COST-OF-SERVICE GAS

Cost-of-Service Modeling Factors

The Wexpro Agreement, signed in 1981, defines the relationship between Dominion Energy Wexpro and the Company. Under this relationship, Dominion Energy Wexpro manages and develops natural gas reserves within a limited and previously established group of properties. Production from these reserves is delivered to the Company at cost-of-service, which historically has been lower-priced than market-based sources. Since its inception, the Company's customers have received a net benefit from natural gas produced pursuant to the Wexpro Agreement.[63] In recent years, natural gas supplies provided pursuant to the Wexpro Agreement have exceeded one half of the total annual supplies required to meet the needs of Company customers.

During 2013, both the Utah and the Wyoming Commissions approved the Wexpro II Agreement. This agreement was designed to continue the delivery of cost-of-service natural-gas supplies to the customers of the Company through the acquisition of oil and gas properties or undeveloped leases.

In January of 2014, the Utah and Wyoming Commissions approved the Trail Unit Acquisition as a Wexpro II Property. As part of this approval, Dominion Energy Wexpro must manage cost-of-service production to less than 65% of the forecasted demand for the Company's sales customers each IRP year. In calculating the production percentage, pursuant to the Trail Stipulation, the total wellhead volume of cost-of-service production received as part of the Wexpro I and Wexpro II Agreements will be divided by the total forecasted demand for the Company's sales customers as provided in each year's IRP (see Exhibit 3.10). Dominion Energy Wexpro may also sell cost-of-service production in order to manage to the 65% level. Any production sold will be credited to the Company at the greater of the sales price or the cost-of-service price.

In November of 2015 the Utah and Wyoming Commissions approved the Canyon Creek Unit Acquisition as a Wexpro II Property. As part of this approval, the Company, Dominion Energy Wexpro, the Division, the Office, and the Wyoming OCA, submitted the Canyon Creek Stipulation to the Wyoming and Utah Commissions in their respective dockets. On November 17, 2015, the Utah Commission approved the Canyon Creek Stipulation, and on November 24, 2015 the Wyoming Commission issued its approval of the Stipulation.

[63] "The Wexpro Stipulation and Agreement," Executed October 14, 1981, Approved October 28, 1981, by Public Service Commission of Wyoming and December 31, 1981, by Public Service Commission of Utah.

In addition to adding the Canyon Creek acquisition as a cost-of-service property under the Wexpro II Agreement, the Canyon Creek Stipulation included certain requirements as follows:

- Dominion Energy Wexpro will design its annual drilling program or drilling programs that are more frequent than the annual cycle to provide cost-of-service production that is, at the time Dominion Energy Wexpro incurs an obligation in connection with a drilling program, on average, at or below the 5-Year Forward Curve price that was agreed to in the Trail Settlement Stipulation.

- The rate of return on post-2015 Wexpro I and Wexpro II development drilling, or any other capital investment, will be the Commission Allowed Rate of Return as defined in the Wexpro II Agreement (currently 7.64%). The pre-2016 investment base and returns will not be affected.

- Dominion Energy Wexpro will reduce the cost-of-service gas supply to the Company from 65% of annual demand to 55% by the 2020 IRP Year.

- Post-2015 dry-hole and non-commercial well costs will be expensed and shared on a 50/50 basis between utility customers and Wexpro.

- When the annual weighted average price of cost-of-service gas produced under both Wexpro agreements is less than the current market price, then the annual savings on post-2015 development will be shared on a 50/50 basis between utility customers and Dominion Energy Wexpro. When shared savings occurs, Wexpro's return will be capped at the Base Rate of Return + 8%.

During January of 2017, the Company filed, with regulatory agencies, its third application for approval of properties under the Wexpro II Agreement, as discussed in the Introduction and Background Section of this report. The Company filed for approval of the Vermillion Acquisition as a Wexpro II property. The Vermillion Acquisition included natural gas producing properties within the Vermillion Basin in the Kinney, Trail, Whiskey Canyon, and Canyon Creek Units. Also included were certain Canyon Creek overriding royalties. The Trail and Kinney Unit properties in the Vermillion Acquisition are within the Wexpro I Development Drilling Area and therefore the Company was required to apply for Utah and Wyoming Commission approval for inclusion under the Wexpro II Agreement. The Wexpro II Agreement also allows for properties outside the Wexpro I Development Drilling Area to be submitted for inclusion under Wexpro II as was the case for the Whiskey Canyon and Canyon Creek properties in the Vermillion Acquisition.

During March of 2017, the Utah and Wyoming Commissions approved the Vermillion Acquisition as a Wexpro II property. As the cost-of service gas produced from existing Kinney wells currently exceeded market prices, the Stipulation provided for the withdrawal of the Kinney Unit property from current consideration under Wexpro II. The Stipulation contained a clause allowing the Kinney property to be resubmitted for regulatory approval in the future.

During calendar year 2016, Dominion Energy Wexpro produced 66.9 MMDth of cost-of-service supplies measured at the wellhead, down from the 69.5 MMDth level produced during calendar year 2015. As development drilling continues to occur, Dominion Energy Wexpro anticipates that there will be many more years of production from these sources, due in part to technological improvements in drilling and production methods.

From calendar year 2015 to 2016, the total costs, net of credits and overriding royalties, for cost-of-service production declined by approximately 2.8% (the second consecutive year of declining net costs). This decrease was caused primarily by two cost components. First, the development-gas cost-of-service component decreased by approximately 8.3%. Second, because market prices had declined in 2016 as compared to 2015, royalties paid to other parties decreased by approximately 21.4%. More information on Dominion Energy Wexpro's planned development-drilling programs is contained in the Future Resources discussion later in this section.

One of the important results of the SENDOUT modeling process is a determination of the appropriate production profiles for the cost-of-service gas. This year, the Company modeled 113 categories of cost-of-service production. Last year, it modeled 103 categories. Both years, the Company used a modeling time horizon of 31 years. A relatively long time-horizon better reflects the fact that cost-of-service gas is a long-term resource.

The Company created these categories of cost-of-service gas to naturally group wells which have common attributes including factors such as geography, economics, and operational constraints. A large amount of data must be compiled to provide the inputs to the SENDOUT modeling process. The Company has relied on the expertise of Dominion Energy Wexpro personnel in assembling the data elements needed to model each category. Some of those data elements are: reserve estimates, production decline parameters, depreciation, and amortization rates, carrying costs, general and administrative costs, operating and maintenance costs, production taxes, royalties, income taxes, and oil revenue credits. The Final Modeling Results section of this IRP contains the probability curves and median levels of production for cost-of-service gas resulting from the SENDOUT modeling process this year.

As discussed in the Introduction to this report, 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 in future IRPs.[64] The IRPs should contain an analysis consisting of the results from multiple SENDOUT modeling scenarios. These scenarios should include varying percentages of cost-of-service gas with varying levels of Company demand (e.g., low, normal, and high). For each scenario, the Company should provide expected management actions, such as projected well shut-ins. Scenario results should include the impacts of those management actions on overall costs. Appendix A of this report contains the requested scenario analysis.

[64] 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.

Since the late 1990s, the Company has submitted confidential quarterly variance reports to Utah regulatory agencies, as required under the Utah Commission's IRP standards and guidelines. These reports detail the material deviations between planned performance and actual performance of cost-of-service natural gas supplies. Under the 2009 IRP Standards, that process will continue into the future.

There are many reasons the confidential quarterly variance reports often show variance between anticipated volumes and actual production. As part of the IRP modeling process, Dominion Energy Wexpro and the Company are required to anticipate the production capability of approximately 1,749 wells. Some of these wells have not been drilled yet, but are included in the planning process. Forecasting production from existing wells is not a precise science, and forecasting for wells not yet drilled involves even more uncertainty. New wells can be, and occasionally are, dry holes. Production from new wells can vary from non-commercial quantities to levels several times that anticipated during the planning process. Fortunately, non-commercial wells occur very rarely.

Unanticipated delays during the partner approval process can also postpone planned production. Delays during permitting, drilling, and completion can also affect the timing of production volumes. An unexpected archeological find on a drill site can cause extensive delays for all the wells planned for the site, or can cause the wells not to be drilled at all. Even small delays can cause schedules to conflict with environmental windows for the migration, mating, and/or nesting of local species, resulting in greater delays. Pad drilling, with all its inherent cost efficiencies can also create delays. Since all the wells on a pad are typically connected to a single gathering system, any delay in one well affects the production timing of all the pad wells.

For existing wells, a multiplicity of geotechnical factors can affect production levels. Although reservoir engineers are skilled in the utilization of sophisticated techniques to forecast future production decline rates, precisely predicting the performance of reservoirs many thousands of feet deep is complex and uncertain. The fact that the pressures of the connected gathering lines are constantly changing due to fluctuating supplies into, and demands from, the local gathering system further complicates the production process (a phenomenon often totally out of the control of the producers). New wells drilled by any party typically come in at very high pressures and, in the short term, can "pressure-off" old wells temporarily reducing existing production levels from a field. While compression can remedy such problems, those costs must be factored into the overall economics of the production stream. Also, the design and construction of compression facilities takes additional time to complete. There are many reasons for variances between planned and actual cost-of-service gas volumes.

Producer Imbalances

In most cost-of-service wells, there are multiple working interest partners. Each of these partners generally has the right to nominate its legal entitlements from a well subject to restrictions as defined in the operating agreement and/or gas balancing agreement governing that well. As the individual owners in a well each nominate supplies to meet their various marketing commitments, imbalances between the various owners are created. Imbalances are a natural occurrence in wells with multiple working interest owners. There are no fields or wells with multiple owners having individual marketing arrangements where an imbalance does not exist. No individual working interest owner can control, in the short term, the level of producer imbalances associated with a well because it does not have control over the volumes that the other working interest owners are nominating.

Anytime allocated wellhead volumes differ from legal entitlements for any one party, an imbalance is created for all the parties in the well. The fact that it is not uncommon for the market of a working interest owner to be lost unexpectedly, either in part or in full, for a variety of reasons, further complicates matters. This can happen without the knowledge of the other parties for a significant period of time, and will contribute to an imbalance.

For some wells with multiple working interest owners, contract-based producer-balancing provisions exist. These provisions generally allow for parties that are under-produced to nominate recoupment volumes from parties that are over-produced. Given the time lag in the accounting flow of imbalance information, delays of several months can occur. The process becomes more complicated because several weeks' advance notice is typically necessary before imbalance recoupment nominations can occur.

Over the past year, producer-imbalance recoupment has taken place in several areas where the Company is entitled to cost-of-service supplies. Exhibit 6.1 shows the monthly volumes nominated in these areas for recoupment during calendar year 2016 and for the first two months of 2017. Since January of 2016, the Company has been taking recoupment in the Moxa Arch area. The Company also took recoupment from the Church Buttes field for the month of March 2016, and from one well in the Butcherknife area from November 2016 through January of 2017.

As can be seen in Exhibit 6.1, other parties have been recouping gas from the Company. A working interest partner in the Hiawatha Deep wells has been recouping gas from the Company since March of 2015. In the Moxa Arch field, recoupment from the Company has been occurring for several years. A working interest partner recouped gas from the Company in the Dry Piney field during November and December of 2016.

As of December 31, 2015, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of a negative 0.1 Bcf.[65] By way of comparison, the total net producer imbalance level for December 31, 2016 was a negative 0.3 Bcf. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In a recent audit report, the Hydrocarbon Monitor concluded that the total producer imbalance levels were reasonable.[66]

[65] A positive imbalance means volumes are owed to other parties.

[66] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, April 2017.

Future Resources

The current market price of natural gas coupled with future price expectations directly drives the level of drilling in the U.S. Multiple other factors also play into the drilling decision. For example, it may make sense to drill when prices are down because drilling costs are generally lower. By the time a well is drilled and turned to production, prices may have rebounded.

In many situations, lease obligations and drilling permits dictate that leases must be developed within a specified period of time. Lease obligations may require that a property be developed within 5-10 years or the leases may be lost. Drilling permits typically expire after 2 years. Allowing drilling permits to expire would result in additional costs by requiring the process to start over. These provisions generally prevent exploration and production companies from holding leases indefinitely without creating value for royalty owners. In the current price environment, a substantial portion of drilling in shale-gas plays continues in order to hold leases.

There can be other factors affecting the rate of leasehold development. For example, the Company's customers benefit from the receipt of significant quantities of cost-of-service production from wells in the Pinedale Anticline Project Area (PAPA) in Sublette County, Wyoming. Development in the PAPA is governed by a Record of Decision (ROD), issued by the U.S. Department of Interior, Bureau of Land Management during September of 2008. The ROD was issued in response to certain environmental mitigation measures and operational safeguards proposed by the partners in PAPA.[67]

As a means of minimizing environmental impacts, the Pinedale ROD, in an orderly and systematic way, allows for concentrated development by limiting the number of well pads and requiring the maximum use of existing well pads before constructing new well pads. Operators are required to "stay on a well pad until the well pad is completely drilled out".[68] Drilling is fundamentally sequential with time limitations for development in certain areas.

Dominion Energy Wexpro's focus is to maintain its long-term drilling plans, thereby continuing to benefit the Company's customers. For calendar year 2017, Dominion Energy Wexpro plans on completing to production, approximately 22.3 net wells with a capital budget for those wells of approximately $40 million.[69] Assuming market prices don't deviate dramatically from current expectations for the years 2018 through 2022, the total planned net wells are approximately 30, 21, 32, 19, and 6 respectively, with total annual investments in the range of $9 to $55 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2017 is expected

[67] Record of Decision for the Supplemental Environmental Impact Statement, Pinedale Anticline Oil and Gas Exploration and Development Project, U.S. Department of the Interior, Bureau of Land Management, Cheyenne Wyoming, September 12, 2008.
[68] Ibid., Summary, Page 20.
[69] "Net wells" are the summation of working interests (total and partial ownership).

to focus primarily in the Mesa/Pinedale, Canyon Creek, and Trail areas with lesser activity planned in the Whiskey Canyon and Bruff areas.

Wexpro II drilling plans for 2017 through 2022, broken out from the total net wells stated above, are for approximately 7, 14, 10, 16, 14, and 3 net wells respectively to be drilled with total annual capital costs ranging from approximately $5 million to $23 million.

Plans, forecasts, and budgets for drilling development wells under the Wexpro Agreements are always subject to change. Many factors including economic conditions, ongoing success rates, partner approval, availability of resources (rigs, crews and services), access issues associated with environmentally sensitive areas, re-completion requirements, drainage issues, and demand letters all have an impact on drilling and capital budget projections.

Production Shut Ins

The Company utilizes the SENDOUT model to optimize the use of cost-of-service production. The SENDOUT model will choose to shut in the production when it determines this is the most optimal solution considering gas costs, storage availability, and demand.

The actual volume of shut-in production for 2016 was higher than the forecasted amount as shown in Table 6.1 below. The variance was due to concerns regarding filling Clay Basin ahead of the model forecast. Production from June through August was slightly above forecasted estimates. As a result, the Company chose to increase the amount of shut-in production in August to limit shut-in levels to only lower cost wells. If production continued and temperatures warmed, Clay Basin would have been full ahead of schedule resulting in higher shut-in volumes and therefore higher costs. See Appendix A of the 2016-2017 Questar Gas IRP.

Based on the forecast for production provided by Dominion Energy Wexpro and normal weather, the model determined that there should be no cost-of-service production shut in for June 2017 through October 2017.

Table 6.1 – 2016

	June	**July**	**August**	**September**	**October**	**Total (Dth)**
Forecasted Shut-in Production (Dth/day)	59	780	0	0	0	**25,950**
Actual Shut-in Production (Dth/day)	0	0	5,724 (28 days)	0	0	**160,272**

Table 6.2 – 2017

	June	July	August	September	October	Total (Dth)
Forecasted Shut-in Production (Dth/day)	0	0	0	0	0	**0**