.

Key Energy Trust staff seem to understand that using natural gas directly makes sense, particularly for water heating. It's clear to them that 50% efficient combustion-turbine-based generation does not represent the best stewardship of natural gas. However, Energy Trust policies prohibit the organization from promoting fuel switching. Discussions among Oregon policy influencers about fuel-switching policy may result in changes that pave the way for the Energy Trust to consider fuel switching in certain applications. Future prices of natural gas and electricity (tied to natural gas prices more and more) will likely heavily influence the future of the policy. For now, the Energy Trust is willing to share its analysis of end-use economics by fuel, when requested by customers. Of course, under the decoupling/conservation tariff the financial benefits of added gas load that increases use per customer flows directly to customers rather than, as in the past, to shareholders.

For a view of Energy Trust programs, visit the Energy Trust website at www.energytrust.org. Click on either "Homes Programs" or "Business Programs" to see a complete and current list of available programs and incentives. You will not observe parity between electric and gas programs for several reasons: (1) There aren't as many gas end uses as electric end uses; (2) Higher avoided costs for electricity make programs that save electricity easier to cost justify; (3) Because the Energy Trust electric programs have over a year's head start on gas programs, some programs intended for development are not yet available. For a publication titled Natural Gas Efficiency and Conservation Measure Resource Assessment for the Residential and Commercial Sectors, prepared for the Energy Trust by Ecotope, Inc., August 2003, go to the following link:

www.energytrust.org/Pages/about/library/reports/GasRptFinal_ SS103103.pdf – The study is specific to NWN's Oregon service area.

The Energy Trust has been granted a period of ten years to accomplish its goals. However, our agreement with the Energy Trust is only for three years. Whether the company will continue its relationship with the Energy Trust beyond that period is dependant upon an independent evaluation of the decoupling/conservation tariff mechanism and the continuation of decoupling beyond its three-year experimental term. Beyond this, a process has recently been initiated by the OPUC to establish performance goals for the ETO in both electric and gas conservation.

For the time being, the company administers public purpose funding for low-income weatherization. Funding levels shown at line 4 of page CC-1 are distributed to Oregon Community Action Planning agencies that, in turn, administer low-income targeted weatherization programs. Guidelines have been modified from past approaches to channel investments in the most cost effective manner with reimbursement levels for allowable measures expressed on a per-square-foot of treated-area basis. Tariffs authorizing this modified approach call for a measurement and evaluation study following the first two years of experience.

V. ENERGY EFFICIENCY STRATEGY IN WASHINGTON

The company runs two kinds of conservation programs in the state of Washington. One is a traditional resource acquisition approach available to residential customers and covers the usual list of house tightening measures such as floor, wall, and ceiling insulation, duct and infiltration sealing. The other program is a market transformation approach to increasing penetration rates for high efficiency gas furnaces (full condensing furnaces with efficiency ratings of 90 percent and higher). The house tightening program currently experiences approximately 50 participants per year and the furnace efficiency program has approximately 350 participants per year.

As the ETO is able to establish new ways of delivering energy efficiency to Oregon residential and commercial customers, we would like to copy their successes into our Washington service area. Of course, if decoupling were approved in Washington the company would not face lost margin issues associated with successful conservation programs. Instead of using the ETO's facilities and staff time, we would simply plan to use their contractors to provide similar conservation services and EE delivery approaches in Washington. EE program cost recovery would be dealt with using deferred accounting with account balances amortized once each year at the same time that other technical adjustments are made to rates to reflect gas cost changes.

The company proposed implementation of Revenue per Customer Decoupling in Washington in the context of its recently settled general rate case. While voluntarily removed by the company for settlement purposes, the rate case settlement anticipates further discussion of decoupling with the WUTC. A decoupling workshop for the Washington Utilities and Transportation Commission is scheduled for September 14, 2004.

VI. LOW-INCOME WEATHERIZATION IN OREGON AND WASHINGTON

The company's public purpose funding mechanism in Oregon provides approximately $1.35 million per year for low-income weatherization programs. The company distributes these funds to Oregon Community Action Planning Agencies (CAPs), that in turn administer conservation programs targeted at low-income residential customers.

With the completion of the company's recent Washington general rate case the company has been authorized to administer low-income weatherization programs in Washington. In Washington, funds distributed to CAPs are recovered through deferring the amounts expended with collections subsequently put into rates as temporary increments through the annual gas cost tracking mechanism. Expected expenditure levels in Washington amount to approximately $0.1 million per year.

Table C-1 summarizes expenditure levels and therm savings expected from these programs as they mature during the next few years. Taking Washington first, the planned, current and mature levels shown assume that planned levels will materialize. This option for CAP agencies has only been in place since July 1, 2004. The interpretation for Oregon is a bit different since the amount of funds collected is not currently tied to activity levels.

Table C-1

Low Income Weatherization
Annual Cost and Savings (in therms)

	Oregon		Washington	
	Cost	Savings	Cost	Savings
Planned Activity Level	$1,350,000	166,490	$104,834	9,984
Current Activity Level	$583,784	63,918	$104,834	9,984
Percent of Planned	43%	38%	100%	100%
Near-Term Activity Level	$875,676	106,200	104,834	9,984
Percent of Planned	65%	64%	100%	100%

In Oregon, CAP agencies have found it challenging to weatherize homes at the pace implied by the funding level. Staffing and finding matching funds from other sources seem to be the limiting factors. The levels of energy savings shown for the mature case assumes that CAP agencies will perform at their hoped for levels in the near future. The company continues to work with CAP agencies to improve their performance. As mentioned in Chapter A, this Plan does not reduce the demand forecast for the effects of low-income weatherization programs.

In Oregon, the company's administrative role was anticipated to be temporary with the function ultimately outsourced to the Energy Trust or another administrative entity. The program has been running since October of 2003. Thus measurement and evaluation of program cost effectiveness performance will not be possible until we have a substantial number of participants and at least a year has passed thereby permitting a before and after period of observation. In the mean time, public purpose funds accumulate in an interest bearing account for future disposition.

VII. OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

A. LOAD MANAGEMENT AND DEMAND RESPONSE

Following the 2000-01 energy crisis, energy planners' attention focused on a group of activities generally known as demand response. Its general purpose is to help manage demand during periods of system stress. To date, because of the severe western

United States disruptions in electric energy markets, virtually the entire emphasis of demand response programs has centered on correcting market failures in electric energy markets. The term encompasses a number of activities including real time pricing, time of use rates, critical-peak pricing, demand buyback, interruptible rates, and direct load controls. To varying degrees, several of these techniques to manage peak demands are used by Northwest Natural.

On the NWN system, customers taking service on interruptible rates represent approximately 42 percent of annual throughput. This includes interruptible sales service, interruptible transportation service and firm on our system transportation service where the transporter, not the company, is responsible for the firmness of upstream pipeline capacity arrangements. Interruptible service is very attractive for large volume customers because of the low distribution margin involved.

The Federal Energy Regulatory Commission pricing policies for interstate pipeline service have implications for the type of load that NW Natural should serve. Straight fixed variable pricing of pipeline capacity means that the company's demand and load management activity should encourage gas use by high load factor customers and discourage low load factor use. As customer classes, residential and commercial customers have a lower load factor than other customer classes (residential, 16 percent; commercial, 15 percent; as shown in Appendix A, page AA-3). Residential customers with the poorest load factors, however, are those who have installed natural gas for the sole purpose of "backing up" other fuels. For example, natural gas acts as a back-up or standby fuel for wood heat, electricity, or other fuels. Commercial establishments using gas solely for freeze protection purposes have the lowest load factor and the highest relative contribution to peak day requirements in this class of service.

With these concerns in mind, NW Natural has modified its main extension policies to more carefully qualify new customers for free main extensions. Residential customers requesting gas service only for space heating are more likely to have to contribute to the construction cost of mains and service lines. Customers requesting gas service for both space and water heating are far less likely be required to make construction cost contributions. Assessment guidelines for both residential and commercial customers seeking gas service use the customer's estimated load factor in customer contribution calculations. Further tariff improvements exclude gas furnaces backing up electric heat pumps from the definition of primary space heat.

B. RATE DESIGN

In general, the company believes that rate design policies should encourage year-round energy efficiency and cause customers to not place excessive demands on the system during severe weather episodes. The company also believes that revenue stability is desirable. Toward these ends, the company's initiatives with respect to the partial decoupling mechanism and the WARM mechanisms in Oregon strike a reasonable balance.

Most parties recognize that the company's cost of performing the distribution function is fixed. Costs are independent of the volume of gas delivered (with the possible exception of the cost of odorant added to natural gas when odor-free gas is delivered from the interstate pipeline system). Fixed distribution system cost per customer is much the same for all customers on a particular rate schedule. For example, while the cost of adding new residential customers varies somewhat from customer to customer, there is not a great deal of variation. With the exception of the incremental cost of upstream capacity (or its substitutes like underground storage), distribution system costs are almost entirely independent of the amount of gas a residential customer consumes on an annual basis. This creates a situation that begs for straight-fixed-variable pricing.

In effect, straight fixed variable pricing could consist of a two-part rate with just a customer charge and a volumetric rate equal to the commodity cost of gas. The result would be complete revenue stability from the company's perspective. Two camps of concern would have problems with this approach. Advocates for low-income groups would suggest that this would result in higher bills for low-income customers. Northwest Natural observes that while there appears to be a positive relationship between natural gas use and income levels, it is not a strong relationship. Energy efficiency advocates would point out that the marginal cost of comfort would be reduced from about 109 cents per therm for Oregon residential customers to a level of about 54 cents per therm (the approximate cost of commodity gas, October 1, 2004 rates). The expectation being that individuals across all income levels would increase their levels of gas use throughout all times of the year with space heating gas use most strongly effected. By not moving to straight fixed variable pricing, our current volumetric rates embody a *de facto* 55 cent per therm carbon tax that customers must face when making thermostat setting choices.

The pros and cons of alternative rate designs with respect to effects on customer behavior and effects on the goals of rationing peaking capacity, minimizing carbon dioxide releases, and improving revenue stability were discussed in Chapter C of the company's 2000 IRP.

The combination of company's partial decoupling and WARM mechanisms in Oregon allow a reasonable compromise between the extremes of collecting fixed system costs primarily through customer charges or collecting fixed costs primarily with volumetric charges. For residential and small commercial customers we have retained the existing approach of recovering the bulk of fixed system costs through volumetric charges. Thus, the marginal cost of comfort is kept high, customer charges are kept relatively low, and revenues are substantially stabilized through the partial decoupling and WARM mechanisms.

Rate redesigns recently completed in both Oregon and Washington have introduced explicit demand charge billing determinants for large volume customers taking service on the new rate schedules 31, 32 and 33 in Oregon; and Rate Schedules 41, 42, and 43 in Washington. As currently structured, customers can choose to pay for capacity at a rate equal to the average cost of purchased upstream capacity or a charge based on their specific peak day requirements. Over time, the company hopes to increase reliance on customer-specific capacity-charge billing determinants and move away from the use of average cost of purchased capacity. The first enabling steps have now been taken.

Beyond this, declining block rates for residential and small commercial customers have now been eliminated in the company's Washington service area. Thus, we have improved the provision of price signals with respect to environmental and global warming concerns, but we have also increased revenue instability in Washington.

With respect to Demand Side Resource planning in Washington, the major remaining step is to establish Revenue Per Customer Decoupling for residential and commercial class customers following the blue print set forth in the company's Initial General Rate Case Testimony and proposed Schedule 220 in the Washington UG 031885 docket (go to: http://www.wutc.wa.gov/rms2.nsf?Open).

CHAPTER D: LINEAR PROGRAMMING AND THE COMPANY'S SUPPLY-SIDE CHOICES

CHAPTER D: LINEAR PROGRAMING AND THE COMPANY'S SUPPLY-SIDE CHOICES

I. OVERVIEW

A. THE APPROACH TO OPTIMALITY

As loads grow across the company's eight service districts, various methods exist for supplying them. The company could purchase additional pipeline capacity, expand storage facilities or put new pipe in the ground to improve the interconnectivity between districts. None of these activities preclude the others, so there are a large number of potential resource combinations that could be adopted to serve new customer needs. The task at hand is to choose the best (in this case, least cost) combination. The method used is called Network Linear Programming.

Network linear programming is an approach to least cost planning that captures the nodal nature of the constraints to getting supplies to demand centers and simultaneously examines a large number of methods of producing a desired outcome (in the present case, meeting customer requirements) in a manner that allows selection of the "optimal" combination of methods. In the current analysis, the characteristics of each kind of supply measure are defined in the model (cost of the resource, amount of gas it can deliver per day and year, the time at which it will become available, etc.). The model is then told that it must meet the requirements presented in each service district for each time period, and a solution is sought. The network linear programming model will then pick the combination of resources that meets requirements at the lowest cost. The operational meaning of lowest cost is to minimize the net present value of future revenue requirements borne by the company's ratepayers.

The development of the Integrated Resource Plan has, in Chapter A, produced a range of probable future load growth forecasts, and in Chapter B, has examined the existing and future supply-side resources that will be available to serve that growth. In Chapter D, analysis determines the combination of supply-side resources and delivery routes from supply to demand, that can best be used to meet anticipated load. Best, in this instance, also means lowest cost, consistent with adequate service quality and reliability standards.

II. KEY FINDINGS

* For this planning cycle, the company does not foresee a near term need for any major investments in pipeline capacity, storage resource or infrastructure projects.

* Recall of pre-built storage resources currently dedicated to the interstate storage service market into core-market service best meets growing peak-day requirements and annual working gas requirements.

* Current interstate pipeline capacity appears to be adequate but opportunities for strategic acquisitions will be evaluated when opportunities present themselves.

* The principal system benefit of underground storage development is the avoidance of more expensive pipeline capacity additions. Storage development and the existing South Mist Pipeline Extension permit direct service to Southwest Portland, flexibility for increased Northwest Pipeline Corporation deliveries north of Molalla to Washington, augmentation of gas flowing south on the NPC system from Molalla to Eugene, and augmentation of gas flowing to the east toward Estacada.

III. EXCLUDING COMMODITY COSTS FROM THE 2004 PLAN'S OPTIMIZATION ANALYSIS

Unique circumstances surrounding the development of the 2004 IRP permit the treatment of commodity gas cost levels as exogenous to the optimization model. The opportunity presents itself because energy efficiency gains are treated exogenously in this Plan. Specifically, this Plan uses estimates of energy efficiency savings developed by the Energy Trust of Oregon as discussed in Chapter C, rather than solving for the optimum mix of demand-side and supply-side resources. This circumstance may not pertain to future plans, so the exclusion of commodity cost variables in this planning cycle does not establish a precedent affecting future plans. Differences in commodity cost, that is departures from the Weighted Average Cost of Gas (WACOG), do make a difference and are dealt with as described below in section B.

A. DEMAND-SIDE RESOURCES

The company's previous IRPs included commodity costs in the linear programming (LP) model to permit the analysis of demand-side resources.

Conservation resources provide benefits by reducing demand for commodity gas and by delaying the need for investments in traditional supply-side capacity related resources. To recognize the benefits of demand-side resources, it was appropriate to model commodity costs, since it was through reducing these costs that a significant portion of demand-side benefits were rendered. The linear programming models used in earlier Plans could choose between alternative conservation programs while recognizing the resulting gas commodity cost savings and the avoidable (delay-able) investment cost of capacity enhancing investments. Technically stated, the level of DSM investments, capacity-enhancing investments, and the level of commodity gas required were simultaneously determined as endogenous variables in the LP model.

Including the cost of commodity gas in a linear programming model presents two computational challenges. The first involves LP model tolerances and run times. Commodity costs represent most of the cost of supplying customer demands over a 20 or 30-year time horizon. Earlier LP model objective function values (net present value of revenue requirements) were very large because they were dominated by the cost of commodity gas in 30 consecutive design winters. Incremental capacity costs and the cost of selected DSM programs were a small fraction of objective function values. In the 2000 Plan, 30-year objective function values varied from $4.7 billion in the base case to $3.9 in the low forecast case, and $8.9 billion in the high externality cost adder case. With commodity cost removed, objective function values are now in the range of $79 to $272 million for 20-year model runs, with the 20-year base case at $134 million. The objective function value for the 30-year base case amounts to $345 million.

Since the variables that are being optimized by the LP model are really capacity costs, including commodity forces an uncomfortable situation wherein the factors being analyzed are only 7.5 percent of the total objective function value. In effect, the linear programming model is focusing it's analytical attention on what is a small part of the total analytical structure. Solution tolerance bounds or the convergence criterion must be set quite tight to focus on the relativity low cost tradeoffs, thus increasing computation time. It is more comfortable, analytically, to have the portion being optimized make up a bit more of the total objective function value. Leaving commodity gas out of the LP model achieves this desirable result.

The second computational challenge involves the determination of the supply cost savings when a first best solution is compared with a second best solution in the company's LP models. This concern was discussed at some length in OPUC Order 00-782 acknowledging the company's 2000 Plan (see Appendix D pages 2 and 3 of the Order). With endogenous commodity costs, running the LP model against a design winter each and every year of the planning horizon overstates gas costs when compared to gas costs resulting under normal weather conditions.

With public purpose funding and the Energy Trust of Oregon administering energy efficiency programs in Oregon, it is no longer necessary for the company to evaluate DSM options in its optimization model. Of course, Energy Trust savings estimates are used to reduce forecast gas demands. We continue to provide avoided cost estimates in Chapter E in the same format as in the past with separate estimates of avoidable capacity and commodity costs. While commodity costs are not included in the LP model specification, commodity cost forecasts are considered in Chapter E and a Base Case forecast is selected. Avoided cost estimates including externality cost adders are also provided in this Plan. With some modification, the ETO will use these estimates for avoided cost screening of their programs, and they will be used by the company to evaluate energy efficiency programs in the state of Washington.

Estimates of ETO energy savings beyond the Trust's current charter that expires in 2012 is complicated by two offsetting factors. Easily acquired conservation may become exhausted, making additional energy-efficiency acquisitions more expensive. By 2013, commodity cost and capacity cost savings estimates escalate, perhaps rendering the new and more expensive echelon of potential ETO activity cost effective.

B. SUPPLY-SIDE RESOURCES

While the *level* of commodity costs does not play a role in optimizing supply-side resource choices in the company's 2004 Plan, *differences* in commodity costs do play a role. For example, one of the Plan's sensitivity cases involves changing the assumed level of summer-winter price differentials from 3 cents per therm to zero cents. The current model specification recognizes the resulting differences in objective function values. As another example, while limited by physical constraints, the option of re-injecting gas into storage during lulls between winter cold spells would recognize the premium paid for spot gas during a cold winter. In both cases, objective function values capture differences in commodity cost by accumulating the number of therms affected multiplied by the price differences in each time period.

The Plan's LP model selects the least cost timing of investments in, or purchases of, pipeline capacity, underground storage development, or bridging resources such as satellite LNG. These choices are independent of the level of commodity costs but not independent of differences in commodity cost.

To the extent that alternative sources of incremental capacity have differing fuel use intensities, in concept, the level of commodity cost could have supply-side resource choice implications. Pipeline deliveries and underground storage involve compressor fuel use, with pipelines using 4 percent of delivered energy on average to move gas from various supply basins, and underground storage requiring an additional 2 percent fuel use factor to move gas into and out off storage. Since pipeline capacity and underground storage tend to be complements rather than substitutes, you cannot have one without the other. Even at extremely high commodity costs, an optimization model will not reject further investments in underground storage simply because of the additional 2 percent fuel use factor. As commodity costs rise, *relative* fuel costs and fuel intensities remain the same.

LNG facilities have much higher fuel use intensities since LNG facilities liquefy natural gas through refrigeration that takes the gas to minus 260 degrees Fahrenheit. Liquefaction fuel use amounts to approximately 18 percent – or, 18 therms are combusted for every 100 therms placed in storage. Fuel use for vaporization amounts to less than 2 percent when the LNG is returned to a gaseous form. Again, even at extremely high commodity costs, satellite LNG facilities would not be rejected by the optimization model when faced with the high cost of commodity gas burned in the refrigeration process.

Even in the highest cost regime of Externality Cost “adders” required by OPUC Order No. 93-695 in Docket UM 424 where an additional 26 cents per therm is attributed to the cost of natural gas, one would not witness supply-side resource choice reversals. The mix and timing of additions to pipeline capacity, underground storage and satellite LNG would remain unchanged.

While the company’s past Plans included commodity cost in its optimization modeling, the intent was not to optimize gas supply portfolios. This is a separate exercise from the “capital budgeting” orientation of gas supply capacity planning in Least Cost Plans. Our approach to gas supply portfolio optimization is discussed in Chapter B (Supply Side Resources). Issues associated with price volatility, long-term versus short-term contracts, hedging strategies, and company policy with respect to derivatives trading is dealt with there.

IV. THE NETWORK LINEAR PROGRAMMING MODEL

Since the development of the simplex algorithm by George Dantzig in 1947, network models have been extensively studied. This can be attributed to the fact that there are numerous applications for network flow models. In addition these models all exhibit an intriguing and elegant structure. This network structure can be exploited in the development of specialized algorithms that produce solutions in one one-hundredth the time and cost required for general algorithms. Furthermore, network geometry (or relationships) can be easily displayed in two-dimensional drawings, greatly simplifying the communication of the model design.

A. NETWORK ENTITIES: NODES AND ARCS

A network is composed of two types of entities -- arcs and *nodes*. Arcs may be viewed as directional means of gas transport and nodes may be interpreted as locations or the connection points of arcs. For IRP modeling, the nodes consist of supply, demand, and flow through or way point nodes. Arcs contain information regarding gate station capacity constraints, storage deliverability and the capacity of connections between nodes in NWN's gas transmission network. While not intuitive, we have modeled gate station and storage resource capacities as connecting arc capacities rather than gate station or storage resource node capacities. Gate stations or city gates are nodes where gas is transferred between the interstate pipeline system and NWN's distribution system.

Nodes: For the IRP model, the supply nodes consist of on system and off system supply locations. On system supply locations are Mist, Gasco, Newport and Recallable Contracts. Off system supply locations include Pipeline Contract Demand, and the Plymouth and Jackson Prairie storage facilities. Each is modeled with a daily deliverability and an annual deliverability. Deliverability is modeled using capacities on the arcs that leave supply nodes. Annual deliverability is modeled using a starting inventory equal to the annual capacity and then tracking use during each time period of the planning year (July through June). See Chapter B for a detailed discussion of existing and potential supply-side resources.

The NWN service districts represent the demand nodes in the network model. See Chapter A for the discussion of demand forecasts. All demand in each district must be met during each time period.

To approximate the supply to demand connections in the NWN gas distribution network, flow-through nodes are added to the model. Flow-through nodes neither consume nor produce and therefore in all cases gas that enters a flow-through node must also exit. This creates additional constraints in the network linear program.

Arcs: Arcs come in several forms for the NLP model: supply connections to the NWN network, gate station connections and general between-node connections used to approximate the NWN gas transmission network. Supply connections allow the modeling of daily deliverability for supply measures. See table D-1 below for specific examples of daily deliverability for on-system and off-system supplies. The Grants Pass Lateral gate stations are represented in the NLP as arcs connected to the NWN network, and specifically, as arcs directed toward the service district each serves.

B. LEAST COST OPTIMIZATION

The least cost aspect of the network linear programming model attempts to minimize an equation of the following form: (cost of supply)

Sum over all years, all periods, all arcs ($c_{ijk} * x_{ijk}$) +
Sum over all years, all resource options ($f_{mk} * y_{mk}$)

where $\mathbf{X_{ijk}}$ is the flow on an arc (e.g. a gate station or storage withdrawal from node *i to node j*) in time period *k* and $c_{\mathbf{ijk}}$ is the price of resource on arc *ij* in period (*k*). An f_{mk} is the cost in period *k* of new resource y built in year *m.* This is called the "objective function." It contains a price and quantity expression for each resource that can be used. There are 20 to 30 years in the analysis with each year broken into 15 periods.

The network cost minimization, however, cannot be accomplished by simply failing to supply gas. Total cost of supply must be minimized subject to the condition that all the company's firm customers' gas requirements are met. Thus, the flow of gas is constrained through Flow Conservation Constraints:
(Σ_i indicates "sum over i")

$\Sigma_i x_{ijk}$ = Supply$_j$ (supply nodes) for each *i* and *k*

$\Sigma_i x_{ijk}$ = Demand$_j$ (demand nodes) for each *i* and *k*

$\Sigma_i x_{ijk}$ = 0 (Flow Through nodes) for each *j* and *k*

where $\boldsymbol{X_{ijk}}$ is the amount (in therms) of gas moving on the arc from node *i* to *j* in period *k*. The equations say that the total delivery of gas in the time period (k) must equal the gas requirements for that time period. In other words, customer requirements must be met. Specifically in each period of time the total supply equals total demand and no therms are used at the flow through nodes. The model contains one equation of the form shown above for each time period in each year of the model analysis, or 450 equations (15 periods times 30 years).

Other constraints (or limitations) are also applied to this cost minimization. Some of the traditional supply resources, for example, are storage facilities. Obviously, storage facilities cannot deliver more gas than they have. Therefore, another set of constraints limits each storage facility's use in each year to the amount of gas that the storage facility can hold. There is one of such equations for each storage facility, for each year of the analysis.

Similarly, city gate gas deliveries are limited by the amount of available pipeline capacity. To get gas from the well-head to the city gate, the services of an interstate pipeline are required. Typically, pipeline capacity is bought on a daily basis. That is, a 200,000 therm purchase of pipeline contract demand (CD) means that the buyer is entitled to 200,000 therms of gas deliveries per day for each day of the year. Other constraints tell the model that it cannot use more pipeline CD than the company has already purchased.

The model proceeds to meet customer requirements from pipeline CD and storage resources in a least-cost manner. Eventually, however, the model will find it does not have enough storage or CD to serve the ever-growing gas requirements. At that point, some kind of capacity expansion is in order.

Expected resource requirements can be met in one of three different ways. The model can buy either more CD, build more storage or build new pipes to meet growing customer needs. When the model chooses CD, for example, it does so by simply using gas from one of the pipeline CD expansions that are specified as being available. However, this triggers a set of pipeline fixed costs that must be paid regardless of how much actual gas is moved under this new contract. These fixed costs, or pipeline demand charges, burden the model with costs from the moment the contract is accepted through to the end of the analysis. In the same way, if a storage expansion facility is used, this use triggers the carrying charges on the investment necessary to build that facility. These, too, are fixed costs that are paid regardless of use levels and for as long as the analysis runs.

The entire model, then, consists of an objective function (which sums up the costs of meeting load) and a large number of constraint equations. The structuring of constraints arranged one below the other is known as an array. The model's appearance is as follows:

Minimize $\Sigma_i \Sigma_j \Sigma_k \, c_{ijk} * x_{ijk} + \Sigma_i \Sigma_j \Sigma_k \, f_{mk} * y_{mk}$ (cost of supply)

–Subject to:

- Flow Conservation Constraints
  - $\Sigma_i \, x_{ijk} = \text{Supply}_j$ (supply nodes) for each *i* and *k*
  - $\Sigma_i \, x_{ijk} = - \text{Demand}_j$ (demand nodes) for each *i* and *k*
  - $\Sigma_i \, x_{ijk} = 0$ (flow Through nodes) for each *j* and *k*

•Minimum/Maximum Flows

$0 <= x_{ijk} <= max_{ijk}$ for each period k

•Side Constraint: Zone MDDO

$\Sigma_i \Sigma_j x_{ijk} <=$ Zone MDDO Maximum (Zones 26 - 08) for each period k

•Mixed Integer Implementation

y_{mk} is 1 when resource option m is chosen Year k

f_{mk} = Resource Investment Cost in Year *k to 20* + O&M for years k to 20
c_{ijk} = Cost per Therm on Arc *i-j* in period *k*

where the task at hand is to solve the system of equations for a set of $\mathbf{X_{ij}}$ (resource use levels) which will minimize total cost while satisfying all of the constraint equations.

Solving this system of equations is tedious. Such solutions have only been possible with the invention of digital computers, and only then when these computers became both very powerful and very inexpensive. The company's model is solved by a software package known as the SAS/OR's PROC LP. This package takes in the model and produces a rather large "dump" of output that needs processing to be usable.

The SAS/OR's PROC LP "engine" solves the network linear programming model using a modified "simplex" method -- a laborious process of basic arithmetic carried out over thousands upon thousands of iterations. The simplex solution gives the optimal gas supply mix for the "continuous model." The continuous model allows all variables to take any continuous, non-negative value. Such a solution is simply the beginning of the process, however, because in the present analysis some of the variables must be forced to take particular values.

When NW Natural buys CD from the pipeline or builds a storage plant, fixed costs are incurred. These costs endure over time and must be paid on a regular (usually annual) basis until either the CD is released, or the construction cost is fully amortized. The company cannot take "just a little bit" of a storage facility. It either is or is not built. The model's coefficient for storage facility carrying costs, then, must take a value of either zero (the facility is not built) or one (the facility is built). The same is true of CD, either the contract is not signed (zero) or it is signed (one). In this case, the zero or one is multiplied times CD demand charges in the objective function. Since these fixed cost variables are restricted to the integer values of zero and one, the analysis is known as "integer programming" rather than linear programming. Indeed, since these integer variables exist side by side in the model with other cost variables that can take continuous values (gas use), the method is more properly known as Mixed Integer Programming. This method has the advantage of allowing the analysis of fixed costs scenarios, but the disadvantage of requiring large amounts of computational effort.

The simplex solution reached by the solver will have assigned continuous values to the fixed cost integers. To get an integer solution, each integer variable needs to be set at (exactly) zero or at (precisely) one. This is done on a variable-by-variable basis, and the resulting change in the objective function noted. This is called “branch and bound” processing. When all of the integer variables have been examined at zero and one values, the optimal combination will be that which yielded the lowest objective function value. Examination of the effect on the objective function of shifting a variable value from zero to one, for example, takes a good deal of computational time. The number of such computations increases at the rate of 2^n where n is the number of integer variables. Given the computation effort involved, integer variables are introduced only where absolutely necessary, and then only sparingly. Solution times can vary from two hours to two days.

After the PROC LP’s engine has solved the branch and bound problem, it presents a listing of the computed values of each of the variables that comprise the optimal solution. In addition, the values of the integer variables are examined to see which year they will be set equal to "one" if in fact they are so set. If an integer is set to one, that year is the year when the resource in question (CD or storage) is activated or "chosen."

The files containing the resource variable names and their values are combined into personal computer spreadsheet programs which sort, sum, label and present the annual deliveries by resource in a form easy to comprehend. These results are summarized at page E-2 of the appendix to this chapter.

V. MODEL INPUTS

The NLP model "dispatches" gas from existing storage and CD supplies to meet load requirements. The requirements represent the gas needs of present and future customers developed on a daily basis. If the model were to consider daily requirements, the resulting matrix would be far too big to solve in a practical manner. Requirements equations alone would number (365*20) or 7,300. The number of constraint equations would multiply in a similar fashion. To make the problem manageable, the year's 365 days are aggregated into 15 "periods." To make such an aggregation meaningful, the days of the year (and their associated requirements) are first sorted in order of coldness, with the coldest day (and it's requirements) first, and the warmest day last.

Each of the first five periods are one day in length, representing the five coldest days of the year. The next five periods are each five days in length, and capture the next coldest 25 days. For the next three periods, a length of 30 days is chosen. The next, or fourteenth, period is 60 days long, and the final period is 185 days in length. This grouping allows careful analysis of the coldest days and weeks of the year (where supply shortages are likely to appear first), and allows coarser treatment of the shoulder and summer months when heating requirements are minimal, and supplies likely to be more than adequate.

A. EXISTING SUPPLY-SIDE RESOURCES

To meet the requirements presented in these 15-period years, the company has a variety of storage and CD options. Existing company resources applied to meet load growth are shown in Table D-1 below:

Table D-1

Supply-Side Resources
Existing Resources

Facility Or Resource	**Annual Capacity Th (000)**	**Daily Deliverability Th (000)**
On System:		
Contract Demand	1,168,161	3,200
Mist Storage	80,000	1,900
Mist Production	10,950	30
Newport Storage	10,000	600
Gasco Storage	6,000	1,200
Off System:		
LS-1 (Plymouth) Storage	4,789	601
SGS-2 Storage	11,203	460
PGE (Includes all buyback capacity)	17,850	450

These resources are currently available to meet present and projected load. The daily deliverability sum of existing resources is 8,441,740 therms. Projected demand amounts to 8,754,000 therms for the 2004-05 heating season (see page AA-4). Consistent with LP modeling results, 400,000 therms per day of storage capacity has been recalled from interstate market service and placed in core market service bringing the Mist Storage total to 2,300,000 therms per day for the 2004-05 heating season.

B. NEW RESOURCES EVALUATED

When peak loads exceed the capability of the system to deliver gas, the NLP model looks for other supply sources to meet those loads. The additional supply-side resources posited as available to meet load growth are shown in Table D-2 below, and summarized in greater detail at page DD-1 of the appendix to this chapter:

Table D-2

Supply-Side Resources
Potential Contract Demand Expansions

	CD Expansion Identification	Daily Capacity Th (000)	Year Avail.	Cost $/Therm /Year
Zone 26	CD Expansion 1	200	10	$31.21
Zone 16	CD Expansion 1	200	10	$36.68
Zone 12	CD Expansion 1	200	10	$42.16
Zone 09	CD Expansion 1	200	10	$47.63
Zone 26	CD Expansion 2	200	12	$36.68
Zone 16	CD Expansion 2	200	12	$31.21
Zone 12	CD Expansion 2	200	12	$42.16
Zone 09	CD Expansion 2	200	12	$47.63
Zone 26	CD Expansion 3	200	14	$36.68
Zone 16	CD Expansion 3	200	14	$31.21
Zone 12	CD Expansion 3	200	14	$42.16
Zone 09	CD Expansion 3	200	14	$47.63

For the analysis of very high growth scenarios, the model was given additional CD expansion options beyond those shown above and priced under the same cost terms show above. In addition to the CD resources, the model was given a number of storage expansion options to meet load growth. These are quantitatively detailed in Table D-3 below. LP model inputs for storage expansions are limited to cost and deliverability attributes. Qualitative characteristics, such as subjective evaluations of technical and broadly defined regulatory risks, are more difficult to represent quantitatively.

Table D-3

Supply-Side Resources
Potential Additional Resources Evaluated *

Storage Facility Identification	Annual Capacity Th (000)	Daily Delivery Th (000)	Year Avail-able	Investment Cost (000)
Mist Recall 1	8,500	500	1	$7,817
Mist Recall 2	8,500	500	2	$7,817
Mist Recall 3	8,500	500	3	$7,817
Mist Recall 4	8,500	500	5	$7,817
Generic Integrated Deliverability A	24,000	850	7	$22,488
Generic Integrated Deliverability B	24,000	850	9	$22,488
Generic Integrated Deliverability C	24,000	850	12	$22,488
Generic Deliverability A	0	500	3	$7,630
Generic Deliverability B	0	500	5	$7,630
Generic Deliverability C	0	500	10	$7,630
Molalla Hub	0	1,000	1	$4,500
Newport Enhancement	0	400	6	$15,000
Brownsville to Eugene	0	50	1	$420
Willamette Valley Feeder 1	0	1,000	10	$17,500
Willamette Valley Feeder 2	0	900	10	$11,270
Willamette Valley Feeder 3	0	700	10	$13,900
Willamette Valley Feeder 4	0	400	10	$24,300
Add Compression to WVF	0	1.3 x above	12	$15,000
Satellite LNG	150	50	1	$2,500

* See page EE-4 for a display of annual cost for these facilities evaluated at alternative load factors.

Three critical elements of storage resources in addition to cost have to be considered: uncertainty surrounding projected on-line dates, development and operational risk, and actions necessary for the preservation of future capacity. Achieving projected on-line dates depends on overcoming several potential regulatory hurdles associated with energy facility siting requirements and air quality concerns, in addition to general land use concerns. Each possible *storage reservoir* has development and operational risks requiring the flexibility to modify plans when critical uncertainties are resolved. Preservation and maximization of the annual storage capacity of underground storage reservoirs requires timely re-injection of gas following the production stage to prevent water intrusion. A brief qualitative description of each prospective supply-side resource follows.

Mist Recalls 1 through 4. As growth in core markets require more of Mist's total storage, Mist storage will be recalled to core service. Mist Recall is presented to the model as lumpy resources of 500,000 therms deliverability and 8,500,000 in annual therm storage. In reality, the Mist will be recalled as needed or just in time.

Expand Molalla Hub. With the completion of the South Mist Pipeline Extension from Mist to Molalla and the installation of a compressor station at Molalla, the injection of Mist gas into the Williams Pipeline (also referred to as Northwest Pipeline Corporation or NPC) at the Molalla gate can take place at roughly 700,000 therms per day. By adding further storage capacity at Mist, and a compressor facility between Mist and Molalla, the company can gain an additional 1,000,000 therms of deliverability into the NPC system at the Molalla gate thus allowing NPC capacity to be utilized elsewhere on the company's system.

Newport Enhancement. Additional feeder capacity from the Newport, Oregon, LNG facility was discussed in Chapter B. It provides no net addition to annual capacity, but permits an additional 400,000 therms of daily deliverability.

Brownsville to Eugene. To access stranded Grants Pass Lateral Zone 8 capacity a Brownsville Willamette River crossing is needed.

Generic Integrated Deliverability A, B and C. These three storage resources are generic versions of known reservoirs that will first be placed in interstate storage service and then brought into core market service as needed. Infrastructure costs are explicitly included as a cost of the storage project. The expectation is that between existing production fields, and those developed in the future by exploration and development, NW Natural will evaluate and acquire storage development options and rights as needed.

Generic Deliverability A, B and C. These three deliverability resources are generic versions of Mist deliverability expansions. They do not add to annual working gas or inventory levels.

Willamette Valley Feeder 1 through 4. To meet demand growth in the southern NW Natural service districts, an additional company built and owned Feeder system competes within the NLP model with CD expansions on NPC system's Grants Pass Lateral. This allows NWN to supply Mist storage gas to service districts down the valley without purchasing CD expansions within operating zones of the Grants Pass Lateral. Certain project segments may require Oregon Energy Facility Siting Council (EFSC) approval and permits.

Add Compression to Willamette Valley Feeder. Once built, there is the potential to add compression to the Willamette Valley Feeder to meet growth in the southern part of NWN's system. This potential resource increases the capacity along the WVF by a factor of 1.3 times the original maximum capacities.

Satellite LNG. Satellite LNG plants are designed to meet peak day and near peak day demand. At a daily deliverability of 50,000 therms per day and an annual deliverability of 150,000 therms, Satellite LNG plants are too small to fulfill any working gas needs over a year. The model evaluated siting Satellite LNG in Salem, Albany and Eugene.

VI. LP MODEL SCENARIOS AND RESULTS

For the base case growth pattern, resources options were chosen as shown in the following table. These results are shown in full on a 11"X17" fan folded page appearing at page EE-2 of the appendix to this chapter. Page EE-2 also reports supply-side resource selection results for the other sensitivity cases considered in this Plan.

Table D-6

Supply-Side Resource Selections
Base Case Scenario (Design Weather, 30-year Planning horizon)

Resource Options	Year Chosen
Valley Feeder – Salem to Albany	28
Valley Feeder – Albany to Eugene	20
Miller_Station_Recallable 1	1
Miller_Station_Recallable 2	2
Miller_Station_Recallable 3	5
Miller_Station_Recallable 4	7
Generic_Integrated_Development_A	8
Generic_Integrated_Development_B	11
Generic_Integrated_Development_C	13
Satelite_LNG_(WVF)-Albany	18

Satelite_LNG_(WVF)-Salem	16
Satelite_LNG_(WVF)-Eugene	14
Zone_26 1 (PDX, Vanc., The Dalles)	15
Zone_26 2 (PDX, Vanc., The Dalles)	17
Zone_26 3	22
Zone_26 4	26
Zone_26 5	28
Zone_16 1 (Salem, Incl. Molalla Gate)	20
Zone_16 2	24
Zone_16 3	29
Total Cost (Net Present Value)	$346,984,195

A. BASE-CASE RESULTS – A QUICK SYNOPSIS

The Network Linear Programming model suggests that recalling, or developing new storage resources, for core-market service is preferred over additional pipeline capacity. The model selects available recalls to core and expansions to Mist storage resources rather than the contract demand expansion opportunities presented to the model. The Base Case forecast presents the model with a resource shortage in year one. In year 16 Contract Demand begins to be purchased to cover the annual resource needs (for Working Gas) for the NWN system. Peak Day coverage becomes a problem in year 14 in Eugene and year 16 in the Salem and Albany Districts. Satellite LNG is the resource selected to cover Peak Day in these locations through Year 20. When in Year 20, CD is purchased at Salem and capacity in Salem is released to Albany, where a portion of the Willamette Valley Feeder has been built to carry gas from Albany to Eugene.

B. SENSITIVITY OF RESULTS TO ALTERNATIVE ASSUMPTIONS

Knowing that resource choices are least cost under a variety of circumstances builds the necessary confidence to plan on and proceed with Base Case resource acquisition patterns. Toward this end, the table at page DD-2 tabulates LP model choices of supply-side resources as well as the objective function values for model runs under a variety of alternative assumptions and parameter estimates. In the table, rows correspond to resource choices and columns show how those choices change (or do not change) in response to a change in one or more model inputs. The following sensitivity cases are examined:

1. Base Case Forecast (20-year)
2. Base Case Forecast (30-year)
3. Higher Demand Growth Forecast
4. Lower Demand Growth Forecast
5. 2000 IRP Demand (use per customer at 2000 IRP levels)
6. Higher Cost for Grants Pass Lateral ($0.005 per therm at 100% load factor)
7. Higher Cost for Grants Pass Lateral ($0.03 per therm at 100% load factor)
8. Willamette Valley Feeder Cost at 0.75 times Base Case Cost
9. Willamette Valley Feeder Cost at 1.25 times Base Case Cost
10. Willamette Valley Feeder Option Excluded
11. Zero Summer-Winter Gas Price Differential instead of $0.03 per therm in Base Case
12. Extremely High WVF Cost at 2.0 Times Base Case Cost
13. Shortfall Gas Priced at $10.00 per therm
14. Shortfall Gas Priced at $25.00 per therm
15. Shortfall Gas Priced at $7.60 per therm
16. Industrial Firm Transportation Volumes Included (sales volumes only in base case)
17. Use 2000 IRP Design Winter Concept (includes 1978-79 winter weather)
18. Energy Trust of Oregon Remains Active After 2012

As presented on page DD-2, sensitivity outcomes contain no surprises. Resources selected and their dates of selection are the same during the first 20 years in both the 20-year and 30-year base cases—no resource choice reversals are experienced because of using the shorter 20-year time horizon[1]. Higher growth accelerates resource additions and lower growth delays additions.

Perhaps sensitivity scenario 5 is the most interesting. Here we return use per customer levels to the levels embodied in the 2000 IRP. This requires a pattern of resource selections that exhaust integrated storage resources by the 7th year of the Plan. All segments of the Willamette Valley Feeder are chosen in the first year. Additional pipeline capacity is chosen in the 10th and subsequent years in the southern part of the NW Natural system (the 2000 IRP forecast embodied higher use per customer levels in upper Willamette Valley districts, particularly in Eugene).

Both the Willamette Valley Feeder and Grants Pass Lateral choices are invariant with respect to alternative assumptions regarding their cost. Low cost assumptions for “shortfall gas” have a negligible effect on resource selection dates. Capacity cost savings associated with the extension of the Energy Trust of Oregon’s charter beyond 2012 shifts later-year on-line dates one year further into the future.

C. UNCERTAINTY CONSIDERATIONS

Despite the results of the LP model, which indicate a strong economic preference for storage, potential developments in the natural gas industry require some consideration.

Uncertainty with regard to whether LDCs will continue to perform a merchant function with respect to its firm sales customers has been reduced -- largely as the result of perceived failures in deregulating the energy supply function for electric utilities. Consequently, this has diminished the prospect of an investment in storage becoming unnecessary or uneconomic and thereby stranded if NW Natural's core customers become transportation customers. To date there has been little interest expressed by either customers or marketers for transportation services to this market segment, but this may occur in the future.

NW Natural plans to continue pre-development of underground storage facilities for sales into the interstate market for storage services. When recalled into core-market service, core customers benefit from the company having a stockpile of proven and partially depreciated resources that can be placed in service on a "just in time" and "just enough" basis. As expectations regarding levels of core-market gas use change, recall schedules are adjusted accordingly. In this manner, the interstate storage market provides a hedge against forecast uncertainty in the company's core market.

The recall of pre-developed storage facilities to core-market service is needed in the Plan's first heating season of 2004-05. In the LP model, recall is cast as discrete storage developments providing 500,000 and 850,000 therms per day of peak capacity. Actual "just-in-time" recall patterns involve amounts of capacity that just meet the next year's expected need for capacity in infinitely variable amounts. As a practical matter, to present smaller storage choice "lumps" to the LP dramatically increases the number of integers in the mixed integer model specification, and greatly increases run times for each solution.

Appendix pages DD-3 through DD-5 provide a summary of implicit future deficits by comparing forecast peak day requirements to existing supply-side resources. The tables are designed to highlight the deficit that would exist if no new supply-side resources were acquired. Both the total deficits and incremental deficits are shown for design peak day and design winter scenarios with the design peak day shown an "as dispatched" as well as a "existing resources at full capacity" basis.

The existence of a viable interstate market for storage services demonstrates that storage resources are unlikely to become stranded and without economic value. The company's firm sales customers will require service under peak conditions regardless of who supplies the commodity gas. The IRP indicates that under peak weather conditions, interstate pipeline capacity into NW Natural's market area is insufficient to serve the peak needs of these customers. Storage is the most cost-effective way of serving peak loads. NW Natural cannot control when and how retail transportation may come about, but it can try to assure that resource decisions are the most economic choices. If economic conditions are as they have been discussed in this Plan, then storage resources are an economic choice that will have market value regardless of who builds, owns, or uses the storage, and regardless of who supplies the gas commodity to NW Natural's customers.

If it appears that retail transportation may affect the economic viability of storage in the future, then NW Natural will make the appropriate adjustments in future IRPs. The ability to change course from plan to plan was envisioned by both the OPUC and WUTC in adopting the multi-year IRP cycle, and NW Natural will use this opportunity to continue to monitor important developments in the industry.

D. COST OF CURTAILMENT AND THE VALUE OF RELIABILITY

An ongoing consideration in the company's least cost planning is the evaluation of the relative costs and benefits of service curtailment to the various customer classes. In general, the benefits of service curtailment take the form of delaying capital investments in pipeline and gas storage facilities. Costs of curtailment include utility costs incurred in the re-establishment of gas service after a loss of pressure in distribution mains.[2] The more significant costs of curtailment stem from disruptions to commerce and individual lifestyles when unanticipated service outages are experienced. These costs can range from the merely inconvenient, to loss of inventory and property damage.

LP models in the company's current and past Plan's include a variable called "shortfall gas." Shortfall gas is introduced to avoid infeasible solutions when inadequate conventional resources are available. Some might interpret shortfall gas as the value of reliability or cost of firm curtailment with each therm of un-served load valued at the shortfall gas price. This interpretation must be approached with caution. The cost of curtailment, or the value of reliability is closely related to how customers value continuity of service. Shortfall gas pricing has nothing to do with such valuations, nor has NW Natural made any empirical determinations of customer attitudes toward curtailment and the value of reliability.

Where the NLP model has an appetite for shortfall purchases (or, implicit firm curtailment) one can argue that the least cost solution might be to delay implementing a supply resource, engaging in curtailment and paying the affected customers an amount per therm equal to the shortfall price. For example, were shortfall gas valued at $10 per therm, and were the model to chose this resource in lieu of bringing new storage or pipeline capacity on line, the model would have indicated that the least cost solution is firm curtailment and a payment of $10 per therm to customers who were curtailed (approximately $100 per day for residential customers). What the model fails to tell us is the extent to which customers would be indifferent between continued service and curtailment when presented with the $10 option. Undoubtedly, the option would very likely occur on the coldest days of the year. To assess the value of reliability, one must know the degree to which customers value continuity of service. This remains an imponderable[3].

It must be borne in mind, further, that these LP shortfall gas or spot purchase results are entirely a byproduct of introducing ”lumpy” capacity choices. If capacity were available in infinitely divisible increments, spot purchases would not take place, even if “spot gas” were priced at $2.00 per therm. Because of “lumpiness,” the 2004 Plan uses a shortfall gas price of $100 per therm in order to ensure capacity resources are on line with adequate time to avoid firm curtailment. However, even at this cost, the LP model might occasionally shift a capacity addition one-year into the future when the firm curtailment resulting in the previous year was very small.

END NOTES

1. The notations consist of year selected, not selected or not available. Some resources were made unavailable in time periods where it is known that they would never be chosen in order to reduce computation time.

2. Utility costs associated with loss of pressure in the gas distribution system are well understood. NW Natural has not calculated costs per therm of unserved load associated with periodic gas outages. Costs primarily involve purging air that may have intruded the distribution system, appliance inspections and relights. These costs are almost entirely payroll related due to overtime hours. Additional elements of utility "cost" might include consideration of lost revenues and, more importantly, the general loss of goodwill when firm customers face forced outages.

3. NW Natural has spent the last nine-years searching academic and trade journals for published research on the value of reliability for gas distribution companies. Electronic searches of the Journal of Economic Literature produce no gas industry "hits" on phrases such as reliability, value of reliability, curtailment, cost of curtailment, outage cost, etc. Such studies are found for electricity and water distribution companies, but not gas LDCs. Consultation with C. K. Woo, a prolific author in this area, confirms the absence of value of reliability studies for gas LDCs.

   As a research design proposition, one would have to observe customer behavior over time in an environment presenting choices for degrees of firmness of service and an environment with frequent instances of curtailment orders. This environment existed on NW Natural's system during the 1970s. The necessary database for empirical research does not currently exist in any form accessible to NW Natural.

CHAPTER E: AVOIDED COST DETERMINATION

CHAPTER E: AVOIDED COST DETERMINATION

I. OVERVIEW

NW Natural's avoided cost estimates represent changes in gas supply costs that result from changes in load served. For example, if conservation were to reduce customer gas requirements, the company could shed, or "avoid" certain transmission and gas supply costs. Likewise, serving additional load causes gas supply and infrastructure cost increases. Future customer and load growth, therefore, presumes increased cost and resource usage.

A key question in integrated resource planning is which mix of supply- and demand-side resources will result in serving customer energy needs at the lowest overall cost. Determining the appropriate mix of resources involves finding a pattern for adding alternative supply-side resources over time[1]. With the aid of a linear programming model, resources are selected to meet growing requirements in a cost-minimizing manner.[2] Armed with the knowledge of what resources would be chosen and when, avoided cost computations can be developed.

II. PRINCIPAL FINDINGS

* Due to substantial increases in the price of natural gas since the publication of our 2000 Plan, avoided cost estimates associated with commodity gas acquisition have risen substantially in this Plan.

* With the South Mist Pipeline Extension (SMPE) now complete, near and medium term capacity enhancing investments are relatively low cost. This leads to a reduction in avoided cost estimates for demand-side measures with short life times (20-years of less), when this Plan's estimates are compared to the 2000 Plan.

* For demand-side measures with longer life times (30–years) capacity related avoided cost estimates are higher than in the 2000 Plan due to positing fewer potential underground storage resources in total and the recognition of higher incremental costs for new pipeline capacity resources.

III. METHODOLOGY

The company's avoided cost method focuses on the cost impact of small changes in load. With load growth, resources must be added from time to time to serve these new requirements. The IRP has, as one of its functions, the determination of the least cost means of serving this growth. At any point in time, there will be a "last resource added", or "incremental facility". When load is increased by a small amount, this incremental resource is the one that serves the increase. It is the cost presented by the incremental resource that defines the cost of meeting load increments. The cost of incremental supply-side resources is also the cost that can be avoided when load decreases. Avoided cost, thus, is the cost of serving small load increments (or the cost avoided by load decreases) as defined by the current incremental gas supply resource in each time period.

Computing these costs requires a forecast of probable load growth, a forecast of future trends in commodity gas costs, and a menu of capacity-augmenting investments or purchases that are optimal for meeting those load requirements.

The company has generated a range of load growth forecasts, covering Low, Medium and High growth rate scenarios. The methods used to create these forecasts are presented in Chapter A. The company has adopted the medium load growth forecast as its Base Case, and the medium forecast underlies avoided cost estimates.

IV. AVOIDABLE CAPACITY RESOURCES

To meet these growing loads, the company can draw upon storage or pipeline capacity. Increased capacity on Northwest Pipeline Corporation (NPC), the company's primary supplier, will require that NPC make physical investments to expand peak delivery capability into the various NWN market areas. The pricing of the pipeline capacity additions is sensitive to the point of delivery. Since NPC would need to build more additional pipe to add to deliveries at, say, Eugene than it would at Portland, the rate for incremental pipeline capacity is greater at the southern end of the system than it is at Portland at the north.

New storage facilities that provide significant amounts of annual deliverability must, of necessity, be underground storage. The other major storage option, LNG storage, presents serious siting difficulties for facilities with annual inventory levels above 70,000 gallons, and is consequently too costly to build. The choice of underground storage is limited to available underground reservoirs. The IRP has assumed 6 possible storage related projects during the planning period. These underground storage projects involve both expansions of known storage pools (Generic Integrated Development A, B and C), and increases in deliverability for existing pools (Generic Deliverability Only A, B and C). The daily capacities generated by the first three expansions are assumed to be 850,000 therms per day and 24,000,000 therms annually. The 3 Generic Deliverability Only projects contribute 500,000 therms a day of increased delivery, but do not increase the annual therms available.

An additional supply-side source for the avoided cost analysis is Satellite LNG. This concept involves portable LNG tanks that can deliver 50,000 therms a day for 3 days. These could be placed at strategic points on the system to provide needed local capacity on peak load days.

As an alternative to purchased pipeline capacity, the company has included the option of building enhanced transmission capacity between the Portland district and Eugene. These additions involve a 16 inch pipeline between Portland (actually a location near the midpoint of the SMPE) and McMinnville, a 16 inch pipeline between McMinnville and Salem, a 12 in pipeline between Salem and Albany and a 12 inch pipeline between Albany and Eugene. Finally, the company has included enhanced deliverability between the company's LNG facility at Newport and the company's Willamette Valley service area. This would bring an additional 400,000 therms a day into McMinnville, but would add nothing to annual deliveries.

V. AVOIDABLE GAS COMMODITY COSTS

Commodity costs have been divided into four categories: (1) Weighted Average Cost of Gas (WACOG); (2) Winter Supply; (3) Annual Supply, and; (4) Blended Supply.

The company has considered several sources of long-term gas cost forecasts. Page EE-1 contains a chart that compares some of the principal forecasts and relates them to the company's current WACOG as of October 1, 2004, that is shown as a short red horizontal line at the level of $5.25 per million Btus in the 2004-05 time period. While somewhat unrelated to prices in the Pacific Northwest, a recent New York Mercantile Exchange "strip" of futures prices for October deliveries is shown using a red square symbol. The 2004 U.S. Energy Information Administration (EIA) forecast appears as a blue diamond and falls far below current prices in near term years. Finally, a recent array of five Northwest Power and Conservation Council (NPCC) forecast trajectories are displayed. Of the five NPCC forecasts, the company has chosen the medium-high case as the driver for its base case commodity cost forecasts. Note that after the year 2014 the EIA and NPCC medium-high forecasts track fairly close to each other.

For purposes of assessing the cost of serving anticipated load growth over a 30-year horizon, the company's current WACOG is carried forward by the NPCC Medium High gas cost forecast. The WACOG is the best representation of the annual average cost of gas used to serve the normal mix of long-term incremental customer loads.

When assessing DSM resources, the annual WACOG is not the best choice of commodity cost concepts. In examining the avoided commodity cost for a therm of seasonal load, for example, the relevant avoided gas cost is best represented by *winter* season gas contract prices. The various DSM related commodity costs are properly captured by a mixture of winter season and *annual* contract prices; the particular mix depending on the kind of DSM contemplated. 100 percent load factor, water heating type load is best represented by a *blended* cost of gas that averages the seasonal or winter contract prices in winter months, and the annual contracts in the summer months. The result is a figure fairly representative of the average commodity savings for a therm of load reduction per day throughout the year.

The resources summarized above allow additional load to be served from resource decisions such as the purchase of pipeline CD or construction of additional storage facilities. Should CD or storage be chosen as a supply source, gas will need to be delivered to meet customer requirements. This gas is priced at one of three price levels, Annual Contract Price, Winter Contract Price and Blended Gas Price. The annual contract price represents the average of actual base loaded contract gas prices the company entered into for the 2004-05 heating season.

NW Natural's gas price forecast escalates at the rate implicit in the NPCC gas cost forecast for deliveries at Sumas, BC. This forecast was adjusted or "offset" by an amount equal to the difference between the 2004 NPCC gas price forecast and the company's actual, computed 2004 WACOG. The same approach has been used in all previous plans under the assumption that the actual price paid by the company for commodity gas in say 2004 is a better representation of the company's situation than the 2004 regional price given by the NPCC forecast for that same year. NPCC forecasts of price movements were then applied to the 2004 company WACOG as a starting price to determine the actual string of forecast WACOG prices. Similarly, the NPCC pattern was also applied to the company's actual Winter and Annual gas prices for 2004 in order to develop a string of forecast Winter and Annual prices based on the NPCC forecast price movements.

Table E-4

Commodity Gas Costs
(¢/Therm)

Year	Annual Contract	Winter Contracts	Blended Contracts	WACOG Costs
1	47.13	65.19	54.03	53.01
2	51.16	69.21	58.05	57.04
3	47.78	65.84	54.68	53.66
4	44.59	62.65	51.49	50.48
5	41.58	59.64	48.48	47.47
6	38.74	56.80	45.64	44.63
7	36.06	54.12	42.96	41.94
8	35.65	53.71	42.55	41.53
9	35.24	53.30	42.14	41.13
10	34.84	52.90	41.74	40.72
11	34.44	52.50	41.34	40.33
12	34.05	52.11	40.94	39.93
13	34.15	52.21	41.04	40.03
14	34.25	52.31	41.14	40.13
15	34.35	52.41	41.24	40.23
16	34.45	52.51	41.35	40.33
17	34.55	52.61	41.45	40.43
18	34.85	52.91	41.74	40.73
19	35.15	53.21	42.04	41.03
20	35.45	53.51	42.35	41.33
21	35.75	53.81	42.65	41.64
22	36.06	54.12	42.96	41.94
23	36.36	54.42	43.26	42.24
24	36.66	54.72	43.56	42.54
25	36.96	55.02	43.86	42.84
26	37.26	55.32	44.16	43.14
27	37.56	55.62	44.46	43.44
28	37.86	55.92	44.76	43.74
29	38.16	56.22	45.06	44.04
30	38.46	56.52	45.36	44.34

VI. AVOIDED COST DETERMINATIONS

30-year cost projections for the Base Case load forecast are shown in Appendix E, pages EE-2 through EE-4. Resource cost and timing follows from pages DD-1 and DD-2 (column 2) of Chapter D. Page EE-2 shows incremental deliverability (capacity) for each period, capital carrying cost, operating expense, and the resulting total capacity cost at a 100 percent load factor. In page EE-2, commodity costs are shown at WACOG levels (see table E4, above). Total capacity and commodity costs are summarized for selected DSM measure lives on both a net present value (current lump sum) payment and a levelized (equal annual) payment basis. This is the format formerly used for DSM tariff purposes and includes the so-called 10% conservation credit required in Oregon for residential DSM evaluations. The avoided cost calculation uses a capital carrying charge rate of 9.5 percent and a real, after tax discount rate of 4.12 percent. Financial assumptions are summarized at page EE-5.

Page EE-3 shows similar information in a more useful format and in greater detail covering avoided cost estimates for DSM measure lives from 1 to 30 years. Avoided cost estimates for each year are summarized in the “100% LF” column (column (d)) of page EE-3 where estimates are expressed as dollars per therm at a 100 percent load factor. In the early years of the 30-year planning horizon avoided capacity cost estimates are quite low and then rise quickly once the underground storage options presented to the LP model are exhausted. Costs stay below $0.01 per therm until year 14 and move above $0.10 per therm in year 22.

Appendix page EE-4 provides a comparison of supply-side resource costs with annual costs expressed at 3 different load factor levels. Interestingly, an examination of page EE-4 reveals that the development of reservoirs currently considered marginal candidates for underground storage may be worth further investigation. The difference in the cost of meeting future gas requirements with new pipeline capacity versus combinations of storage reservoirs and new capacity on the Willamette Valley Feeder is dramatic. Using Base Case cost assumptions, the storage and Willamette Valley Feeder combination appears to cost 1/4th to 1/3rd as much as new pipeline capacity on the Grants Pass Lateral.

For example, looking at the “100 % L.F. Cost/therm” in column (g) of page EE-4 note that the sum of costs associated with Generic Integrated Development A, B and C at line 11 and the entire Willamette Valley Feeder project at line 7 amounts to $0.02491 ($0.0143 + $0.00748). The lowest cost Grants Pass lateral segment costs $0.08550 on a 100 percent load factor basis – approximately 3.4 times as much. When unscheduled storage and WVF capacity are bundled and compared to the cost of Grants Pass lateral deliveries to points south of Portland, the multiple increases. When these alternatives are compared on an "Annual Cost of Peak Day Therm" basis, in column (h), a similar degree of cost advantage is shown for unscheduled storage resources that were not explicitly included in this Plan.

A Multi-Year Action Plan task calling for more refined cost estimates for speculative underground storage reservoirs seems called for. Development of an inventory of marginal storage reservoirs should be pursued during the next planning cycle. In view of the approximately 40 known reservoirs mentioned in Chapter B, further savings might be achieved thus reducing the company's avoided cost estimates for capacity the later years of this Plan's time horizon.

A. AVOIDED COST AND LOAD TYPES

While avoided cost refers to the reduction in gas costs associated with a decrease in load, the costs avoided depend on the type of load involved. Seasonal loads have different avoided costs than evenly distributed annual loads. The difference can be shown with a few properly chosen examples.

Seasonal loads are typically heating loads. An extreme example would be a customer who uses gas only on the coldest day of the year, with no other consumption. It is useful to compute the avoided cost the company would experience if just one therm of this customer's load were eliminated. The computation involves breaking avoided cost into its two component parts: capacity and commodity costs.

The capacity cost avoided is determined by the number of peak day therms of eliminated load. If a single, peak day therm is eliminated, then the avoided capacity cost is the annual cost of one therm of peak capacity. If we assume, just as an example, that capacity costs $0.75 per therm per month, then the capacity costs avoided are $9.00 per year ($0.75 times 12). Commodity costs equal the cost of a therm of peak day gas, at, say, $0.50/therm. The total avoided cost, then, is $9.50 ($9.00+$0.50).

On the other hand, if one avoids using a therm of gas a day every day of the year (load factor of 1, or 100 percent), the avoided capacity cost would still total $9.00.[3] The avoided commodity cost equals the cost of 365 therms of natural gas purchased one therm per day throughout the year at the various daily commodity prices. The cost of gas purchased regularly throughout the year is nicely represented by the weighted average cost of flowing gas.[4] If this price is $0.50 then total avoided commodity cost equals $182.50 (365*$0.50); total avoided cost is $191.50; and avoided cost per therm of load reduction equals $0.525 ($191.50/365).

Some loads, such as water heating, closely approximate the “equal therm per day, load factor of one” pattern. Most loads fall somewhere between the load factor extremes of zero and one. In order to compute the per-therm avoided cost for loads with different annual patterns, we need to understand how the "shape" of avoided loads affects avoided cost. As seen in these examples, a seasonal load presents a higher per-therm avoided cost than the year-round, water heating-type load. In general, the lower the load factor, the higher the per therm avoided cost.[5]

B. CONSERVATION LOAD FACTOR

The impact of conservation is to reduce load. The reduction experienced depends on the type of demand-side measure being applied. One measure is the Conservation Load Factor (CLF).

The CLF equals the average reduction (per unit of time) in load divided by the peak reduction in load (per same unit of time). For example, when a water heater is removed, load will decrease by about 0.66 therms on a peak day, and by 0.66 therms on the average day. The conservation load factor here is equal to one. For a space heating load, on the other hand, peak day load might fall by 9.7 therms, and annual load by 602 therms. The average load reduction is (602/365) or 1.65 therms per day. The CLF, then, equals 1.65/9.7 or 0.17. The CLF computes avoided cost for various load types.

The per-therm avoided capacity cost of a particular conservation measure is found by dividing the per-therm capacity cost by the CLF of the particular measure involved. For example, since water heater conservation has a CLF of 1, the avoided capacity cost per therm would equal $0.0246 ((($0.75*12)/365)/1). Space heating, on the other hand, would have an avoided capacity cost of $0.145 per therm ((($0.75*12)/365)/0.1628). For other loads, avoided capacity would equal per therm capacity costs divided by the respective CLF.

Avoided commodity costs also vary with the pattern of the avoided load. A winter-only avoided load causes higher-priced, seasonal gas contracts to be reduced. A water heating load causes a constant reduction in gas purchases each day of the year, and affects a broad range of gas purchase contract volumes. For such a load, the weighted average cost of flowing gas is a good measure of average avoided commodity costs. The commodity costs avoided with various other DSM measures depends on the particular load shapes and commodity purchase avoidance options that each measure presents.

C. AVOIDED COST SUMMARY CHART

Table EE-3 of the Appendix provides convenient and flexible summary of avoided cost estimates under base case assumptions and outcomes. Cost estimates in the table are used to determine cost-effectiveness limits for measures of various life spans and seasonal patterns of gas use. For example, a 20-year DSM resource providing year-round savings at 100 percent load factor would be valued at $6.39202 in net present value terms (combining $0.22552 in capacity savings with $6.1665 in blended commodity savings). Alternatively, a 25-year lived space heating measure would be valued at $0.7242 in levelized terms [combining $0.1575 in capacity costs savings ($0.02516/0.16) with $0.5667 in winter commodity cost savings].

VII. ENVIRONMENTAL COSTS AND EXTERNALITIES

The OPUC's Order No. 93-695 in Docket UM 424 (Development of Guidelines for Treatment of External Environmental Costs) establishes guidelines for the treatment of environmental costs that are to be followed by energy utilities in evaluating demand- and supply-side energy choices.

Unlike electric utilities, a gas utility's supply-side resource choices are largely independent of environmental cost issues.[6] NW Natural does not have the ability to choose between "dirty" coal-fired generation and "clean" wind energy sources. The only available supply-side energy resource for NW Natural is natural gas.[7] At present, the only supply-side implication of environmental externalities is that some methods of natural gas storage require the combustion of the gas. An LNG facility, such as Newport, burns one therm of gas to liquefy five therms. Underground storage, such as Mist, uses one therm of gas to compress 100 therms of gas into storage. Recognizing the environmental externality costs associated with an additional therm of storage versus contract demand is not likely to make an appreciable difference in supply-side resource selection.

Environmental externality costs do make a difference, however, in the comparison between supply-side and demand-side resources. To facilitate such comparisons, Table D-5 presents the "adders" the company recommends be applied to avoided supply-side costs in order to make demand-side versus supply-side resource selections more meaningful. Table D-6 applies these "adders" to the three commodity cost categories.

Table E-5

Natural Gas Environmental Externality Adders
OPUC Order No. 93-695

Compound	Emissions in Lbs./MMBtu	Damage Cost In $/Lb.	Externality Adder $/Therm
NOX $2000/ton	0.11	$1.00	$0.011
CO_2 $10/ton	118	$0.005	$0.059
Total			$0.070
Cost Option 2			
NOX $2000/ton	0.11	$1.00	$0.011
CO_2 $25/ton	118	$0.0125	$0.148
Total			$0.159
Cost Option 3			
NOX $2000/ton	0.11	$1.00	$0.011
CO_2 $40/ton	118	$0.02	$0.236
Total			$0.247
Cost Option 4			
NOX $5000/ton	0.11	$2.50	$0.0275
CO_2 $10/ton	118	$0.005	$0.059
Total			$0.0865
Cost Option 5			
NOX $5000/ton	0.11	$2.50	$0.0275
CO_2 $25/ton	118	$0.0125	$0.148
Total			$0.1755
Cost Option 6			
NOX $5000/ton	0.11	$2.50	$0.0275
CO_2 $40/ton	118	$0.02	$0.236
Total			$0.2635

Table E-6

Summary of Externality Adders
Applied to Commodity Costs

Options	Adder $/Therm	WACOG Commodity W/Adder	Seasonal Contracts W/Adder	Annual Contracts W/Adder	Blended Contracts W/Adder
COST #1	$0.07000	$0.60014	$0.72189	$0.54131	$0.61027
COST #2	$0.15900	$0.68914	$0.81089	$0.63031	$0.69927
COST #3	$0.24700	$0.77714	$0.89889	$0.71831	$0.78727
COST #4	$0.08650	$0.61664	$0.73839	$0.55781	$0.62677
COST #5	$0.17550	$0.70564	$0.82739	$0.64681	$0.71577
COST #6	$0.26350	$0.79364	$0.91539	$0.73481	$0.80377

VIII. FINANCIAL ASSUMPTIONS

The Linear Programming model can evaluate resources of different life spans by applying capital carrying charges to the cost of the resource. Carrying charges can vary from 9.50 percent for 30-year lived assets, to approximately 20 percent for assets with an economic life of seven years. What the LP model sees is a real-economic annual-rental rate for the services of assets chosen by the model. In this Plan, all supply-side resources are treated as though they have 30-year life spans.

Development of the real after-tax discount rate (4.12 percent) used in the LP model and in the development of avoided cost estimates is shown at page EE-3 of Appendix E. Here, the financial assumptions used in the development of capital carrying charge rates applied to resources of various life spans is also detailed, with a 30-year asset used as an example.

END NOTES

1 As explained in Chapter D, demand side resources are not explicitly modeled in this Plan.

2 The company's specific optimization procedures are described in Chapter D of this document. Therefore, no explanation is presented here.

3 Load factor is defined as average load (per unit time) divided by peak load (per same unit time). NW Natural uses daily load factors.

4 Technically, a utility will avoid (or reduce) usage of the highest cost gas available at any given time. Because the avoided cost computation is a long-term (30-year) analysis, the average price of the various annual and seasonal contracts undertaken is a better representation of long-term annual and peak gas purchase performance. A single current highest-price contract tells more about the bargainer's physical or mental well-being on the key negotiation day than it does about long-term gas market prices.

5 In these examples, both loads equaled one therm on peak, and caused $9.00 of annual capacity costs. The high load factor, however, presented 365 annual therms over which to spread the capacity cost. The seasonal load presented only one annual therm. Consequently, high load factor means lower per therm avoided costs.

6 Natural gas has generally been regarded as an environmentally benign fuel that releases fewer harmful agents than many alternative energy choices. While superior to its fossil fuel competitors, natural gas is not environmentally benign. The primary sources of environmental damage resulting from the use of natural gas are direct damages caused by exploration, production and transmission activities; and methane and carbon dioxide emissions. In the process of gas distribution, relatively small amounts of methane are released to the atmosphere through construction and reconstruction activities. Operating practices that reduce methane releases are worthy of further examination by NW Natural's distribution operators. Other methane emissions occur as the result of corrosion, soil shifts, and construction activities by parties other than NW Natural. The mere passage of time causes the distribution system to develop leaks.

Because of public safety concerns, extraordinary efforts are made to find and repair leaks in gas mains and service lines. Company leakage and grading activities have been strongly supported by both the OPUC and WUTC. NW Natural's current efforts to control leaks probably exceed those that would be suggested if these activities were to be assessed in terms of greenhouse gas mitigation benefits alone.

Within natural gas accounting conventions, there is a category for "unaccounted for gas". This is the difference between metered receipts at the pipeline citygate stations and metered deliveries to end users. Over time, annual unaccounted for gas can vary between 0.5% and 2.0% of total throughput. Actual leakage is a small component of unaccounted for gas; most of it is measurement error and occasional instances of theft by customers.

Over the past three decades, concern over environmentally harmful activities has increased. Much of the damage previously done by natural gas production and transmission activity has been eliminated. The cost of these mitigating activities is included in current commodity gas prices and pipeline transmission tariffs. It is probable that residual damages will be subject to future mitigation, and that these costs will be included in future gas charges. For the present, however, the cost of gas and gas transmission already includes the costs of those mitigation activities that are necessary.

The use of natural gas contributes to increased concentrations of two greenhouse gases: methane and carbon dioxide (CO_2). A molecule of methane is currently thought to contribute from five to twenty times as much to the potential for global warming as a molecule of CO_2. At issue, then, is the amount of methane that might be released into the atmosphere as a result of natural gas distribution and use. Gas appliances can emit small amounts of methane both prior to and after ignition. Modern gas appliances are designed to minimize such releases, largely for public safety reasons. The odorization of natural gas also minimizes the possibility of ongoing methane releases of any significant volume.

While difficult to quantify, it is probable that methane emissions within the gas distribution system are fairly minor both in relative and absolute terms. Intense effort is directed to ensure that this remains so. Of total methane emissions, a larger portion occurs on the upstream transmission and production system.

Natural gas produces less CO_2 per unit of energy used than any of the fossil fuels used in large quantity by households, commercial establishments and industry. In addition to its relatively low cost and abundant supply, natural gas is being looked upon to replace more environmentally harmful fuels due to global warming. Despite being more benign than other fossil fuels, the combustion of natural gas does yield carbon dioxide, a significant greenhouse gas. The problem of atmospheric concentration of greenhouse gases is international in scope and best dealt with at a national policy level.

7 NW Natural could, at some time in the future, face choices between potentially "dirty" gasification technologies, such as methane derived from coal or old tires. For the present, however, these options are not required.

NW Natural

2004 Integrated Resource Plan

Volume I: Executive Summary and Multi-Year Action Plan

Volume II: Technical Appendix

March, 2005

2004 INTEGRATED RESOURCE PLAN

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Executive Summary and Multi-Year Action Plan

Northwest Natural Gas Company

March 2005

2004 Integrated Resource Plan

<u>Volume I</u>
Executive Summary and
Multi-Year Action Plan

This Executive Summary provides an overview of NW Natural's key findings in its 2004 Integrated Resource Plan (IRP or Plan).

This document and Technical Appendix (Volume II) constitutes the company's fifth Integrated Resource Plan. Both the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC) require NW Natural to develop long-term resource plans that describe how the company plans to serve its core customers with reliable natural gas supplies and energy service at the lowest possible cost to those customers. This activity is also known as Least Cost Planning.

A BRIEF HISTORY OF OUR COMPANY

The company's roots extend deep into Oregon history. Five weeks before Oregon became a state on January 9, 1859, Portland merchants John Green and Herman C. Leonard obtained a franchise from the last territorial legislature to open a gas company. Their goal was to light Portland's streets with gas manufactured from coal. The new Portland Gas Light Company brought in coal from Vancouver Island, Australia and Japan. Gas sold for $10 for a thousand cubic feet (compared to $9.20 in 2004). A separate business, the East Portland Gas Light Company, was created in 1882 to provide service to the growing urban area springing up east of the Willamette River. Ten years later, when a 10-inch submerged line was laid across the Willamette River, the east-side business merged with the Portland Gas Company. After changing its name to the Portland Gas Light Company, it began making gas from oil in 1905 as home and water heating began replacing street lighting. Another ownership change occurred in 1910 when the company was sold to the American Power Company, which renamed the utility Portland Gas and Coke, a name it would retain until it became Northwest Natural Gas Company in 1956.

Between 1914 and 1917, the company extended distribution lines to Oregon City, Milwaukie, Oak Grove, Gladstone, Beaverton, Orenco, Hillsboro and Forest Grove. The Vancouver, Washington, gas distribution system was purchased in 1925. A line was laid to Salem in 1929 as service began to the Willamette Valley. In 1956, a new interstate pipeline brought natural gas to the Pacific Northwest for the first time and ushered in a new era of growth. The company name was abbreviated to NW Natural in 1997.

INTRODUCTION & BACKGROUND

A. Description of NW Natural

NW Natural (NW Natural or company) is a natural gas local distribution company currently serving approximately 582,000 residential, commercial and industrial customers in Oregon and Washington. NW Natural has an exclusive service area that includes a major portion of western Oregon, including the Willamette Valley and the coastal area of the state, extending from Astoria to Coos County. NW Natural also holds a certificate of public convenience and necessity from the WUTC to serve customers in Clark, Skamania and Klickitat counties in Washington.

B. Overview of Integrated Resource Planning

Integrated Resource Planning is unique to regulated utilities. Seven key components are required by Oregon and Washington regulators. NW Natural's IRP must demonstrate that the company has: 1) examined a range of demand forecasts; 2) examined all feasible means of meeting demand, including traditional supply-side, as well as demand-side, resources; 3) treated supply-side and demand-side resources equally; 4) described the company's long-term plan for meeting expected load growth; 5) described its plan for resource acquisitions between planning cycles; 6) taken uncertainties in planning into account; and 7) involved the public in the planning process.

PRINCIPAL CONCLUSIONS FROM THIS PLAN

NW Natural believes this Plan is an important guide regarding how the company intends to serve a growing region with reliable, low-cost energy supplies. With this in mind, the company has come to the following principal conclusions:

1. The company's customer base continues to grow at above-average levels, contributing to steadily rising peak day and annual gas requirements.

2. The company's existing resources are in balance with loads. Therefore, beginning almost immediately the company must add resources to assure service under peak load conditions.

3. Sequential development of underground storage reservoirs is the least-cost means of meeting our service area's growing requirements. Pre-development of storage resources ahead of core-market need, with excess capacity sold into the interstate storage market provides the least cost resource development path for core market customers.

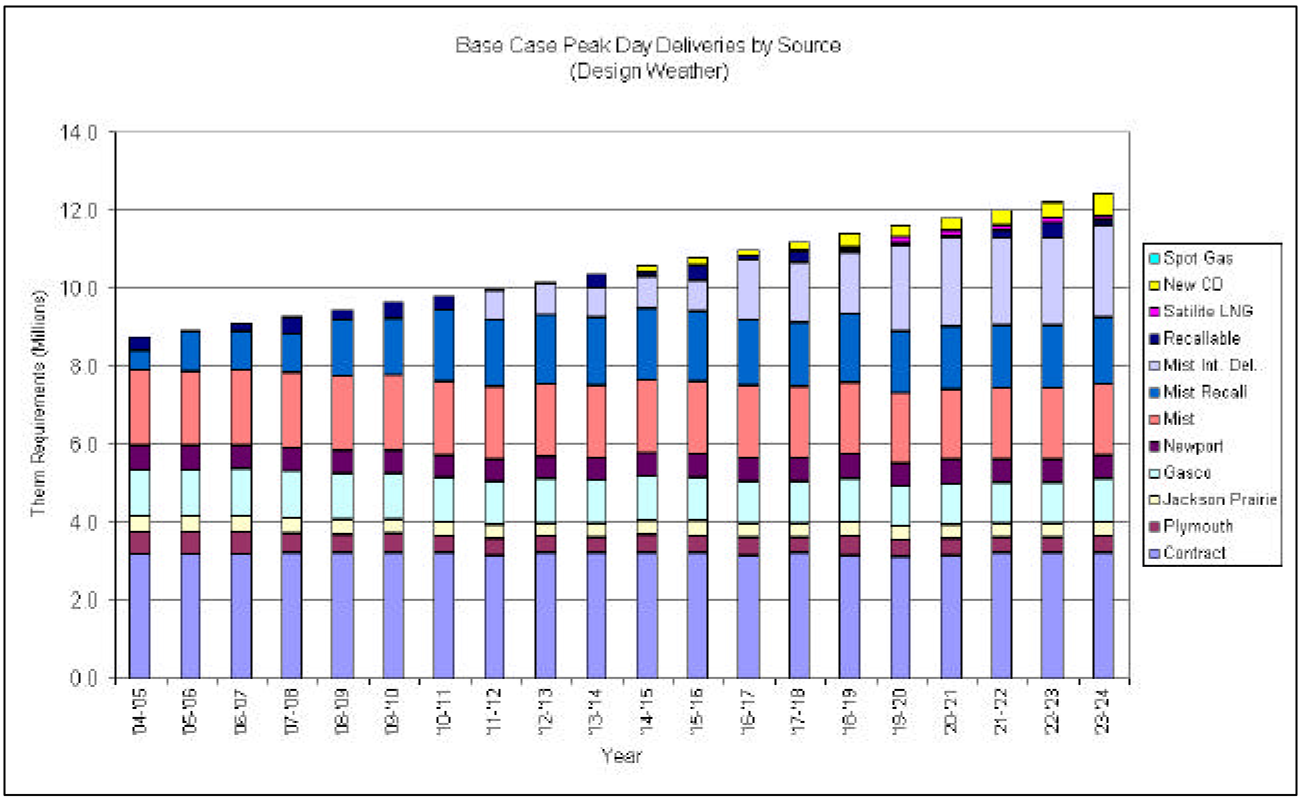
4. Current interstate pipeline capacity is adequate for the next 15 years, although minor adjustments at certain gate stations and upgrades of interstate pipeline lateral capacity may be required before then.

5. Unlike the 2000 Plan when the South Mist Pipeline Extension was identified as least cost resource, major investments in transmission or distribution system capacity are not indicated during this planning cycle.

6. In Oregon, partial decoupling and public purpose funding mechanisms create circumstances where an independent entity provides energy efficiency services on the behalf of NW Natural's core customers. The Energy Trust of Oregon performs this function and its sole responsibility is the acquisition of energy efficiency.

The shaded areas in Figure ES-1 summarize the blend of supply-side resources - gas storage and pipeline capacity - selected for the company's base case, 30-year forecast on a peak cold-day basis (only the first 20-years are shown). The "wedge" of new resources consists primarily of new pipeline contract demand, satellite liquefied natural gas, Mist integrated deliverability and the recall of existing Mist underground storage resources to core-market service. These supply-side resources are discussed more fully in Chapters B and D.

FIGURE ES-1



LOAD FORECASTS

To determine the energy requirements for the company's service area, NW Natural must identify the characteristics of its customer base. This includes the number and types of current customers, the amount of customer growth anticipated in the region, and the amount and pattern of gas usage expected by those customers.

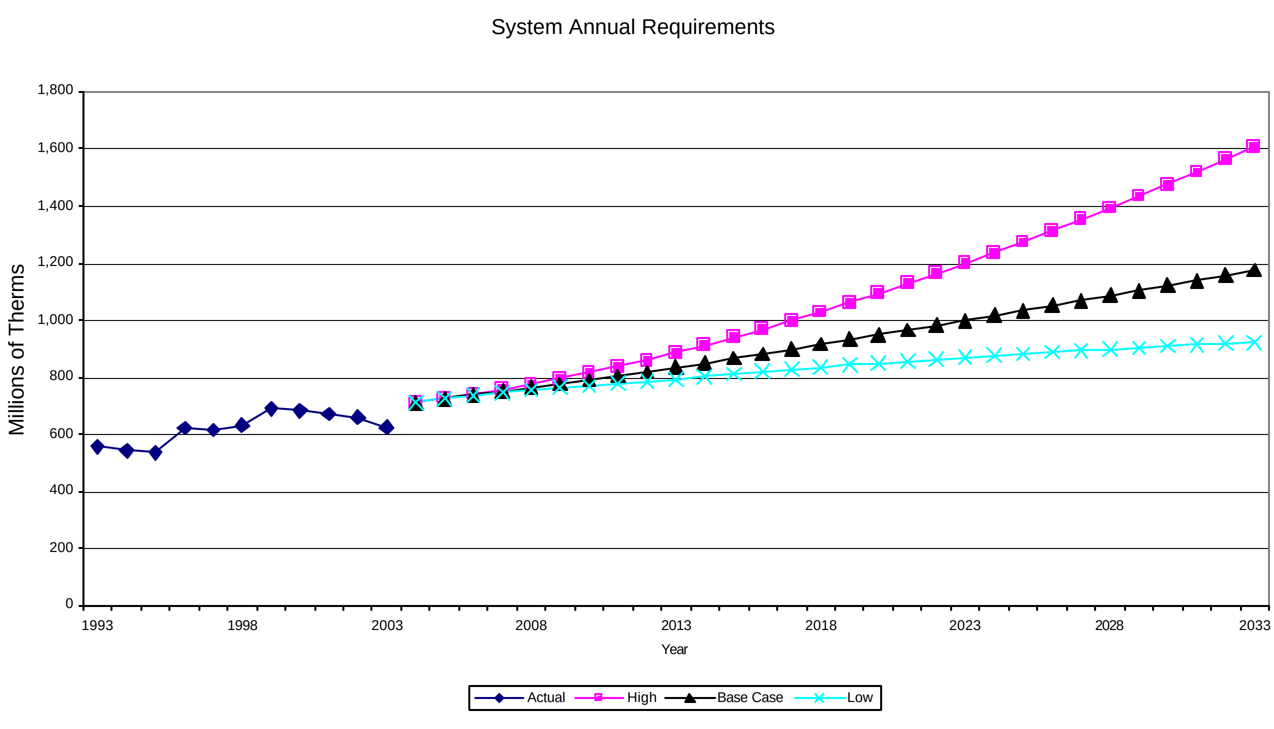
To forecast growth, NW Natural relies upon the Oregon Economic and Revenue Forecast and the Woods & Poole 2003 County Projections for Oregon and Washington. NW Natural also projects the number of customers that the company expects to convert to natural gas from other energy sources.

Scenarios used for load forecasts range from low to medium to high customer and gas usage growth. NW Natural has chosen the "medium" forecast growth scenario as its base case forecast for 30 years of daily gas requirements. It takes into account severe cold weather years and average weather conditions to evaluate the ability of the company's distribution system to meet consumer demand. This is a fundamental part of resource planning.

KEY FINDINGS:

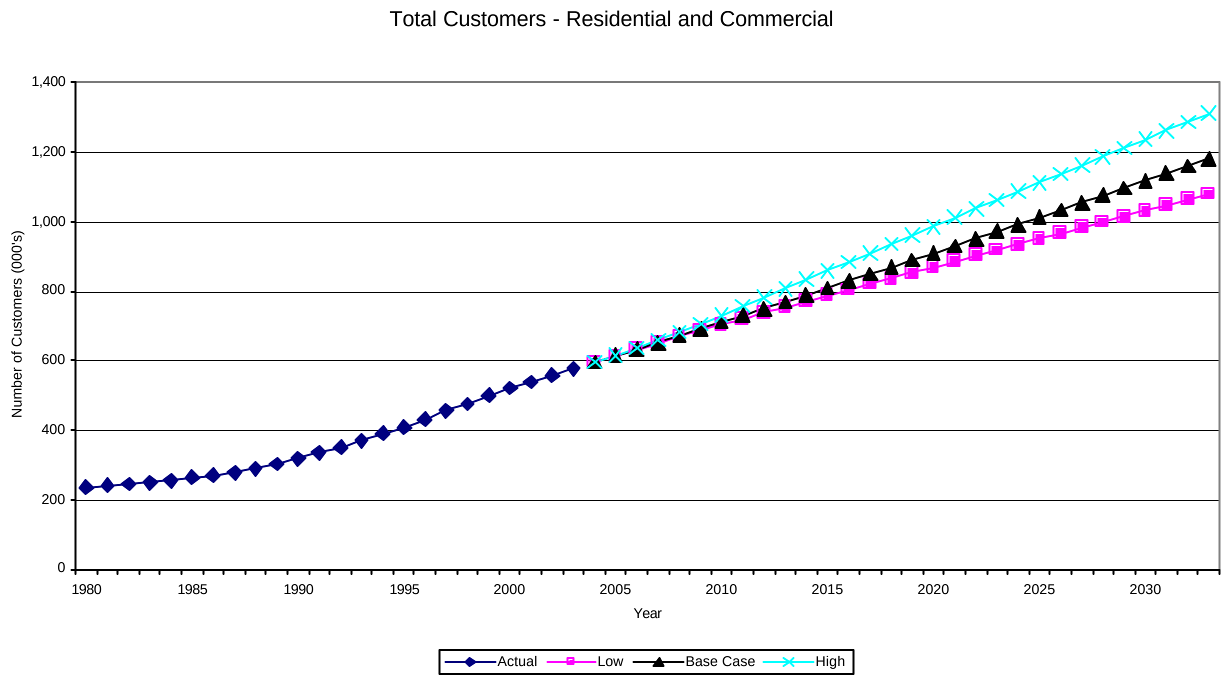
1. A "medium" forecast of annual gas requirements is the most likely scenario and is used for this planning cycle (refer to Figure ES-2).

FIGURE ES-2



2. During the next 30 years, a steady growth in the number of residential and commercial customers will occur, doubling the number of core-market customers by the end of the forecasted period (refer to Figure ES-3).

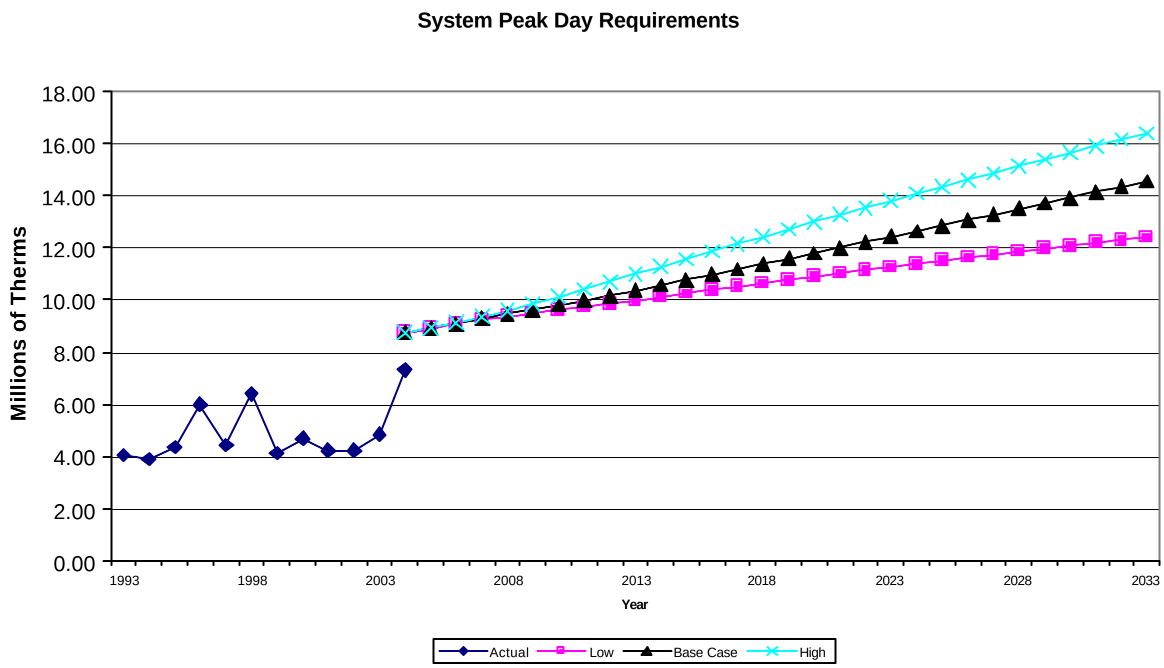
FIGURE ES-3



3. NW Natural expects new residential conversion customers to represent about 2.4 percent of convertible residences per year, or approximately 6000 conversions in the base year of the forecast. Commercial conversions from other fuels are forecast at approximately 800 per year.

4. Peak day gas requirements are projected to increase significantly during the next 30 years, rising from 8.8 million therms to more than 14.6 million therms (refer to Figure ES-4).

FIGURE ES-4



SUPPLY-SIDE RESOURCES

Supply-side resources include the gas itself, the interstate pipeline capacity needed to transport the gas to NW Natural's service area, and gas storage. The gas supply planning process is based on ensuring reliable service to NW Natural's core customers. Core customers are those who cannot switch to an alternate fuel source during periods of high or peak usage, and are unable to transport gas on their own behalf.

The amount of gas required depends on customer behavior. This behavior is greatly influenced by weather, but can also be impacted by changing business conditions and the price of fuel alternatives.

Maintaining a variety of supply sources at the company's disposal is the best means of ensuring reliable service. NW Natural's supply portfolio consists of both contracted natural gas supplies and supplies of stored natural gas. The company has access to natural gas in underground storage facilities and above-ground liquefied natural gas (LNG) storage tanks. Both storage options can be used as "peaking" resources to augment the company's distribution system.

Obviously, NW Natural's supply requirements will increase as its firm customer population grows. But the characteristics of the increased load is a key factor in the resource selection process. For example, additional water heater load can be met most efficiently by a resource that can deliver the same amount of gas year-round - a "base load" resource. Growth in heating load presents seasonal demands, and is best served with a combination of "base load" and "peaking" resources.

Given these complexities, the company has assembled a portfolio of supplies to meet the projected needs of its firm customers. At the same time, this portfolio is flexible enough to enable the company to negotiate better opportunities as they arise. Existing contracts have staggered terms, ranging from 10-year terms to very short-term arrangements of 30 days or less. This variety gives the company the security of longer-term agreements, but still allows the company to seek more economic transactions in the shorter term.

KEY FINDINGS:

1. NW Natural's supply acquisition strategy will rely on transporting gas negotiated at market rates on an annual, seasonal or monthly basis.

2. A portfolio of fixed price supplies ranging 3-years from the current period is desirable because it dampens volatility and assures more stable pricing for customers. The 3-year limit could be extended if deemed desirable and if counterparties are found who meet risk and credit standards.

3. The company's supplies are in balance with firm demand under "design day" peak conditions (coldest weather in the last 20 years). Accordingly, new storage and/or pipeline resources must continue to be added each year to meet expected firm load growth. However, price elasticity issues have materialized in the last couple of years such that load growth may be significantly more or less than customer growth would indicate, depending on the direction of future rate changes.

4. The expansion of Mist for interstate (off-system) customers fits well with the company’s resource decision-making as it avoids some of the “lumpiness” that typically accompany resource additions, allows for “just in time” recall of capacity, and virtually eliminates the development risks associated with storage expansions.

5. The company's service territory is widespread and it is not practical to consider tying together all of NW Natural's customers into a single integrated distribution system. Accordingly, some amount of incremental upstream pipeline capacity may be needed to serve the more isolated portions of the company's system.

6. Conversely, as the cost of upstream pipeline expansions increase, it may be cost-effective for NW Natural to remove bottlenecks and more fully integrate certain portions of its own distribution system.

7. The need for supply diversity has been underscored by the ruptures and resulting federal order in 2003 that Northwest Pipeline Corporation (NPC) must replace its 26” mainline from the Canadian border to NW Natural’s service territory by December 2006. Cost-effective opportunities to improve supply path diversity should be pursued.

SUPPLY DIVERSIFICATION

Over the twelve years since NW Natural began purchasing supplies for its customers directly in the market, rather than from the interstate pipeline, the company pursued a diversified approach to acquiring supply resources. This included expanding gas receipt points to allow new gas supplies to be purchased from, and stored in, Alberta, Canada, as well as traditional supply basins in British Columbia and the U.S. Rockies. Diversification has given the company competitive options and improved service reliability on the interstate pipeline system. NW Natural believes that the availability of supply, the large existing pipeline infrastructure in Canada, the number of industry players active in the region, and the fluidity of the market will yield reliable, market-priced supplies for years to come.

For the next several years, expansion and diversification of Mist storage will be NW Natural’s primary focus for developing its supply portfolio. Mist is an exceptional resource for NW Natural due primarily to its location within the service territory. Because of its location, the resource is available without the need for winter re-delivery on the interstate pipelines, which both reduces cost to customers and enhances service reliability. Underground storage and related infrastructure developments in Oregon provide equivalent benefits for Washington customers, as storage permits the company to displace north to south flowing pipeline supplies to more northerly delivery points in Washington.

RECENT RESOURCE DECISIONS

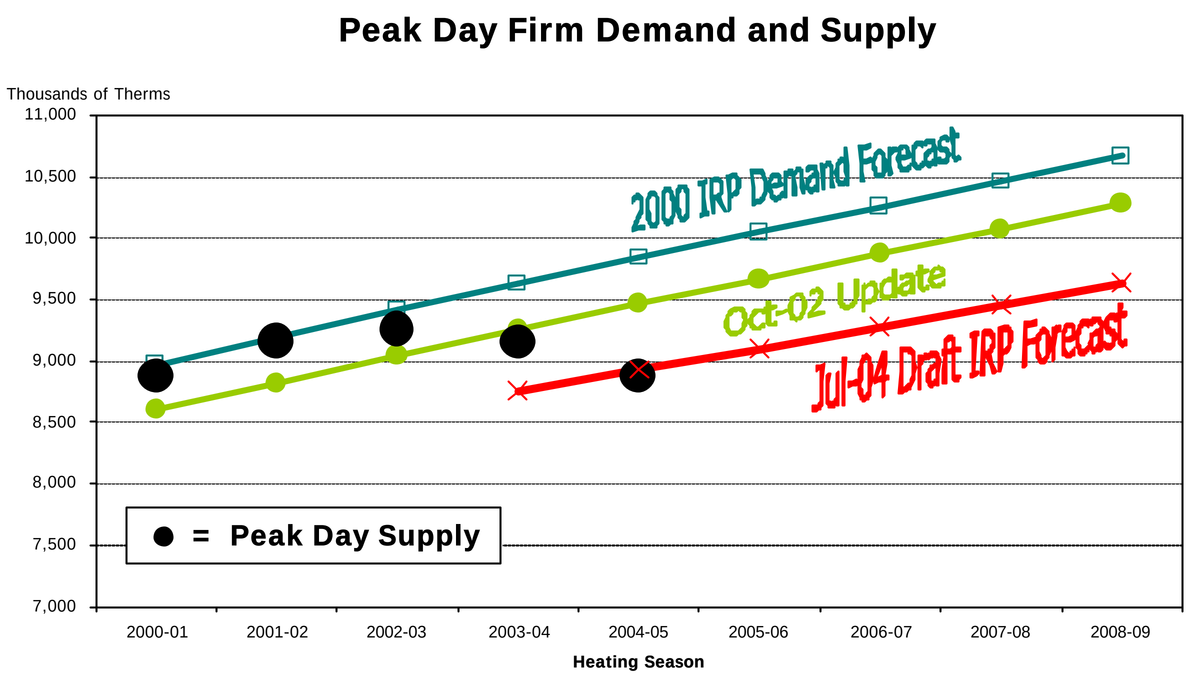
Included in the company's portfolio of current gas supply are resources added since the development of the company's 2000 IRP in response to continued robust customer growth, and in anticipation of future growth. These additions generally followed supply-related conclusions and action plan steps developed in the 2000 IRP.

Prior to 2003, the last increment of Mist expansion completed for core customers was a project that, in late 1999, added almost 28 miles of 24" piping to loop the existing South Mist Feeder from Miller Station to a point at the western edge of the Portland metropolitan area (Bacona). While reservoir and Miller Station additions and improvements subsequently were made, the capacity had to be marketed to interstate (off-system) customers due to the extended length of the authorization process for SMPE, which did not receive final permission to be built until November 2003.

The first segment of SMPE was completed in late 2003. Rather than follow the original plan of working from north to south, a 12 mile section instead was built from the southern terminus at the Molalla gate station to its first interconnection further north with the company's high pressure distribution system near Aurora. This connection allowed higher flows and pressures from the NPC system, which were critical to that southern portion of the Portland-area distribution system during the cold weather event experienced in early January 2004.

The remaining 50 miles of SMPE was completed in the Fall of 2004, finally allowing the company to access more Mist deliverability. This will mark the first "recall" of Mist capacity developed in advance of core need, which had been marketed to the interstate market during the past three years. Resources needed to bridge the gap until SMPE is completed, including baseload deliveries of supplier gas at the "citygate" and other peaking arrangements, have or will be allowed to terminate. The resulting pattern of load forecasts and peak day supplies since the 2000 IRP are shown in Figure ES-5:

Figure ES-5



FUTURE RESOURCE ALTERNATIVES

NW Natural is considering the following resource options for new pipeline and storage capacity:

Interstate Pipeline Capacity Additions - Increasing interstate pipeline delivery capacity can either be done in a short period of time, or it can require an expensive, time-consuming effort. Strategies exist to reduce the risk of excess capacity additions, such as partnerships with other local distribution companies and pipelines. In the upcoming planning cycle, due to NPC open seasons, the company has opportunities to choose expanded capacity on the Grant's Pass Lateral, and will have opportunities for mainline capacity expansions.

Mist Expansion - NW Natural receives underground storage service at its Mist facility from three depleted production reservoirs. Opportunities to expand the current facility or develop new underground storage are being explored. Among the options are increased injection-withdrawal capacity at existing reservoirs, possible now because of new drilling technologies; adding more seasonal capacity at existing reservoirs by reclaiming lost capacity due to water intrusion; and examining 40 additional production reservoirs in the Mist area. Other storage projects may come available and may be cost-competitive with Mist, such as Jackson Prairie, and will be considered when offered by the market.

Molalla Hub – With the SMPE completed, a "hub" facility at the point of connection between SMPE and the facilities of NPC at Molalla creates the opportunity to move Mist gas North on NPC without expansion, and South without need for expansion of the Grant's Pass Lateral.

Newport Expansion - The daily deliverability of gas from NW Natural's Newport liquefied natural gas plant could be increased from 600,000 therms per day to 1,000,000 therms per day. The cost of infrastructure additions would be about $24.8 million. While this would enhance NW Natural's system reliability during periods of peak demand, NW Natural would have to add or upgrade major segments of its distribution system to move the gas.

Valley Feeder - A new pipeline could move natural gas from the Mist underground storage facility south to the Salem area, and then continue further south to Albany or Eugene if necessary. This project would work in conjunction with a new pipeline from Newport and is an alternative to continued expansion of NPC's Grant's Pass Lateral.

DEMAND-SIDE RESOURCES

The 2004 Plan marks a major change in the way the company deals with demand-side resources. Since publication of the 2000 Plan, a great deal has changed with respect to the company's approach to energy efficiency (EE). The combination of the approval of a partial decoupling mechanism in the state of Oregon and the implementation of a public purpose funding mechanism administered by the Energy Trust of Oregon (ETO) allows the company to take a more facilitative rather than administrative role in the development and delivery of conservation programs. At the same time, these developments align ratepayer and shareholder interests in the pursuit of energy efficiency.

Decoupling refers to the mechanisms developed in the Oregon UG 143 docket to partially sever the relationship between sales levels and earnings levels. It partially addresses the problems faced by a utility whose costs are essentially fixed but has revenues highly dependent on customers' gas consumption behavior.

Public purpose funds are collected from Oregon residential and commercial ratepayers and are used by the ETO to finance residential and commercial EE investments. In addition, funds are collected and used by the company to fund low-income weatherization and low-income bill payment assistance in Oregon. In Washington, low income weatherization is accomplished using deferred accounting.

After the ETO has established a record and has been able to perform measurement and evaluation studies focused on gas EE programs and their performance, the company will attempt to implement the most highly cost effective programs in Washington using ETO energy service contractors, but not the ETO itself.

In the next IRP cycle, enough should be known about ETO program performance to allow the inclusion of ETO as a demand-side resource to be selected or rejected by the optimization model presented in Chapter D.

<u>KEY FINDINGS</u>

1. In this IRP planning cycle the company adjusts its long-term demand forecast by the projected energy savings expected by the Energy Trust of Oregon without attempting to evaluate ETO conservation programs.

2. If estimated savings are fully realized, the ETO's activities through 2012 will save an amount of annual energy equivalent to about 1.4 years of growth in the Northwest Natural system.

3. Demand response strategies such as seeking out firm customers that can be curtailed during peak periods are severely limited because so many of the company's customers already take service on interruptible rate schedules.

4. The company will continue to work with and encourage the ETO to pursue cost effective energy efficiency improvements and clone successful ETO programs for its Washington service area.

5. The company will pursue revenue-per-customer decoupling in Washington and implement the ETO's cost effective energy efficiency programs in Washington.

IMPACT OF RELATED ENVIRONMENTAL COSTS ON NW NATURAL'S DSM STRATEGY

Related environmental costs do impact demand-side resource choices. Recognizing the cost of carbon dioxide damage could have the greatest impact on the company's avoided costs. The most likely vehicle through which carbon dioxide costs could be imposed on energy users is through a national carbon tax or Green House Gas mitigation strategies coming out of the West Coast Governors' Task Force on Green House Gases. However, it is unlikely that a carbon tax or its equivalent will be levied in the near future.

If a carbon tax were imposed, more of the demand-side resource options would be cost-effective. Adding a carbon tax of $40 per ton adds $0.24 per therm to the company's avoided costs. This could drive up the implicit commodity cost of natural gas and therefore make some non-cost-effective conservation measures cost-effective.

OTHER DEMAND-SIDE MANAGEMENT CONSIDERATIONS

LOAD MANAGEMENT

Following the 2000-01 energy crisis, energy planners' attention focused on a group of activities generally known as demand response. Its general purpose is to help manage demand during periods of system stress. The term encompasses a number of activities including real time pricing, time of use rates, critical-peak pricing, demand buyback, interruptible rates, and direct load controls. To varying degrees, several of these techniques to manage peak demands are used by Northwest Natural.

The company does not acquire firm resources to meet interruptible customer requirements under design peak day conditions. To the extent that current firm core-market customers permanently switch to interruptible service, peak day capacity requirements for core-market customers are reduced.

On the NWN system, customers taking service on interruptible rates represent approximately 42 percent of annual throughput. This includes interruptible sales service, interruptible transportation service and firm on our system transportation service where the transporter, not the company, is responsible for the firmness of upstream pipeline capacity arrangements. Interruptible service is very attractive for large volume customers because of the low distribution margin involved. As a result, all cutomers that can manage their operations on interruptible service are currently served on an interruptible basis – leaving little opportunity to reduce peaks loads through expanded interruptible service.

RATE DESIGN

In general, the company believes that rate design policies should encourage year-round energy efficiency and cause customers to not place excessive demands on the system during severe weather episodes. The company also believes that revenue stability is desirable. Toward these ends, the company's initiatives with respect to the partial decoupling mechanism and the WARM mechanisms in Oregon strike a reasonable balance.

Most parties recognize that the company's cost of performing the distribution function is fixed. With the exception of the incremental cost of upstream capacity (or its substitutes like underground storage), distribution system costs are almost entirely independent of the amount of gas a residential customer consumes on an annual basis. This creates a situation that begs for straight-fixed-variable pricing.

The combination of company's partial decoupling and WARM mechanisms in Oregon allow a reasonable compromise between the extremes of collecting fixed system costs primarily through customer charges or collecting fixed costs primarily with volumetric charges. For residential and small commercial customers we have retained the existing approach of recovering the bulk of fixed system costs through volumetric charges. Thus, the marginal cost of comfort is kept high, customer charges are kept relatively low, and revenues are substantially stabilized through the partial decoupling and WARM mechanisms.

Beyond this, declining block rates for residential and small commercial customers have now been eliminated in the company's Washington service area. Thus, we have improved the provision of price signals with respect to environmental and global warming concerns, but we have also increased revenue instability in Washington.

With respect to Demand Side Resource planning in Washington, the major remaining step is to establish Revenue Per Customer Decoupling for residential and commercial class customers following the blue print set forth in the company's Initial General Rate Case Testimony and proposed Schedule 220 in the Washington UG 031885 docket (go to: http://www.wutc.wa.gov/rms2.nsf?Open).

DSM ACTIVITIES' IMPACT ON SMALL BUSINESS

Where incentives are proposed in the residential equipment markets, equipment distributors and dealers have been encouraged to sell high-efficiency equipment. NW Natural's participation in DSM activities through public purpose funding has a positive economic impact on smaller companies involved in providing energy conservation services.

PUBLIC COMMUNICATION AND PARTICIPATION

TECHNICAL WORKING GROUP

The Technical Working Group brings together professionals representing a variety of entities with an interest in NW Natural's IRP process. Participants in the TWG during for this Plan's development included representatives from the Citizens' Utility Board; Energy Trust of Oregon; Northwest Power and Conservation Council; National Energy & Gas Transmission; Northwest Industrial Gas Users; Avista Corporation; Northwest Pipeline Corporation; Williams Northwest Pipeline; the Oregon Public Utility Commission; and the Washington Utilities & Transportation Commission. This group continues to be an integral part of plan development.

PUBLIC PARTICIPATION

NW Natural's customers, TWG members, and interested parties were invited to participate in one or both of two (2) public meetings.

The first public meeting was held in Salem at NW Natural's offices on May 11, 2004; the second meeting was held in Portland at NW Natural's main office on May 25, 2004. Attendance at the public meetings was sparse. Questions from the public were primarily related to long-term supply adequacy, the location of the South Mist Pipeline Extension route, and the manner in which pipeline easements are acquired.

2004 Integrated Resource Plan

Multi-Year Action Plan

1.0 Demand Forecasting

1.1 Refine methods for district level forecasting of customer gains and losses.

1.2 Refine methods for district level forecasting of use per customer.

1.3 Recalibrate forecast for changes in gas usage equations and expected customer gains following each heating season. Assess implications and report to state Public Utility Commissions as appropriate.

2.0 Supply-Side Resources

2.1 Refine cost estimates for Grants Pass Lateral enhancements and the joint development marginal storage reservoirs and Willamette Valley Feeder segments. Marginal storage reservoirs are those known to exist but not included as resource options in this Plan.

2.2 Continue to recall daily and annual underground storage capacity from the interstate stoarge gas market to core market service as needed. Based on this Plan, the company expects to recall 200,000 therms per day of deliverablity in both 2005 and 2006.

2.3 Evaluate benefits and costs of marine liquefied natural gas facilities located in the pacific northwest.

3.0 Demand-Side Resources

3.1 Continue to work with the Energy Trust of Oregon in efforts to improve energy efficienty delivery programs and program participation rates.

3.2 Seek approval of revenue per customer decoupling in the state of Washingtion.

3.3 Coordinate and fund an independent review of the Oregon partial decoupling mechanism.

3.4 Evauate the cost effectiveness of Energy Trust of Oregon, Oregon Low-Income Energy Efficiency, and Washington energy efficiency programs.

4.0 Linear Programming Model and Least Cost Plan Integration

4.1 Continue development of an LP-based dispatch model for the evaluation of short term gas procurement and supply-side resource dispatch designs.

4.2 Continue to improve the specification of a spatially-diversified nodal LP model for capacity planning in the development of the company's next IRP.

4.3 Throughout the current and future planning cycles, evaluate Mist underground storage options against other alternative sources of capacity. Such alternatives include capacity release by other utilities, participation in other storage projects, pipeline open seasons for new capacity, and the use of these emerging alternatives as potential bridging resources that allow shifting core-market Mist storage development costs forward in time.

5.0 Avoided Cost Determination

5.1 No changes in methodology are anticipated, conduct periodic updates as appropriate.

6.0 Public Involvement

6.1 Conduct Technical Working Group and Public Involvement meeting as appropriate.

CHAPTER F: PUBLIC COMMUNICATION AND PARTICIPATION

CHAPTER F: PUBLIC COMMUNICATION AND PARTICIPATION

This chapter describes the steps NW Natural took to involve the public in developing this Plan.

I. TECHNICAL WORKING GROUP

The Technical Working Group (TWG) is an integral part of Plan development. Participants in the TWG during for this Plan development included representatives from the Citizens' Utility Board; Energy Trust of Oregon; Northwest Power and Conservation Council; National Energy & Gas Transmission; Northwest Industrial Gas Users; Avista Corporation; Northwest Pipeline Corporation; Williams Northwest Pipeline; the Oregon Public Utility Commission; and the Washington Utilities & Transportation Commission. The names of participating TWG members are shown in Appendix F, on page FF-1.

TWG participation was solicited in March and April 2004. NW Natural solicited TWG members from a list of TWG participants in prior planning cycles. To date, two technical conferences have been held during the Plan development process: the first on April 12, 2004, and the second on May 10, 2004. Pages FF-2 through FF-9 detail the Agenda topics of each of the TWG meetings.

II. PUBLIC PARTICIPATION

NW Natural's customers, TWG members, and interested parties were invited to participate in one or both of two (2) public meetings. Customers were notified about the meeting by way of a bill insert in the April billings. A copy of the notice is included in Appendix F at pages FF-10.

The first public meeting was held in Salem at NW Natural's offices on May 11, 2004; the second meeting was held in Portland at NW Natural's main office on May 25, 2004.

Attendance at the public meetings was sparse. Besides NW Natural employees and representatives from the Oregon Public Utility Commission, only one person attended the May 11th meeting held in Salem. There were three members of the public in attendance at the Portland meeting on May 25th.

The structure of the meetings was informal. NW Natural used a slide show presentation to depict the planning process, the key elements that NW Natural looks at when developing the plan, as well as the principal findings. The PowerPoint presentation was also made available to interested persons electronically and by mail on request. There were 23 requests for an electronic copy. A copy of the presentation is shown in Appendix F at pages FF-11 through FF-43.

Questions from the public were primarily related to long-term supply adequacy, the location of the South Mist Pipeline Extension route, and the manner in which pipeline easements are acquired.

2004 DRAFT INTEGRATED RESOURCE PLAN SYNOPSIS

NW NATURAL

May 11, 2004

About NW NATURAL

NW Natural (NWN), formerly known as Northwest Natural Gas Company is a natural gas local distribution company currently serving approximately 580,000 residential, commercial and industrial customers in Oregon and Washington.

NWN's service area includes a major portion of western Oregon, including the Willamette Valley and the coastal area of the state, extending from Astoria to Coos Bay.

NWN also holds a certificate of public convenience and necessity from the WUTC to serve customers in Clark, Skamania and Klickitat counties in Washington.

A Brief History of Our Company

NW Natural

The company's roots extend deep into Oregon history. Five weeks before Oregon became a state on January 9, 1859, Portland merchants John Green and Herman C. Leonard obtained a franchise from the last territorial legislature to open a gas company. Their goal was to light Portland's streets with gas manufactured from coal. The new Portland Gas Light Company brought in coal from Vancouver Island, Australia and Japan. Gas sold for $10 for a thousand cubic feet (compared to $9.20 in 2004). A separate business, the East Portland Gas Light Company, was created in 1882 to provide service to the growing urban area springing up east of the Willamette River. Ten years later, when a 10-inch submerged line was laid across the Willamette River, the east side business merged with the Portland Gas Company. After changing its name to the Portland Gas Light Company, it began making gas from oil in 1905 as home and water heating began replacing street lighting. Another ownership change occurred in 1910 when the company was sold to the American Power Company, which renamed the utility Portland Gas and Coke, a name it would retain until it became Northwest Natural Gas Company in 1956.

Between 1914 and 1917, the company extended distribution lines to Oregon City, Milwaukie, Oak Grove, Gladstone, Beaverton, Orenco, Hillsboro and Forest Grove. The Vancouver, Washington, gas distribution system was purchased in 1925. A line was laid to Salem in 1929 as service began to the Willamette Valley. In 1956, a new interstate pipeline brought natural gas to the Pacific Northwest for the first time and ushered in a new era of growth. The company name was abbreviated to NW Natural in 1997.

Our Approach to Integrated Resource Planning

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This document summarizes interim results in the process of developing the company's fifth Integrated Resource Plan.

Long-term planning efforts point the way to resource acquisitions that serve core customers with reliable natural gas supplies and energy service at the lowest possible cost.

At this point in time a Base Case Forecast and Supply Response has been developed that hopefully provides enough information for energy professionals and lay persons to understand the Plan's assumptions, methods of analysis, and the company's conclusions.

This "Slide Show" captures the principal findings of the Plan and tries to do so in a way that permits general audiences to understand the more important technical issues.

Required Plan Elements

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Integrated Resource Planning is unique to regulated utilities. Oregon and Washington regulators require seven key components in their Least Cost Planning rules.

NWN's IRP must demonstrate that we have:

- Examined a range of demand forecasts;
- Examined all feasible means of meeting demand, including traditional supply-side, as well as demand-side, resources;
- Treated supply-side and demand-side resources equally;
- Described the company's long-term plan for meeting expected load growth;
- Described the intended resource acquisitions between planning cycles;
- Taken uncertainties in planning into account;
- Involved the public in the planning process.

Opportunities for Participation and Comment

Date	Event	Comments
August through March of 2004	Company develops 2004 Draft IRP with internal workshops	*Ad hoc* external consultations where appropriate
ASAP (so last billing cycle arrives before May 1st)	Launch bill inserts announcing 2004 Plan, all public meetings, and include a form for requesting copies of the Plan's Synopsis	Also, Up date Interested Parties List based on responses and personnel changes at energy industry companies and regulatory oversight agencies
March 29	Internal draft Plan review with Senior Management	
April 1	E-mail Power Point Plan synopsis to interested Parties List	
April 12, 26, May 10, 24	Hold Technical Working (advisory) Group meetings. Draft chapters distributed during the TWG review process	**All in Portland Headquarters, Hospitality Room. Meetings scheduled from 10:00 to 3:00. Please mark your calendars.**
May 11 and 25	2 public meetings	One at Portland Headquarters Building, other in Salem
June 7	Comments due to NWN on Draft Plan and TWG proceedings	Date may be extended if necessary
July 23	**NWN releases final draft Plan and narrative Plan synopsis**	Plan synopsis distributed to those customers requesting a copy
August 3 or 10	OPUC Commission Briefing on Plan in Oregon	
August 9	OPUC Issues Notice of Pre-Hearing Conference	

Opportunities for Participation and Comment (continued)

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Date	Event	Comments
August 25	OPUC Pre-Hearing Conference	
September 8	Initial comments on final draft due to OPUC Staff	Allows 6 weeks for comments
September 22	OPUC Staff distributes draft Order	
October 6	Comments due to OPUC Staff	2 weeks for comments
October 20	Final memo and order to OPUC Commissioners	
November 9	OPUC Commission acknowledgement of plan	Commission requests at least 2 weeks to review memo
TBA	WUTC Commission Briefing on Plan in Washington	

2004 Budget Volumes - By Customer Rate Class

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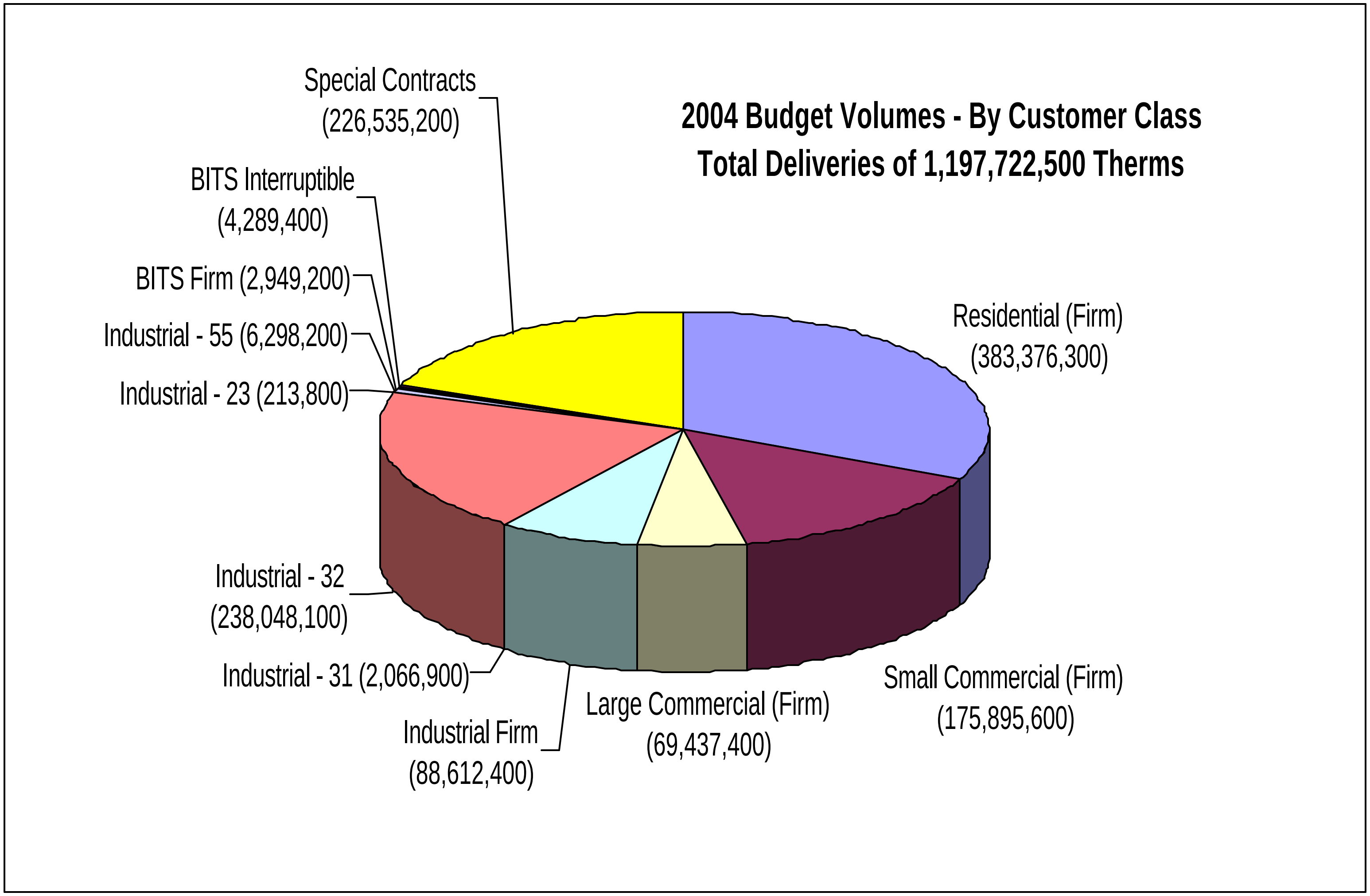
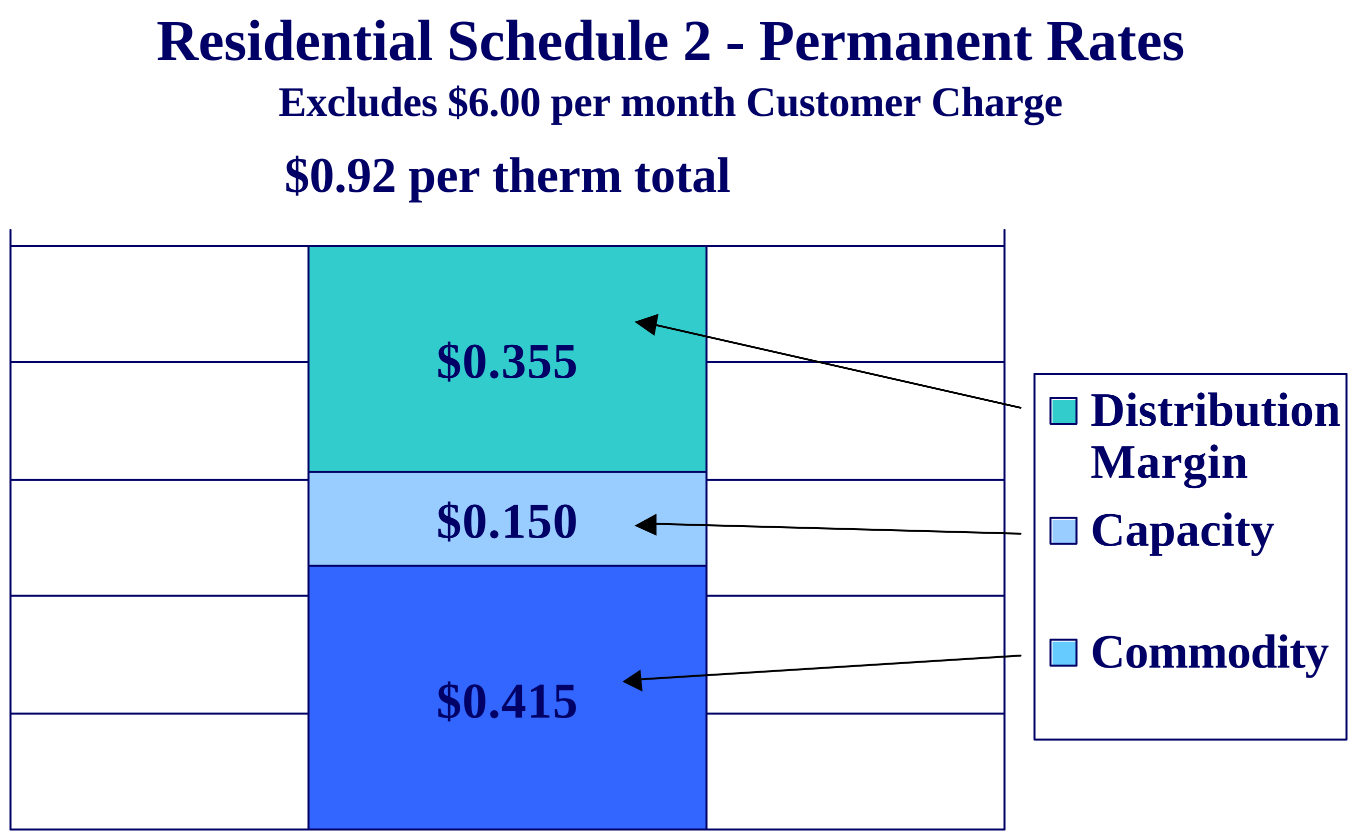


Illustration: Oregon Rate Components



Meeting Peak Day and Seasonal Gas Requirements

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Our #1 Commitment:

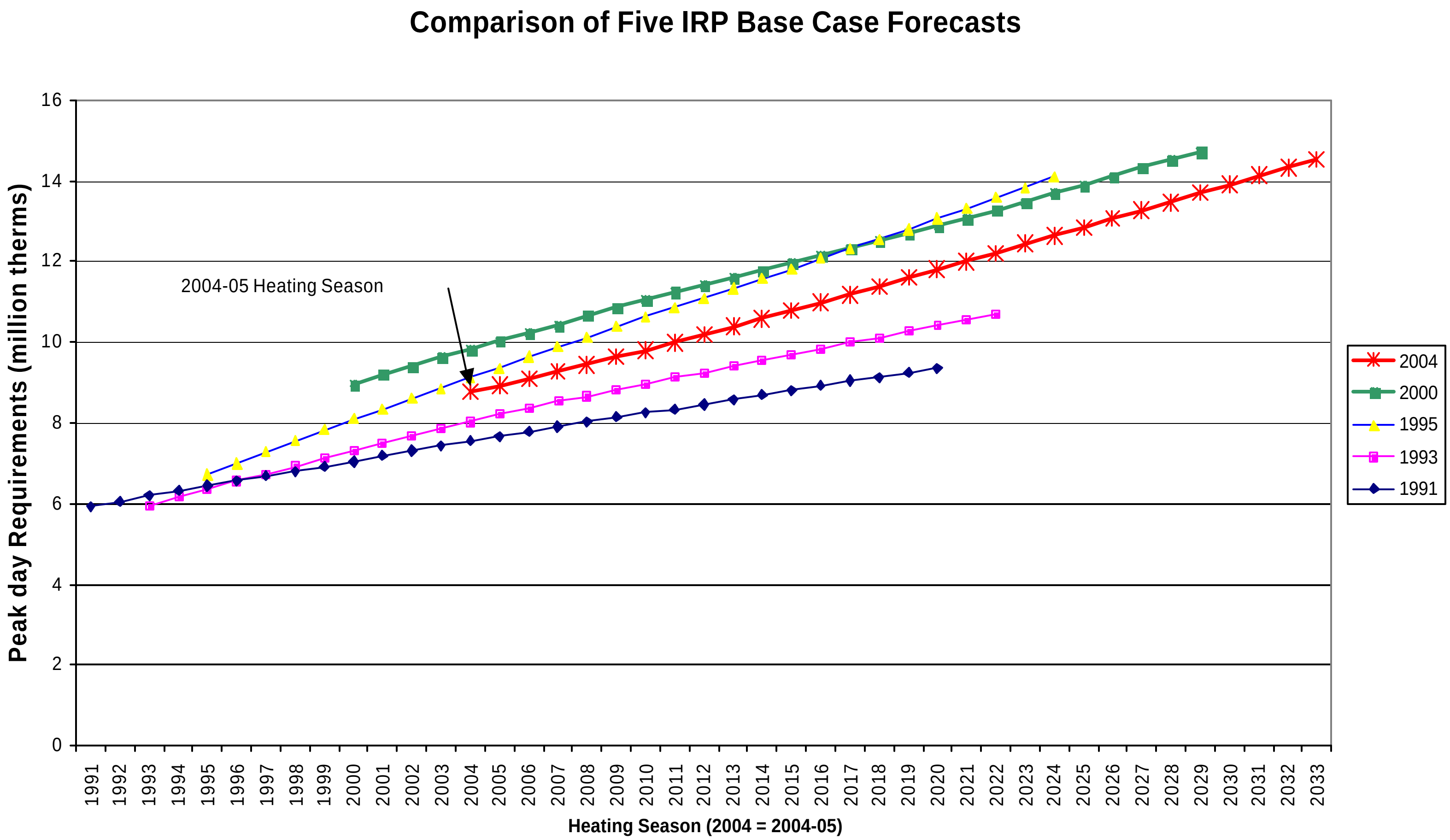
- To provide reliable service to our firm customers under anticipated severe cold weather conditions

We Plan for Firm Customer Needs in Advance:

- Secure delivery capacity* - Ensure gas can be delivered
- Purchase commodity gas - Ensure gas is available
- We use hedging strategies to minimize price volatility

* We do not plan capacity additions to meet the needs of our interruptible customers during severe weather

30-Year Peak Requirements Forecast Comparisons



Peak Weather Degree Day Distributions

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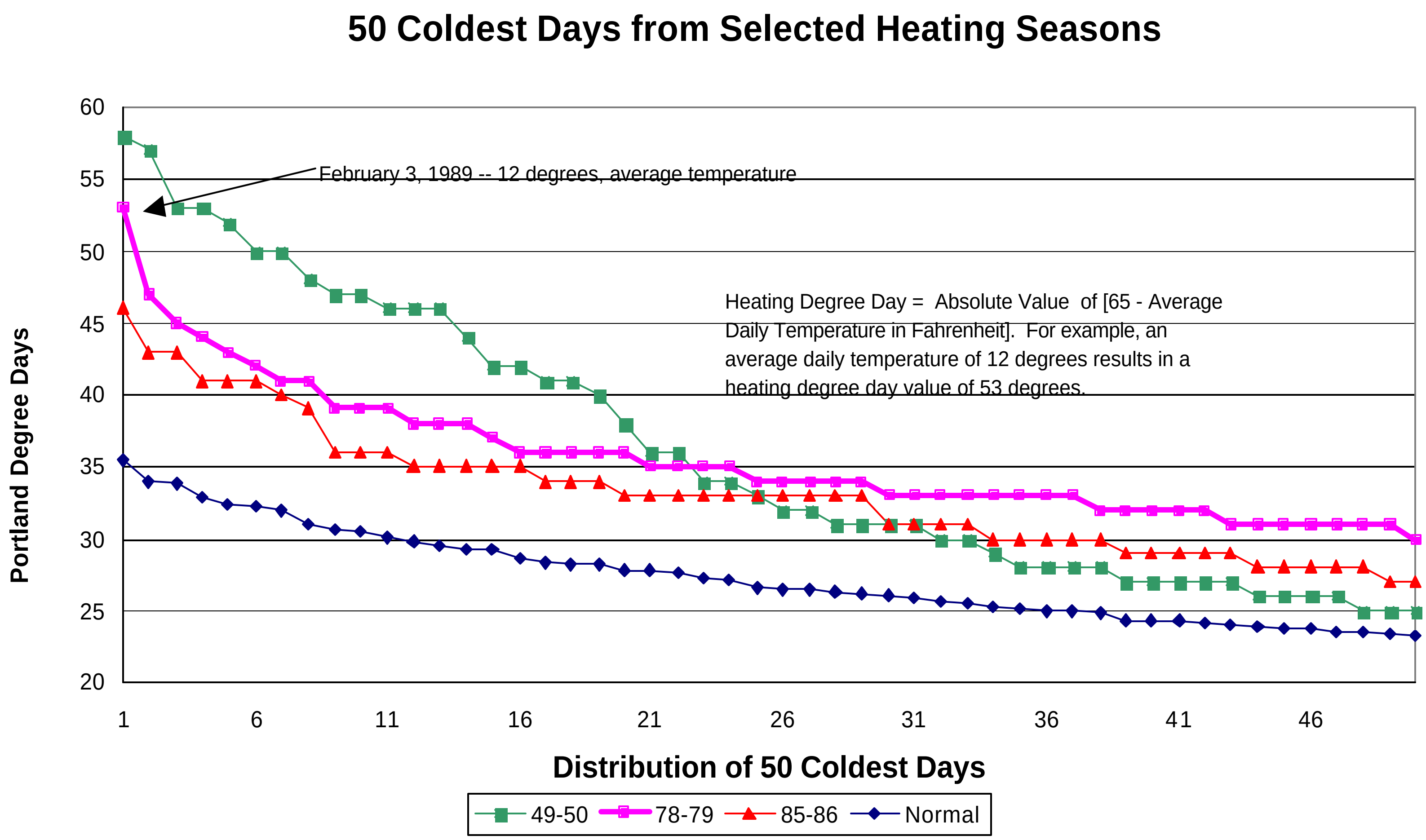
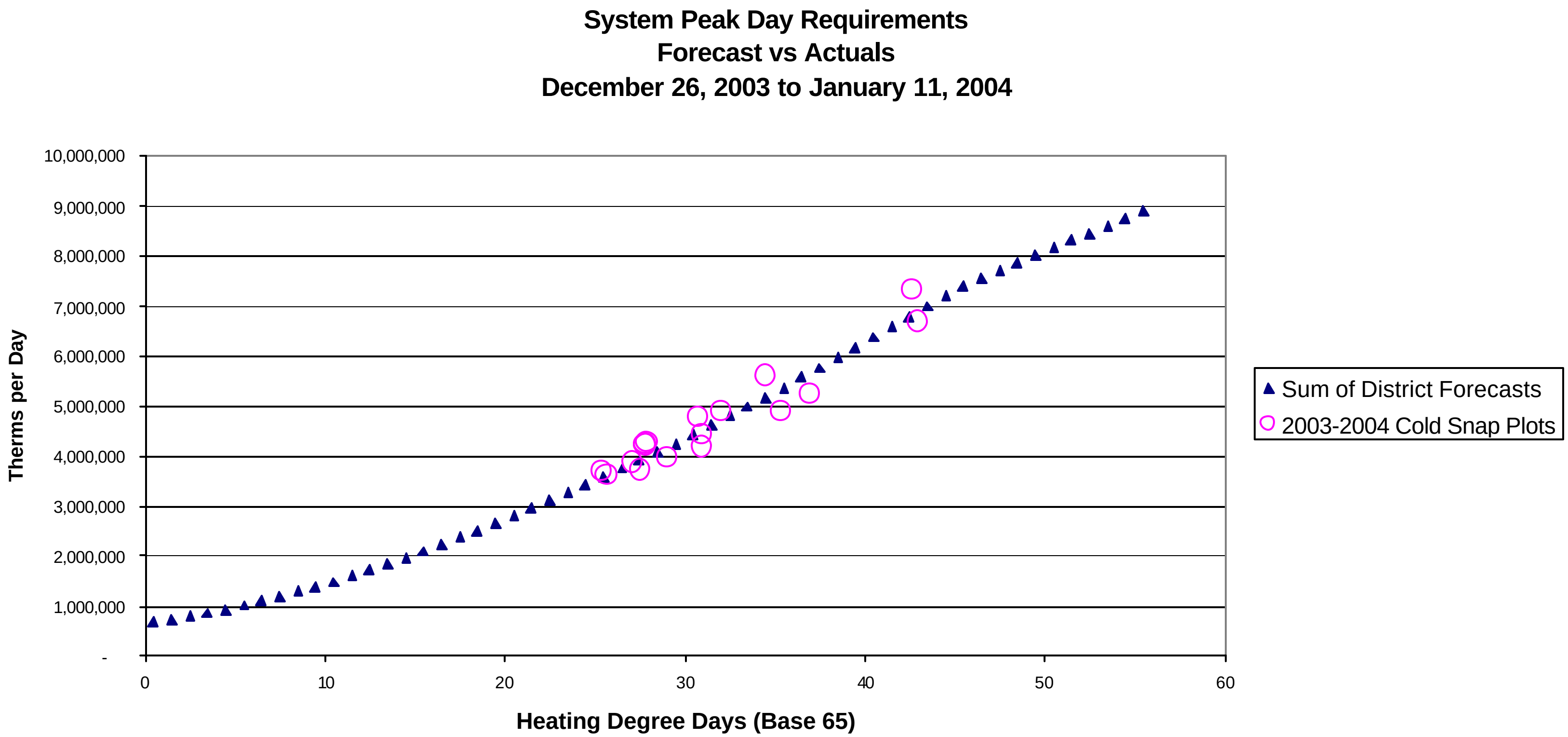
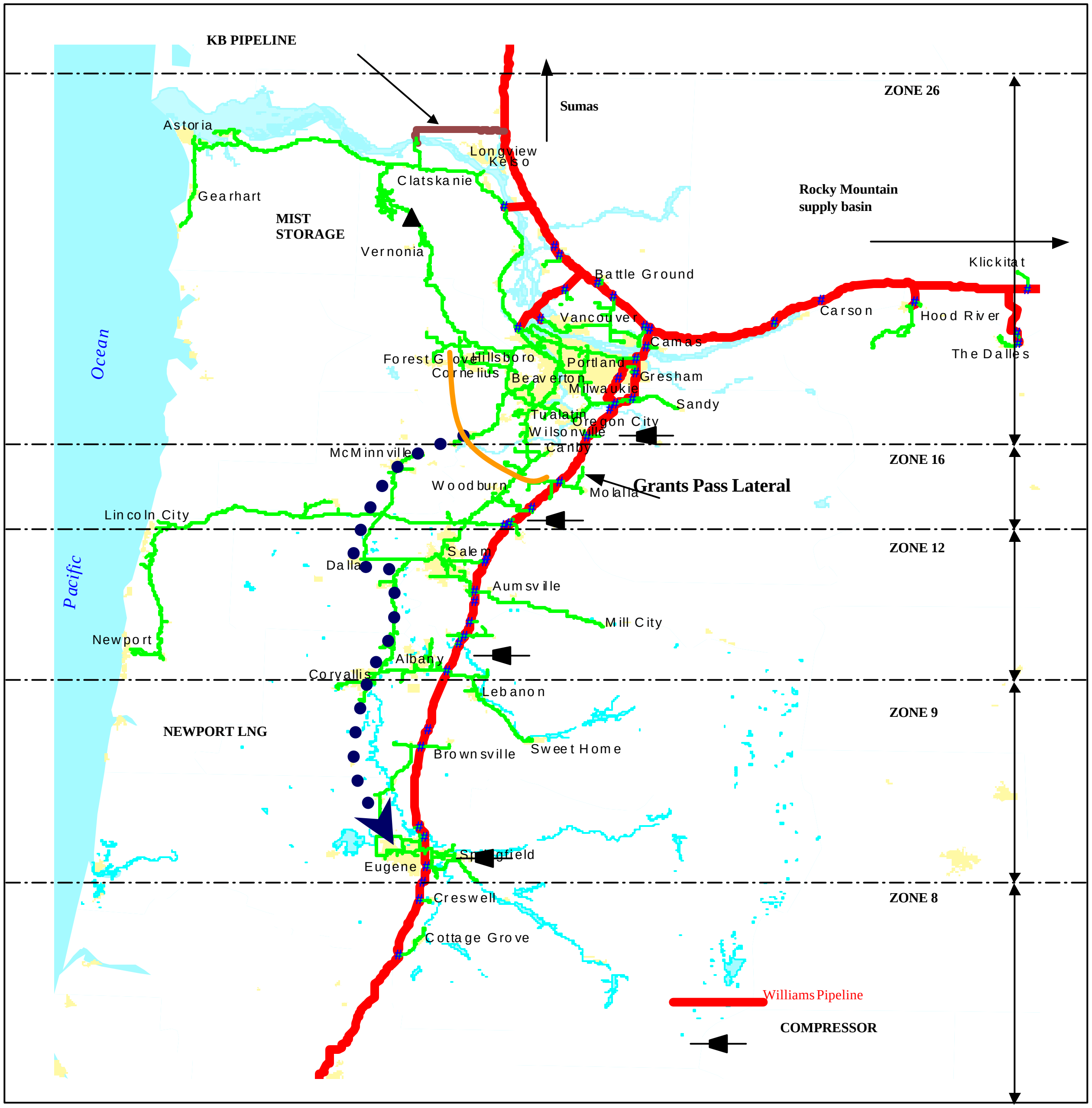


Forecast Model Performance During Recent Cold Snap




KB PIPELINE
Sumas
ZONE 26
Astoria
Longview
Kelso
Clatskanie
Gearhart
MIST
STORAGE
Vernonia
Rocky Mountain
supply basin
Klickitat
Battle Ground
Carson
Hood River
Vancouver
Camas
The Dalles
Ocean
Forest Grove
Hillsboro
Cornelius
Portland
Beaverton
Gresham
Milwaukie
Sandy
Tualatin
Oregon City
Wilsonville
Canby
McMinnville
ZONE 16
Woodburn
Molalla
Grants Pass Lateral
Lincoln City
ZONE 12
Salem
Dallas
Pacific
Aumsville
Mill City
Newport
Albany
Corvallis
Lebanon
ZONE 9
NEWPORT LNG
Brownsville
Sweet Home
Springfield
Eugene
Creswell
ZONE 8
Cottage Grove
Williams Pipeline
COMPRESSOR

Incremental Supply-Side Resource Stack

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Pipeline Capacity:

- "Open seasons" for capacity on Gas Pipelines occur over time with approximate 5-year intervals between open seasons.
- Pipeline capacity choices require both enabling pipeline capacity (Canadian pipelines) and sometimes require local infrastructure investments.

Willamette Valley Feeder

- Potential alternative to pipeline capacity that would move gas from underground storage at Mist Oregon to destinations as far south as Eugene in a corridor west of the Interstate 5 Freeway.

Underground Storage Development:

- Reservoirs, injection/withdrawal wells, observation wells, injection of cushion gas and working gas inventory.
- Gathering systems, gas treatment (water removal), compressors, control systems, and feeder pipelines to move gas to demand centers.

Satellite LNG (Liquefied Natural Gas) systems:

- Smaller storage vessels located closer to demand centers.
- LNG stored at minus 260 Fahrenheit; approximate 55,000 therm limit
- Propane tank farms can be larger. Such facilities can serve a bridging role to delay the need for distribution system reinforcement.

What does a Linear Programming Model Do?

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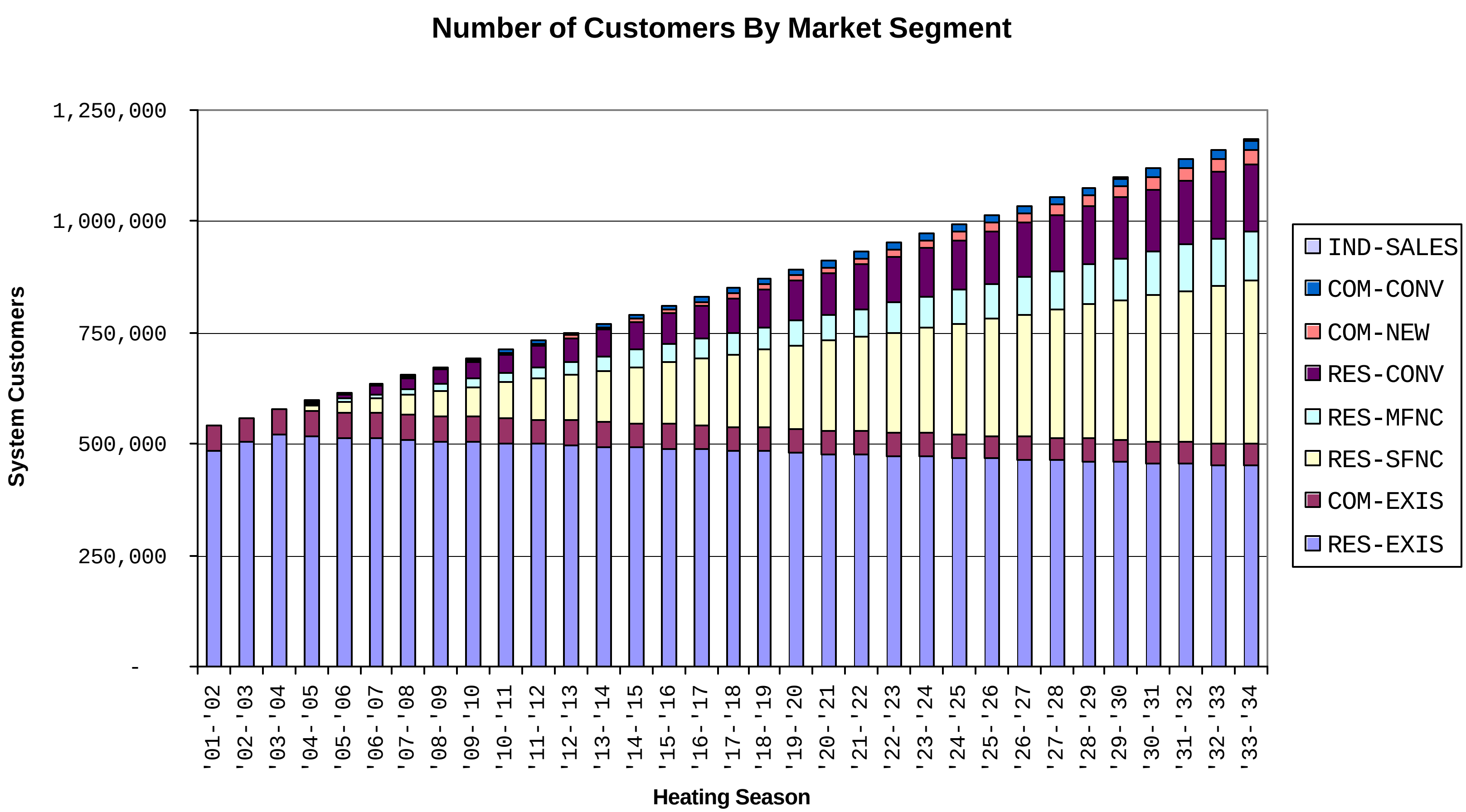
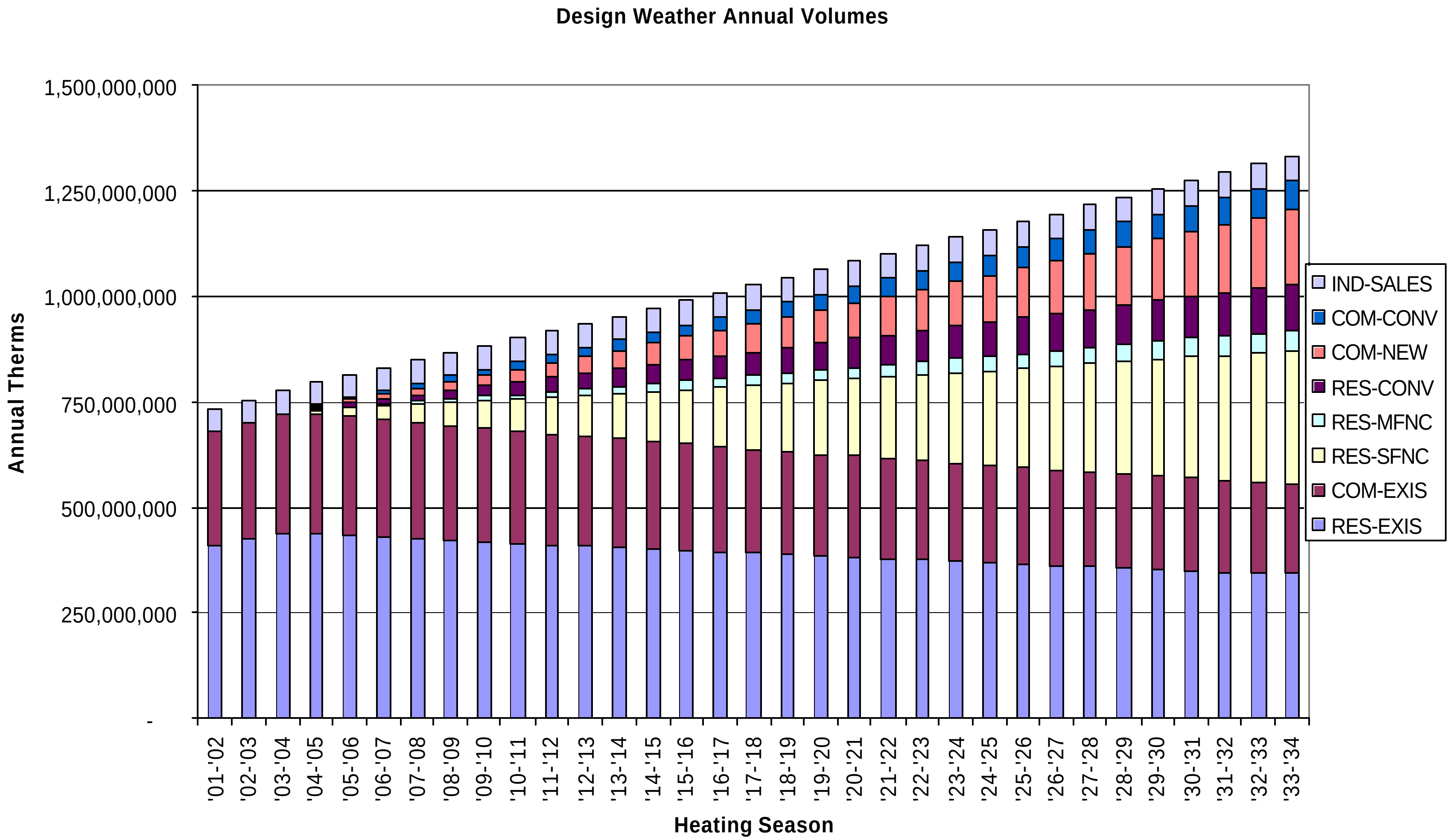
- Minimizes Net Present Value of incremental capacity cost subject to the constraint that all firm gas demands are met.
- No curtailment or gas outages are allowed due to inadequate gas supply capacity.

  It finds the least cost solution by systematically comparing every possible solution
- The LP model <u>does not</u> consider rate design, retail pricing strategies, and switching loads to interruptible service.

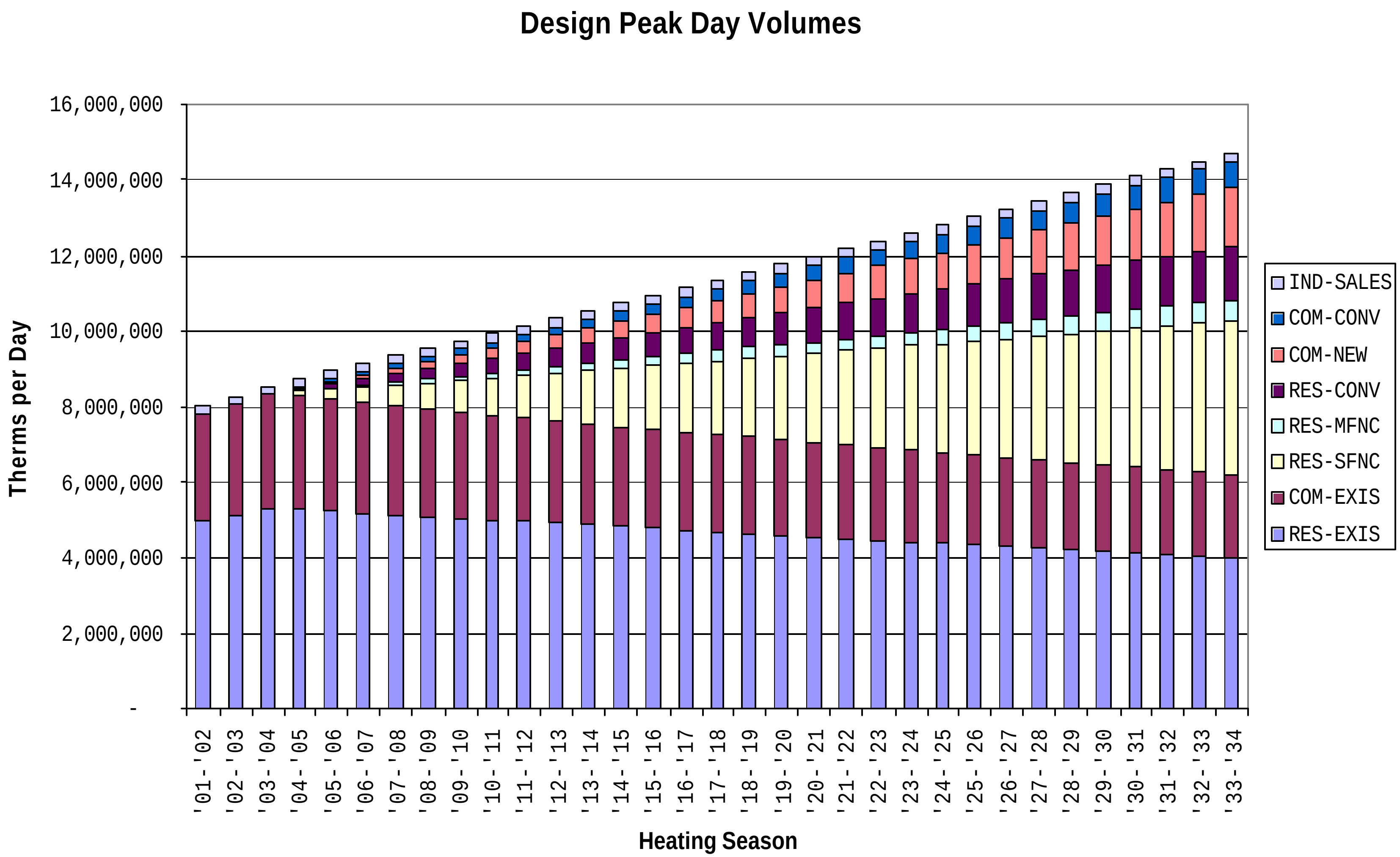
Demand Forecast Detail



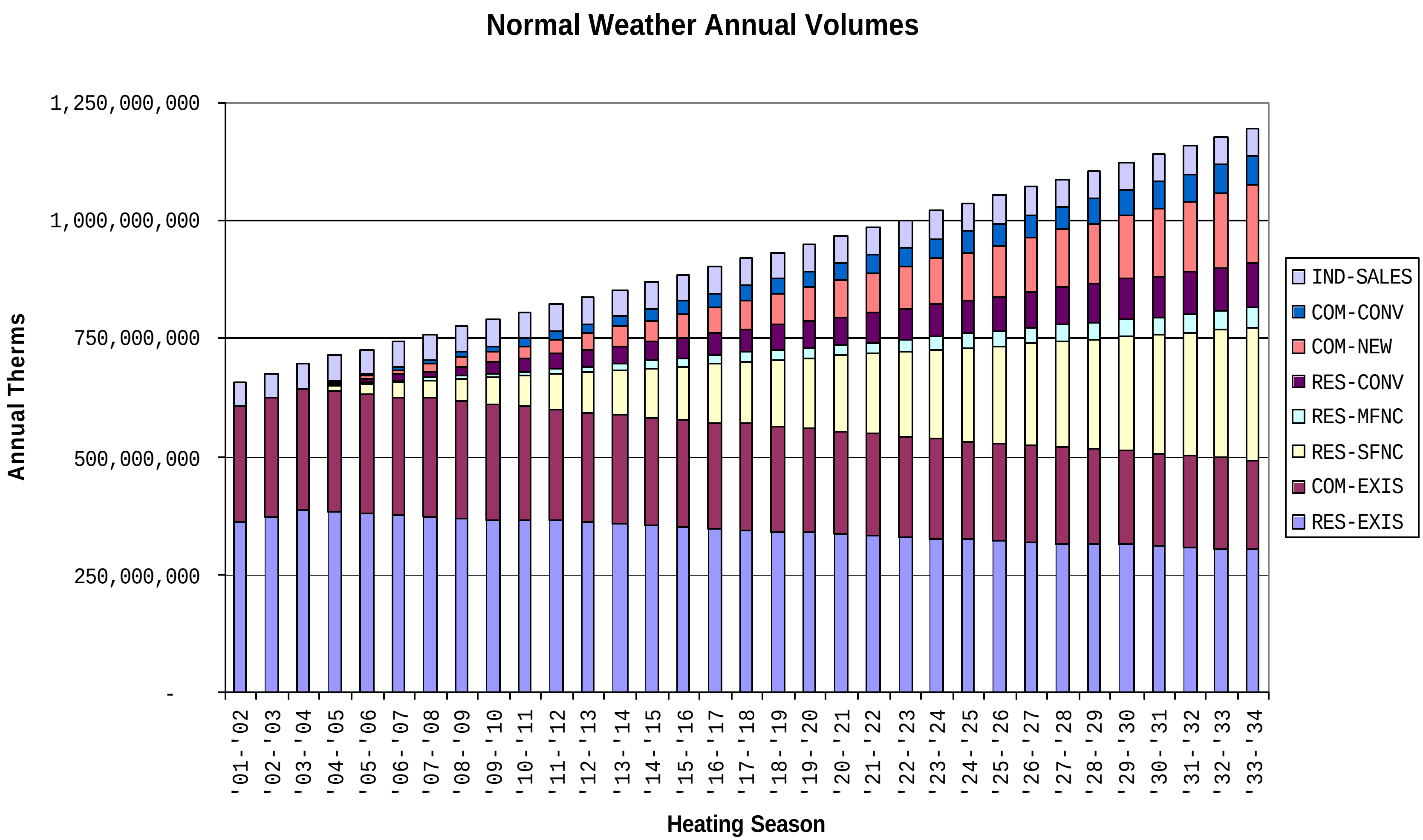
Demand Forecast Detail



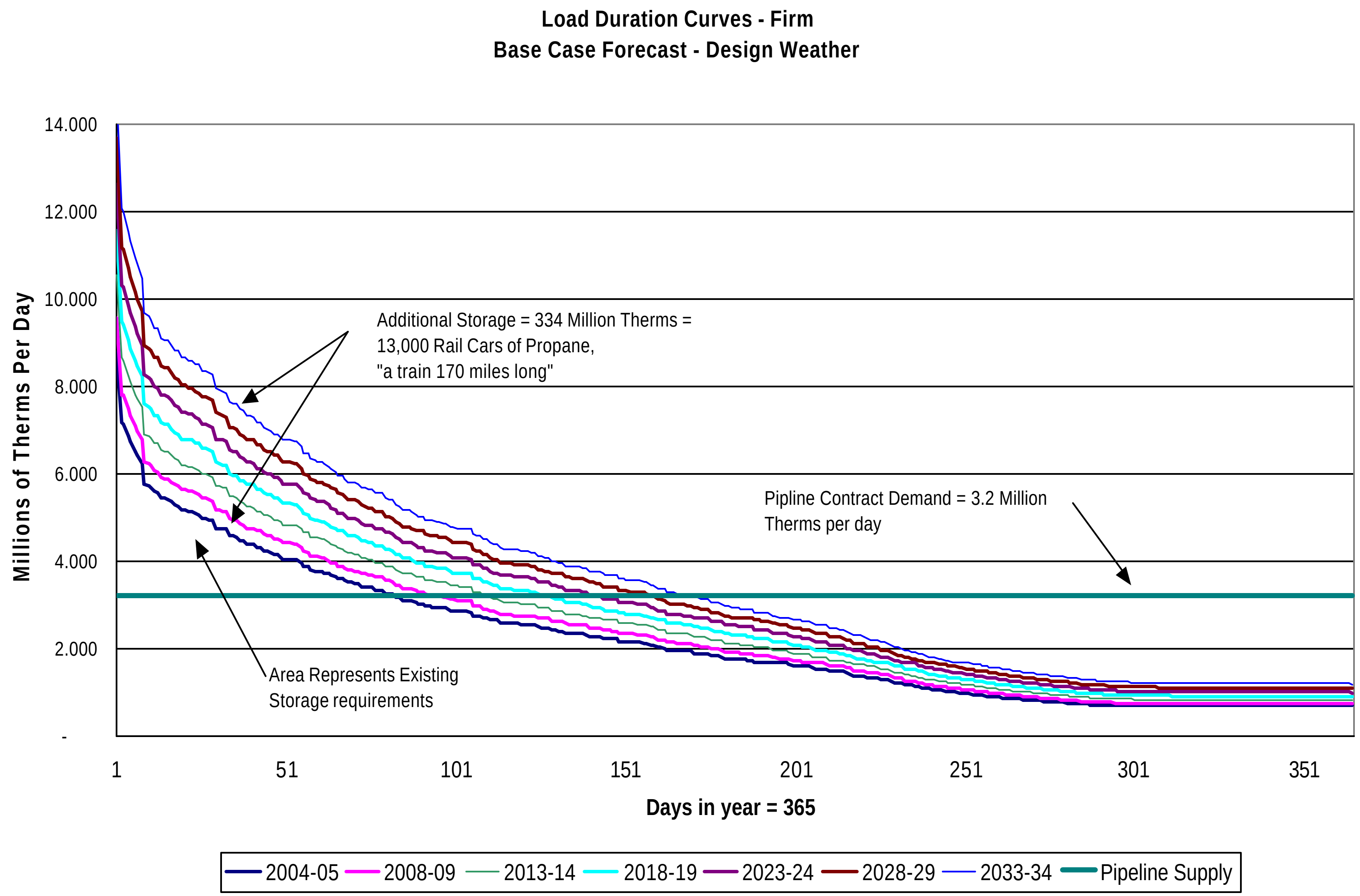
Demand Forecast Detail



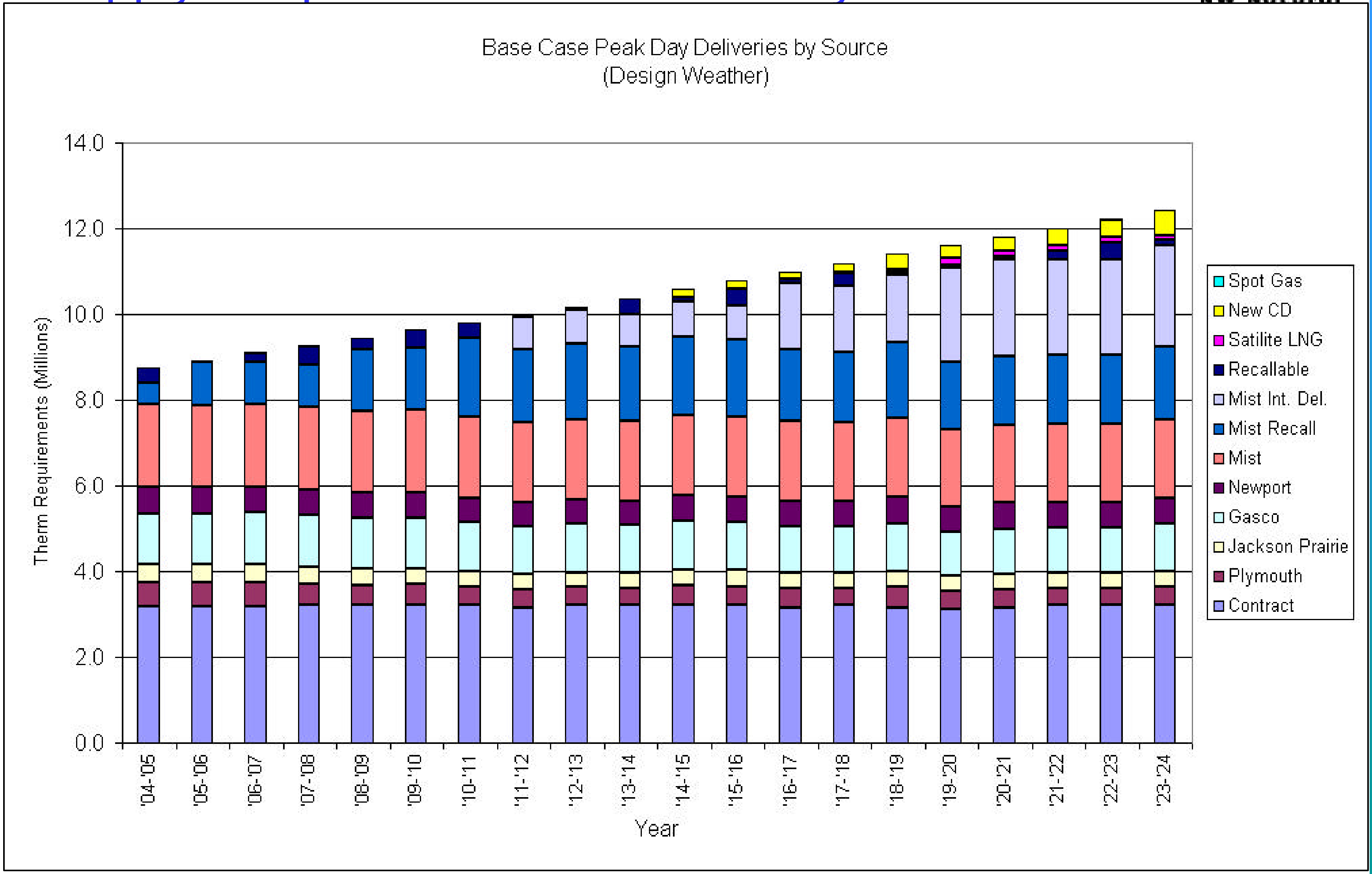
Demand Forecast Detail



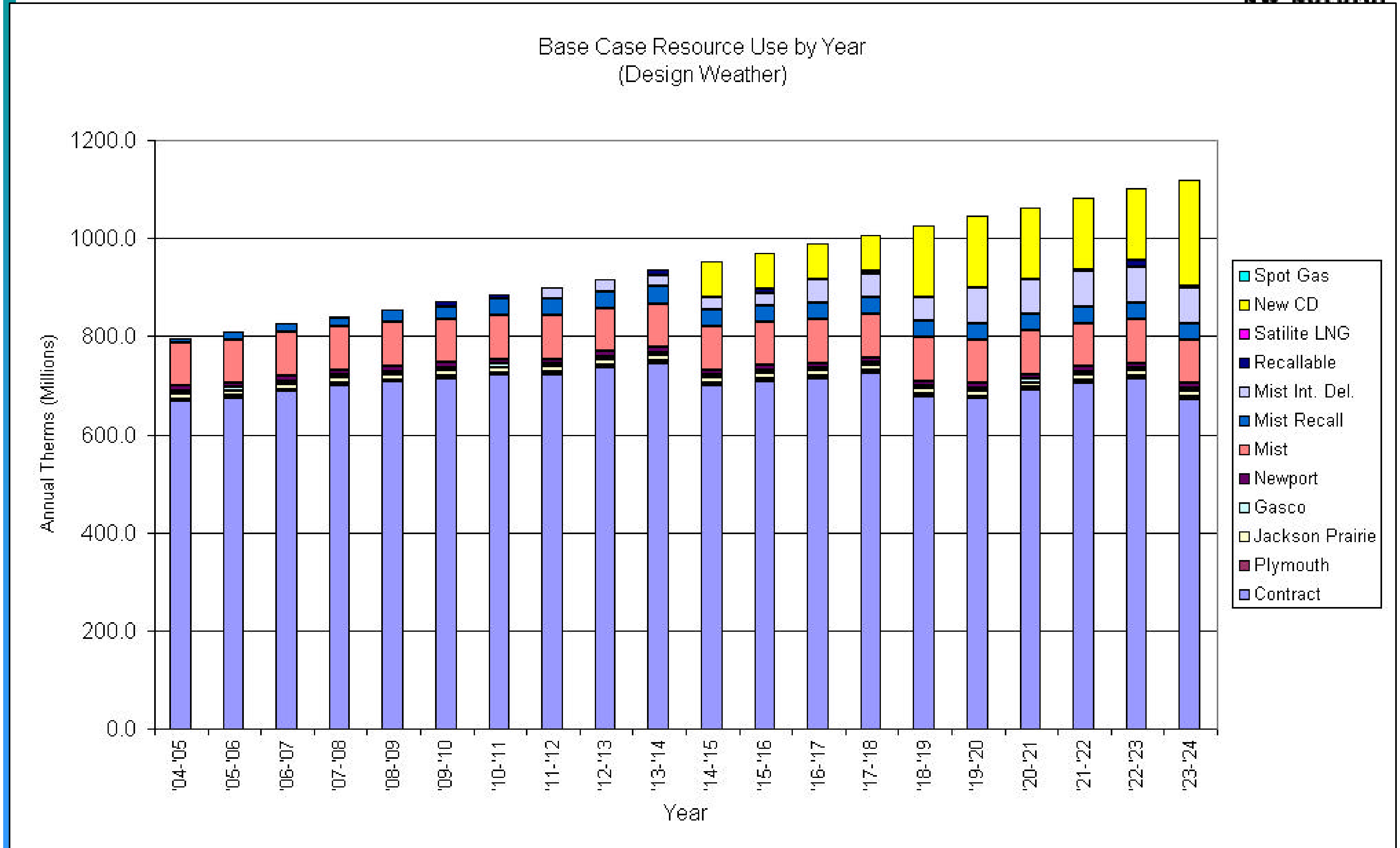
Load Duration Curves – Firm Customers



Supply Response Detail – Peak Day



Supply Response Detail – Design Winter



Glossary of Supply-Side Resource Options

(In reverse order of the legend in the previous two slides)

Contract represents the Maximum Daily Delivery Obligation of pipelines currently under contract. It is also referred to a Contract Demand (CD). This capacity is priced at vintage rates and reflects the cost of old plant at depreciated cost.

Plymouth represents an existing Liquefied Natural Gas (LNG) storage facility at Plymouth WA and the associated pipeline capacity to move gas into the company's service area.

Jackson Prairie represents the company's contract for underground storage services and associated pipeline capacity in a facility located near Centralia WA.

Gasco is a company owned LNG storage facility located at Portland (Linton) OR.

Newport is an LNG storage facility located at Newport OR

Mist represents the existing underground storage capacity and associated infrastructure currently in service to the company's core market customers. It is located within the company's service area at Mist OR (Northwest of Portland).

Mist Recall represents underground storage capacity currently in service to the interstate market, but capacity that can be recalled into core market service. Hence, core market customers acquire these proven storage services without technical risk and at partially depreciated cost. Mist Recall is the lowest cost source of additional peaking capability and storage inventory.

Glossary of Supply-Side Resource Options
(continued)

Mist Int. Del. represents the development of new deliverability at Mist that integrates both additional deliverability and additional annual storage capacity. It involves the development of new un-tested reservoirs and related infrastructure for the interstate-storage-service market, and the subsequent movement of these resources into core market service.

Recallable represents the periodic exercise of contractual rights to capacity temporarily released by other parties during severe cold weather episodes. Typically, entities providing released pipeline capacity allow the company to use their capacity while they switch to an alternative fuel such as oil.

Satellite LNG involves investment in small-scale (sometimes portable) storage tanks for LNG and the necessary associated vaporization capability. Such facilities can serve a “bridging” role by delaying investments in other more permanent sources of peaking capacity.

Glossary of Supply-Side Resource Options (continued)

New CD represents additions to pipeline capacity contracts. The first CD choice occurs in the 2014-15 heating season and is driven by the need for working gas rather than a need for peak day deliverability.

Spot Gas can be interpreted in many ways. It is priced at $100 per therm, a level about 200 times higher than today's wholesale cost of gas. It is simply available anywhere gas is needed without using any particular delivery system. It can also be interpreted as the cost of curtailment or value of reliability. The model chooses very little of this resource. It can also be thought of as a "slack variable" that permits solutions to a system of simultaneous equations.

Energy Efficiency (conservation) Incentives

NW Natural

Decoupling: A mechanism that decouples sales levels (revenues) from company profit levels

What we have in Oregon: Partial Decoupling that helps to insulate earnings levels from customer behavior changes brought about by:

Price level changes

Conservation programs

Appeals for reduced energy use during "energy crises"

Added appliances that increase sales levels

Deteriorating or improving economic conditions affecting customer gas use

Decoupling eliminates the disincentive to pursue Energy Efficiency

Decoupling allows the company to encourage other entities to promote energy efficiency in the most cost-effective manner possible

Public Purpose Funding and the Energy Trust of Oregon (ETO)

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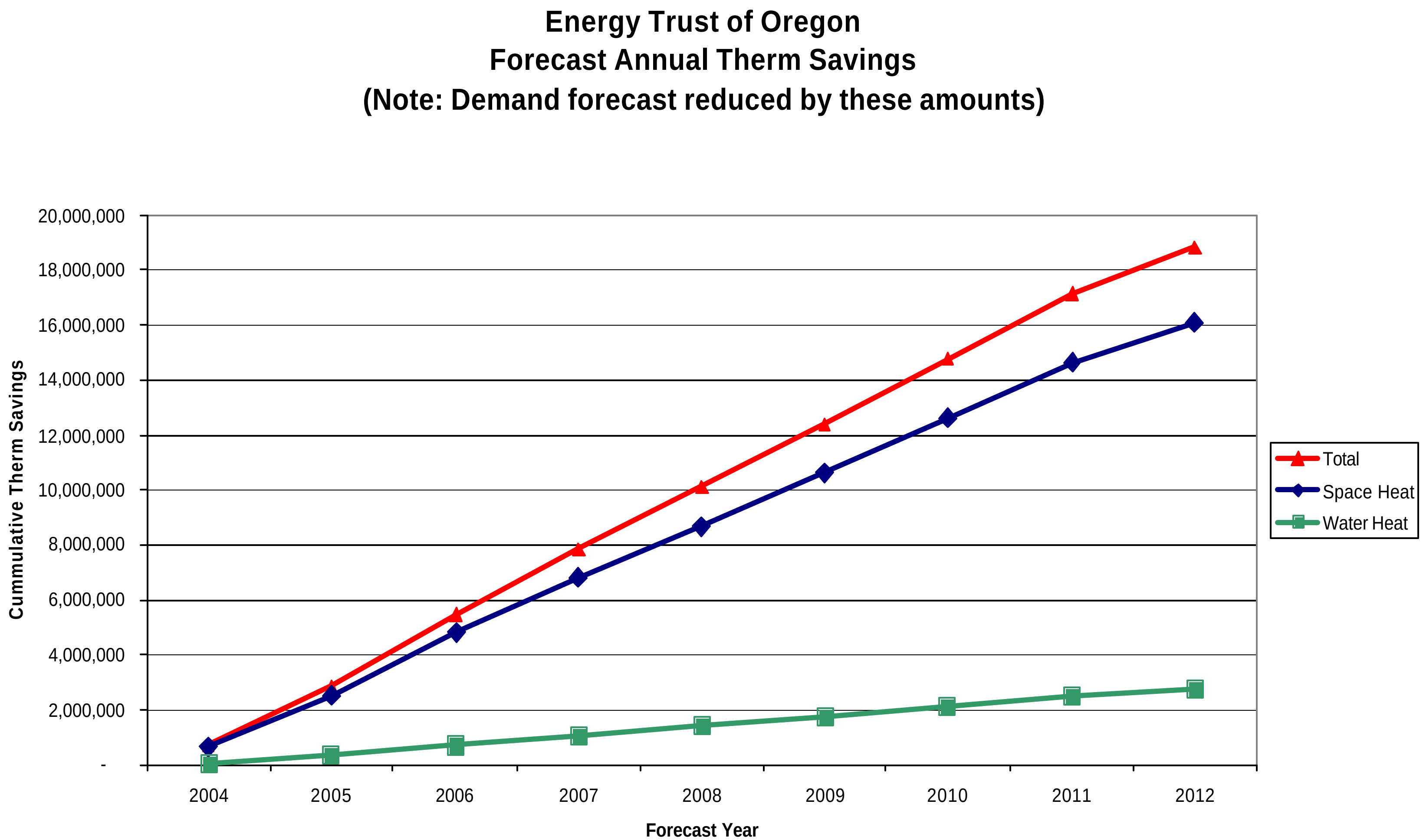
- We surrendered our existing Energy Efficiency (EE) programs to a new Oregon entity primarily tasked with EE acquisitions
- Direct company funding for EE programs ended although we continue to administer low-income weatherization programs
- Despite our best efforts, many of our past EE efforts were not cost effective
- New funding levels for EE are now much higher than before (moved from $1.7 million to approximately $8.5 million)
- We work with the ETO and encourage their success in implementing conservation programs

Expected ETO Funding Results



System Benefits of Underground Storage Development -- Displacement of Pipeline Deliveries

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- Direct service to growth in Southwest Portland Metropolitan Area
- Flexibility for increased Williams Pipeline deliveries North of Molalla to Washington
- Augment gas flowing South on Williams Pipeline from Molalla -- to Eugene
- Augment gas flowing to the east toward Estacada

Preliminary Conclusions

- Underground storage best meets growing peak-day requirements and annual working gas requirements
- Major investments in distribution system infrastructure are not required during this planning cycle
- Current Interstate Pipeline capacity appears to be adequate but opportunities for strategic acquisitions will be evaluated when opportunities present themselves
- NWN does not plan to launch new DSM initiatives but will continue to support energy efficiency through the Energy Trust of Oregon (ETO) and weatherization programs in Washington

Conclusions (continued)

We look forward to the Remaining steps in the Plan review process

COMMENTS -- 2004 IRP

NW Natural

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Optional:

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