FINAL MODELING RESULTS

Linear Programming Optimization Model

The Company uses a computer-based linear-programming optimization model to evaluate both supply-side and demand-side resources. Ventyx maintains this software product and markets it under the name of “SENDOUT.” Ventyx is owned by ABB, a global power and automation technology group headquartered in Zurich, Switzerland with approximately 132,000 employees. Roughly 100 utilities use SENDOUT for gas supply planning and portfolio optimization.

SENDOUT has the capability of performing Monte Carlo simulations thereby facilitating risk analysis. The Monte Carlo method utilizes repeated random sampling to generate probabilistic results. It is best applied where relative frequency distributions of key variables can be developed or where draws can be made from historic data. Because of the need for numerous random draws, the availability of high-speed computer technology helps facilitate this process.

The Company is using Version 14.3 of the SENDOUT modeling software. This version was recoded to keep the grid manager attached to the SENDOUT database. In performing gas supply modeling, the Company works closely with consultants from Ventyx. The Ventyx consultants are very familiar with the gas-supply modeling conceptual approach of the Company and they are comfortable with how the Company utilizes and configures the SENDOUT model.

Constraints and Linear Programming

While the concepts of linear programming date back to the early 19th century, it was not until the middle of the 20th century that this approach began to be more widely accepted as a method for achieving optimal solutions in practical applications. In summary, linear programming problems involve the optimization of a linear objective function subject to linear constraints.

Constraints are necessary in determining a maximum or minimum solution. Constraints must be linear functions that represent either equalities or inequalities. An example of an inequality constraint in the natural gas business would be the quantity of natural gas that is physically transported over a certain segment of an interstate pipeline must be “less than or equal to” a certain level of transportation previously contracted for with that pipeline company. Another example of an inequality constraint would be the forecast production available from a group of cost-of-service wells. The amount this resource can be taken can never exceed the forecast maximum level available as production naturally declines over time. All resources are defined by constraints.

Constraints must accurately reflect the problem being solved. The arbitrary removal of required constraints results in an unacceptable solution. For example, if the Company removed the constraint on how quickly it filled Clay Basin, the model would assume that it could be done instantaneously, resulting in an unrealistic solution. The removal of all constraints in a linear programming problem would result in no solution ever being able to be reached. The Company periodically reevaluates the constraints in its SENDOUT model to determine if they accurately reflect the realities of the problem being solved.

Model Improvements

The Company made two modifications to the SENDOUT model for the 2018-2019 IRP. First, the discount rate used in the model was adjusted to 4.09% to reflect the Carrying Charge stated in the Tariff. Second, due to SENDOUT software limitations, the runtime for the RFP analysis was limited to 15 years as opposed to 31 years in the past. The primary Monte Carlo analysis for the IRP was still run with a 31 year time frame.

Monte Carlo Method

To have a meaningful Monte Carlo simulation, it is important to have a sufficient number of draws (typically hundreds). Each draw consists of one deterministic linear programming computer run. With the complexity of the Company's modeling approach, one simulation can take as long as several days to run. The base Monte Carlo simulation developed by the Company this year utilized 1,405 draws.

When the developers of SENDOUT incorporated the Monte Carlo methodology, they limited the number of variables for which stochastic analysis can be applied to avoid excessive computer run times. The two variables determined necessary are price and weather (within SENDOUT, demand is modeled as a function of weather). No other variables have a more profound impact on the cost minimization problem being solved by SENDOUT.

The output reports generated from the SENDOUT modeling results consist primarily of data and graphs. Most of the graphs are frequency distribution profiles from a Monte Carlo simulation. Many of the numerical-data reports show probability distributions for key variables in a simulation run. The heading "max" in these reports refers to the value of the draw in a simulation with the highest quantity. The heading "min" refers to the value of the draw in a simulation with the lowest quantity. The heading "med" refers to the median draw (or the draw in the middle of all draws).

The Company believes that the mean and median values are good indicators of likely occurrence, given the underlying assumptions in a simulation. Many exhibits in this report also include a normal case number to show how the normal case compares to the mean and median. The Company will discuss the normal case in more detail later in this section. Also in these reports are the headings "p95," "p90," "p10," and "p5." The label "p95" on report means, based on input assumptions, that a 95% confidence exists that the resulting variable will be less than or equal to that number. Likewise, a "p10" number suggests that there is a 10% likelihood that a variable will be less than or equal to that number. These statistics, and/or the shape of a frequency curve, define the range and likelihood of potential outcomes.

Natural Gas Prices

It is extremely difficult to accurately model future natural gas prices. Most of the Company's natural gas purchases are tied contractually to one or more of four price indices. Two of those indices are published first-of-month prices for deliveries to the interstate pipeline systems of Kern River and Northwest Pipeline. The remaining are two published daily indices for Kern River and one basket containing a combination of two additional Kern River indices.

To develop a future probability distribution, the Company assembles historical data and determines the means and standard deviations associated with each price index. The Company then uses the average of two price forecasts developed by PIRA (67 months) and CERA (271 months) as the basis for projecting the stochastic modeling inputs. The Company adjusts forecasted standard deviations pro rata based on the historical prices to more accurately mirror reality. Exhibits 13.01 through 13.36 show, for the first model year, the resulting monthly price distribution curves for the first-of-month prices and the daily prices for each of the price indices used in the base simulation.

Weather and Demand

Weather-induced demand is the single most unpredictable variable in natural gas resource modeling. The Company provides 89 years of weather data to the SENDOUT model. When forecasting future demands, heating degree days are stochastic with a mean and standard deviation by month. The Company uses this number, along with usage-per-customer-per-degree-day and the number of customers, to calculate the customer demand profile used by the model.

The stochastic nature of the heating-degree-days creates a normal plot for degree days based on the 1,405 draws. For each month of simulation, the model randomly selects a monthly-degree-day standard-deviation multiplier to create a draw-specific monthly-degree-day total. It scans through 89 years of monthly data to find the closest matching month. Then the model allocates daily degree-day values according to the degree-days in this historic month pattern. Exhibits 13.37 through 13.49 show the annual and the monthly demand distribution curve for the first year of the base simulation. Exhibit 13.50 shows the annual heating-degree-day distribution.

Design-Peak Day and Baseload Purchase Contracts

Another important consideration in the modeling process is the need to have adequate resources sufficient to meet a Design-Peak Day. The sales-demand Design-Peak Day for the 2018-2019 heating season is approximately 1.330 MMDth per day at the city gates. The most likely day for a Design-Peak Day to occur is on January 2, although, the probability of a Design-Peak Day occurring on any day between mid-December and mid-February is relatively the same.

Selecting a draw from a Monte Carlo simulation that utilizes, on the maximum demand day, a level of resources approximately equaling the Design-Peak Day has proven to be problematic in that it results in the SENDOUT model selecting too much baseload purchased gas for a typical weather year. The draws which have a Design-Peak-Day occurrence also tend to be much colder than normal throughout the entire year. The solution to this dilemma is to perform a statistical clustering analysis of all the Monte Carlo draws for first-year Design-Peak-Day demand versus the median level of first-year annual demand.[72] The result of this clustering exercise is a scatter plot that shows groups of draws. These cluster points or groups represent draws that are most closely alike in terms of Design-Peak-Day requirements and annual demand. The Company then chooses a cluster point that it believes will meet annual demand without falling short on Design-Peak Day.

The Company then executes a series of deterministic SENDOUT scenarios, removing the unused RFP packages, and leaving those "cluster point" packages. One of the purposes of these runs is to verify that adequate purchased gas resources, at the lowest cost, will be available in the event that a Design-Peak Day were to occur. The optimizing nature of the SENDOUT model helps to make this happen. This year, of the 1,250 draws generated in this process, three draws would exceed the Design-Peak-Day requirement of 1.330 MMDth. In other words, this scenario has enough resources to meet a Design-Peak-Day event. Most of the seasonal baseload purchased-gas resources are committed prior to the beginning of the IRP year. Storage, daily spot gas, and cost-of-service gas supply do not need to be committed to before the IRP year begins. This modeling approach also lends itself to performing operational analysis during the year as natural gas prices change.

Exhibit 13.51 shows the resources utilized to meet the Design-Peak Day. Exhibit 13.52 shows the firm-peak-day demand distribution for the base simulation for the first plan year. As expected, the Design-Peak Day for the Company is in the upper portion of the curve.

Normal Temperature Case

In this document, the normal temperature scenario can be seen in Exhibits 13.83 through 13.88. These show additional planning detail for the first two years of the normal case. The Company lists monthly data for each category of cost-of-service gas and each purchase-gas package. The Company also includes planned injections and withdrawals for each of the storage facilities currently under contract. Although no actual gas-supply year will ever perfectly mirror the plan, these exhibits are among the most useful products of the IRP process. They are used extensively in making monthly and day-to-day nomination decisions.

Purchased Gas Resources

Exhibits 13.53 through 13.64 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 13.65 shows the annual distribution from the simulation. Exhibit 13.66 shows the numerical monthly data with confidence limits. Gas purchased for the first plan year under the normal case is approximately 49.7 MMDth. The Company is confident that, for a colder-than-normal year,

[72] See the cluster analysis discussion in the Modeling Issues subsection of the Purchased Gas section of this report.

sufficient purchased-gas resources will be available in the market. Likewise, the Company is confident that in the event of a warmer-than-normal year, it has not contracted for too much gas.

Cost-of-Service Gas

Another important output from the SENDOUT modeling exercise each year is a determination of the level of cost-of-service gas to be produced during the upcoming gas-supply year. Exhibits 13.67 through 13.78 show the distributions for cost-of-service gas for each month of the first plan year from the base simulation. Exhibit 13.79 shows the annual distribution from the simulation. Exhibit 13.80 shows the numerical monthly data with confidence limits. Cost-of-service production for the first plan year from the normal case is approximately 70.6 MMDth.

First-Year and Total System Costs

The linear-programming objective function for the SENDOUT model is the minimization of variable cost. A distribution curve for first-year total cost from the base simulation is shown in Exhibit 13.81. The first year total cost from the normal case is approximately $564 million. A similar curve for the total 31-year modeling time horizon is shown in Exhibit 13.82. The normal case cost for this time period is approximately $15.3 billion.

Gas Supply/Demand Balance

Exhibits 13.89 and 13.90 show monthly natural gas supply and demand broken out by geographical area, residential, commercial and the non-GS categories of commercial, industrial and electric generation.

This report is available in SENDOUT and is titled “Required vs. Supply.” The data in these exhibits represent the normal case. The Company slightly adapted the SENDOUT report to show geographical areas and lost-and-unaccounted-for gas. Because the Company measures demand at the customer meter and modeling occurs at the city gate, in years past the Company grossed-up demand by the estimated lost-and-unaccounted-for volume to model natural gas demand at the city gate.[73] The Company models lost-and-unaccounted-for gas as a percent of the other demand classes and lists it as its own specific demand class.

Exhibit 13.89 of the report shows the requirements of the system. Those are specifically demand, fuel consumed, and storage injection. This results in a total requirement of 136 MMDth for the normal case. Exhibit 13.90 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the 136 MMDth demand for the normal case.

[73] Also included are compressor fuel, Company use, and gas loss due to tear outs.

Shut-in Scenario Analysis

The Utah Commission, in its Report and Order issued October 22, 2013 concerning the Company's 2013 IRP, required the Company to provide a scenario analysis for future IRPs that includes varying percentages of cost-of-service gas with varying levels of the Company demand (e.g., low, normal and high).[74]

The tables below illustrate different scenarios that may occur with differing levels of cost-of-service gas and demand. Table 13.1 shows the estimated annual volume of cost-of-service gas that would be shut in under different scenarios. Table 13.2 shows the anticipated total annual costs under different scenarios. The cost differences are, in part, a result of estimated shut-in costs when cost-of-service gas exceeds demand as well as the cost of having to replace cost-of-service gas (with purchased gas) when demand exceeds the amount of cost-of-service gas available.

Table 13.1: Annual Shut-In Production

		Demand (Thousands of Dekatherms)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	196.0	0.0	0.0
	IRP Forecast	2,117.2	661.2	433.5
	High 10%	5,377.7	3,309.5	3,722.0

Table 13.2: Total Annual Production Costs

		Demand (Millions of Dollars)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	$504.3	$567.3	$633.2
	IRP Forecast	$502.3	$564.8	$631.6
	High 10%	$504.4	$564.9	$632.5

[74] In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2013 to May 31, 2014, The Public Service Commission of Utah, Report and Order, Docket No. 13-057-04, Issued: October 22, 2013.