INTRODUCTION AND BACKGROUND

In September of 2016, the merger of Dominion Resources Inc. and Questar Corporation (the parent company of Questar Gas Company) was completed. This business combination created one of the nation's largest electric and natural gas energy companies. In the words of Thomas F. Farrell II, Chairman, President and Chief Executive Officer of Dominion Resources, Inc., "Dominion is very pleased to join with Questar. Like Dominion, Questar has a history of safe and reliable operations, integrity and a firm commitment to its employees and the communities it serves. Questar's customers can count on a continuation of the high-quality service they have enjoyed for years."[2]

Dominion Resources, Inc. is headquartered in Richmond, Virginia, and has a portfolio of approximately 26,200 MW of electric generation and 6,600 miles of electric transmission lines. On the natural gas side, Dominion Resources, Inc. owns and operates 15,000 miles of transmission, gathering and storage pipelines. Dominion operates natural gas storage facilities totaling one Tcf of capacity. Total utility and retail customers served by Dominion Resources, Inc. exceed 6 million.

Dominion Resources, Inc. is committed to protecting the health and safety of the public by reducing its carbon footprint. Since the year 2000, Dominion Resources, Inc. has reduced its corporate-wide carbon intensity rate (average CO2 emissions rate per unit of electric output) by 43%. In its natural gas facilities, 4.4 Bcf of methane has been saved through leak-reduction programs, equipment replacement and routine maintenance. Dominion Resources, Inc. has helped bring more than 1,000 MW of solar power into operation in the U.S. since 2013, a level sufficient to power approximately 250,000 homes at peak solar output.[3]

Following shareholder approval on May 10, 2017, Dominion Resources, Inc. changed its name to Dominion Energy, Inc. This planning document pertains only to the natural gas distribution operations of Dominion Energy, Inc. that are subject to the jurisdictions of the Utah and Wyoming Commissions. The natural gas utility providing service in Utah, Wyoming and Idaho is referred to herein as "Dominion Energy" or the "Company". The corporate headquarters of these operations will remain in Salt Lake City, Utah. Salt Lake City will also be the operating headquarters of Dominion Energy's Western Region.[4]

The Company's Utah, Wyoming, and Idaho service territories continue to experience strong growth. The Company reached the one-million-customer mark during September of 2016.

The single most significant development in the energy industry over the previous year was the advent of a new U.S. Federal Administration. President Trump campaigned on a platform of maximizing use of American energy resources, eliminating burdensome regulations, expediting and rebuilding energy infrastructure, and freeing the U.S. from

[2] "Dominion Resources, Questar Corporation to Combine," Richmond, Va., PRNewswire, February 1, 2016.
[3] "Dominion's Environmental Performance Continues to Improve," Richmond Va., PRNewswire, May 10, 2017.
[4] "Questar Corporation and Dominion Resources to Combine," Questar Corporation, News Release, Salt Lake City, Utah, February 1, 2016.

dependence on foreign oil. President Trump's administration could portend an era of change for domestic energy producers and transporters.

As with any new Administration, there is a certain level of uncertainty as new policies and programs are unveiled. There are new heads of the Department of Energy, Department of the Interior, and the Environmental Protection Agency. The new Secretary of State is the former CEO of Exxon Mobil, Rex Tillerson. While American energy interests in general welcome tax and regulatory reform, there are concerns over potential future border taxes, limitations on the use of foreign steel for energy pipeline projects, and excessive protectionism.

On March 28, 2017, in a widely expected move, the Trump Administration issued an executive order beginning the process of rescinding some of the climate-change policies of the previous administration. The order, entitled "Presidential Executive Order on Promoting Energy Independence and Economic Growth," promotes clean and safe development of U.S. energy resources. The order required all executive departments and agencies to immediately being reviewing existing regulations that burden the development of domestic energy resources beyond the degree necessary to protect the public interest and comply with the law. Of particular interest to the energy industry is the specific requirement in the order for the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan for consistency with the presidential order.

The Clean Power Plan had its beginnings on June 2, 2014, when the EPA issued a draft rule requiring a reduction of carbon dioxide (CO_2) emissions from existing coal plants by up to 30% by 2030, based on 2005 emission levels. The public comment period for the proposed rule, known as the Clean Power Plan, ended on December 1, 2014, with the EPA receiving more than two million comments. Compliance with the draft rule was expected to increase natural gas-fired generation, and, to a lesser extent, renewable generation such as solar, wind, tidal, and geothermal. It was also expected that demand-side efficiency measures would be expanded under the draft rule.

The final version of the Clean Power Plan was released on August 3, 2015, with a number of notable changes from the June 2014 version. After further consideration, the EPA acknowledged concerns that the 2014 draft rule could have driven down investment in renewables and accelerated, over the long term, investment in natural gas-fired generation. As a result, the final rule mandated a substantially higher use of renewables in the long term that could negatively impact investment in natural gas.[5] The final rule required state agencies to submit their implementation plans by September of 2016 or ask the EPA for an extension to 2018. While a number of states and businesses supported the rule, more than two dozen states and multiple energy-industry groups filed legal challenges to oppose the rule. The challengers argue that the EPA does not have authority under the Clean Air Act to regulate carbon dioxide emissions from power plants and that the rule would increase the cost of electric power and would harm workers and businesses.

On February 9, 2016, the U.S. Supreme Court, on a five–to-four vote, granted a stay of the Clean Power Plan pending judicial review. A ten-judge panel from the U.S. Court of

[5] "EPA power rule not as gas-friendly as hoped," Bobby McMahon, Jim Ostroff, Jonathan Nelson, George McGuirk, Gas Daily, Platts McGraw Hill Financial, August 4, 2015, pages 5 and 6.

Appeals for the D.C. Circuit heard oral arguments in this case in September of 2016. A decision by the D.C. Circuit was still pending when the March 2017 presidential order was issued. The Clean Power Plan may have been the most ambitious initiative ever undertaken by the EPA. Regardless of the outcome of the plan, however, it is apparent that fundamental changes in the mix of power generating fuels have been taking place and will continue to take place in the U.S. That shift will move the industry generally away from the use of coal towards more environmental-friendly fuel sources.

During 2016, 27 GW of electric generating capacity was added to the U.S. power grid. Capacity retirements during 2016 totaled approximately 12 GW leaving a net gain of approximately 15 GW, the largest change in absolute terms since 2011. The top three 2016 electric-capacity additions consisted of natural gas (9.0 GW), wind (8.7 GW) and solar (7.7 GW).[6]

In 2016, for the first time since the Energy Information Administration (EIA) has been keeping data, natural-gas-fired generation exceeded coal-fired generation in the U.S. on an annual basis. As a percentage of all energy sources, natural gas comprised 33.8% and coal comprised 30.4%.[7] The EIA expects that additions of utility-scale natural-gas-fired generating capacity to the power grid during 2017 will total more than 11 GW, and in 2018 will exceed 25 GW.[8]

Recent EIA data indicates that energy-related CO_2 emissions in the U.S., during calendar year 2016, totaled 5.17 billion metric tons, a decline of 1.7% from the 2015 level of 5.26 billion metric tons. Energy related CO_2 emissions peaked in 2007 at a level of 6.00 billion metric tons. The 2016 level is nearly 14% below the 2007 level.[9] The general decline from 2007 is largely attributed to weakness in the economy due to the recession, improving energy efficiency, increased use of renewables, and growing use of abundant natural gas. The replacement of coal-fired power generation with generation from less carbon-intensive natural gas has been fundamental to the general decline over the last nine years.[10]

The new Trump Administration will also leave its mark on the Federal Energy Regulatory Commission (FERC). The FERC regulates, among other things, the interstate natural gas pipeline system used to deliver natural gas to local distribution companies in the U.S., including those upstream pipelines that deliver supplies to the Company. The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate. By rule, not more than three members of the FERC may come from the President's party. All have an equal vote and the President selects the Chairman. The FERC requires at least three members to operate as a quorum.

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[6] "U.S. electric generating capacity increase in 2016 was largest net change since 2011," Today in Energy, U.S. Energy Information Administration, February 27, 2017.

[7] "Table ES1.B. Total Electric Power Industry Summary Statistics, Year-to-Date 2016 and 2015," Electric Power Monthly with Data for December 2016, U.S. Energy Information Administration, Department of Energy, February 2017.

[8] "Natural gas-fired generating capacity likely to increase over next two years," Today in Energy, U.S. Energy Information Administration, January 30, 2017.

[9] "March 2017 Monthly Energy Review," U.S. Energy Information Administration, U.S. Department of Energy, Released: March 28, 2017.

[10] "U.S. energy-related CO2 emissions fell 1.7% in 2016," Today in Energy, U.S. Energy Information Administration, April 10, 2017.

Several developments, one of which is historic, have taken place in the composition of the FERC over the last IRP year. In January of 2016, Commissioner Tony Clark, the lone Republican, announced that he would not seek a new term. His term ran through June of 2016 and he extended his departure date to the end of September 2016. The loss of Commissioner Clark left the FERC with three members, the minimum necessary to operate as a quorum.

During January of 2017, President Trump appointed Commissioner Cheryl LaFleur as Acting Chairman of the Commission. Also in January 2017, Chairman Norman Bay left the Commission abruptly. This left the FERC with just two members, Acting Chairman LaFleur and Commissioner Collette Honorable. For the first time in the nearly 40-year existence of the FERC, the Commission was without a quorum. Further complicating matters, Commissioner Honorable announced, on April 28, 2017, that she would not seek another term with the FERC after the expiration of her term on June 30, 2017.

Prior to the departure of Chairman Bay, the Commission expedited dozens of orders and clarified the delegated authority of Commission staff to process certain filings. During early February of 2017, Acting Chairman LaFleur canceled the regular monthly open meetings of the FERC until further notice. The lack of a quorum effectively brought to a halt the approval process necessary to provide critically needed energy infrastructure for the U.S.

On May 8, 2017, President Trump announced his intent to nominate two individuals to fill vacancies in the FERC. The nominees are Neil Chatterjee, energy advisor to Senate Majority Leader Mitch McConnell, and Robert Powelson, President of the National Association of Regulatory Utility Commissioners.[11] The confirmation of these two nominees would reconstitute a quorum.

Notwithstanding a recent rebound in natural gas prices, the energy price environment remains relatively weak. Natural gas prices began declining in early 2014. The average Henry Hub price during the month of February 2014 was $6.00 per Dth. By March of 2016, the average monthly Henry Hub price had declined to a low of $1.73 per Dth. By December of 2016, the average monthly Henry Hub price had recovered to $3.59 per Dth, the highest average monthly price since November of 2014. The average Henry Hub price for April of 2017 stood at a level of $3.10 per Dth.

During 2016, natural gas spot prices averaged $2.49 per Dth at Henry Hub. This was the lowest average annual price since 1999. During the first quarter of 2016, warmer-than-normal winter temperatures and high levels of natural gas in storage caused prices to decline. By late spring, increasing demand from multiple sectors, including power generation, and declining production exerted moderate upward pressure on prices. The onset of winter caused prices to increase more sharply.[12]

[11] "President Donald J. Trump Announces Intent to Nominate Personnel to Key Administration Posts," The White House, Office of the Press Secretary, May 8, 2017.
[12] "Natural gas prices in 2016 were the lowest in nearly 20 years," Today in Energy, Energy Information Administration, U.S. Department of Energy, January 13, 2017.

Regional prices at the Opal, Wyoming hub also recovered moderately during 2016 reaching a peak of $3.72 per Dth on January 1, 2017. On May 9, 2017, the average daily mid-point price at Opal was $2.685 per Dth.

In recent months the Henry Hub natural gas futures forward curve had prices increasing from the low $3.00 per-Dth range during the summer months of 2017 to the mid $3.00 per Dth range during the winter of 2017-2018. After this point in time, the forward curve is projected to swing seasonally for the next two years from the high $2.00 per Dth range during the summers to the low $3.00 per Dth range during the winters.

According to the EIA, natural gas production in the Lower 48 states declined in 2016 due to lower prices. Lower-48 production averaged 80.39 Bcf/D in 2016, a 1.3% decline from 2015. Natural gas production actually increased from 2015 to 2016 in Pennsylvania and Ohio (Marcellus and Utica shale plays) but declined in all other regions of the Country.[13]

The recent rebound in natural gas prices has had an impact on the rig count. The oil field services company, Baker Hughes, monitors and publishes drilling rig data. Since Baker Hughes began tracking rig data in 1987, the highest weekly gas-directed rotary rig count for North America occurred during August and September of 2008 when the peak reached 1,606 rigs on two occasions. On two other separate occasions during August of 2016, the gas-directed rig count dropped to an all-time low of 81 rigs. By May 12, 2017, the gas-direct rig count had recovered to a level of 172. Due to the greater economic interest in oil, the gas directed rig count at this point in time is only about 19 % of the total rigs in operation[14]

The relatively low energy price environment of 2016 continued to affect the profitability of natural gas and oil exploration and production companies. These companies have been hurt by low commodity prices, expiring hedges, and high levels of balance-sheet debt. Industry consultant Graves and Company, based in Houston, Texas, estimated that world-wide job losses in the energy sector due to recent years of depressed prices is over 440,000 as of mid-February 2017. Graves estimates that roughly 40% of those losses have been in the U.S. Even with the recent price recovery, Graves expects that job losses will continue, particularly for companies having significant offshore and international exposure.[15]

According to the law firm of Haynes and Boone, from the beginning of 2015 through April 27, 2017, 123 North American oil and gas producers filed for bankruptcy. These cases involve approximately $80 billion in cumulative secured and unsecured debt. It is likely that more producer bankruptcy filings will be made during the remainder of 2017 although it appears that the filing rate is slowing this year due perhaps to improving commodity prices. During 2015, 44 oil and gas producers filed for bankruptcy, during 2016, 70 filed for bankruptcy, and as of April 27th, only nine more companies have filed during 2017.[16]

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[13] "U.S. crude oil and natural gas production both fell in 2016," Today in Energy, Energy Information Administration, U.S. Department of Energy, March 8, 2017.
[14] "North America Rig Count Current Week Data," Baker Hughes, http://www.bakerhughes.com/, May 5, 2017.
[15] "More Than 440,000 Global Oil, Gas Jobs Lost During Downturn," Rigzone, Valerie Jones, Rigzone Staff, February 17, 2017. http://www.rigzone.com/news/oil_gas/
[16] "Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, April 27, 2017.

During December of 2016, the EIA released its annual report on natural gas proved reserves for the prior calendar year. On December 15, 2016, the EIA reported that U.S. proved reserves of natural gas at year-end 2015 were 324.3 Tcf. This level was 64.5 Tcf lower than the 2014 level, a decrease of approximately 16.6%. The decline in 2015 end-of-year reserves was a direct result of reduced drilling activity caused by lower natural gas prices. Proved reserves are estimated volumes of natural gas from known reservoirs that geologic and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions.[17]

Total U.S. discoveries during 2015 totaled 34.7 Tcf, approximately 95% of which were extensions to existing natural gas fields. By source, the 34.7 Tcf discovered in 2015, can be broken down as 0.1 Tcf from coalbed methane formations (0.3%), 25.9 Tcf from shale formations (74.6%), and 8.7 Tcf from conventional and other tight formations (25.1%). Texas continues to have the largest proved natural gas reserves, followed by Pennsylvania, Oklahoma, West Virginia and Wyoming. During 2015, Ohio added more than 5 Tcf in the Utica Shale play moving it up two places to become the ninth-largest natural gas reserves state.[18]

Each year, the EIA tracks, throughout the country, the design capacity of natural gas storage facilities at the beginning of the traditional injection season. The total working-gas design capacity in the Lower 48 states during the period from November 2015 to November 2016 increased slightly from 4,658 Bcf to 4,688 Bcf. Since November 2013, total working-gas design capacity has been relatively flat. For the third consecutive year, no new underground storage facilities initiated operations in the U.S. For the year prior to November 2016, eight existing facilities expanded operations by one Bcf or more. All eight are located in the South Central region, specifically, Texas, Oklahoma, Louisiana, and Mississippi. Design capacity in the Mountain region over the same period remained flat.[19]

The 2016 storage injection season began in April with a record high inventory level. By the end of the traditional injection season at the end of October, a new month-end-high record was set. For the week ending November 11, 2016, national working gas storage volumes set a new all-time record high of 4,047 Bcf.[20] The traditional 2016 injection season had net injections of 1,543 Bcf. By comparison, net injections for the 2015 traditional injection season totaled 2,475 Bcf.[21] By the end of the 2016-2017 traditional withdrawal season, on March 31, 2017, the lower-48 inventory level stood at 2,051 Bcf. This level was 427 Bcf lower than the same time last year and was 265 Bcf or 14.8% above the five year average.[22]

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[17] "U.S. oil and natural gas proved reserves declined in 2015 because of lower prices," Today in Energy, Energy Information Administration, U.S. Department of Energy, Steve Grape, December 15, 2016.
[18] "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2015," U.S. Energy Information Administration, U.S. Department of Energy, December, 2016. Components may not add to totals due to independent rounding.
[19] "Underground Natural Gas Working Storage Capacity," Energy Information Administration, U.S. Department of Energy, Release Date: April 3, 2017.
[20] Ibid.
[21] "Table 9. Underground natural gas storage – by season, 2015 – 2017," Natural Gas Monthly, Energy Information Administration, U.S. Department of Energy, March 2017.
[22] "Weekly Natural Gas Storage Report," Energy Information Administration, U.S. Department of Energy, For the week ending March 31, 2017, Released April 6, 2017.

The Company discusses its use of natural gas storage facilities in the Gathering, Transportation, and Storage section of this report.

As former FERC Chairman Norman Bay was leaving the Commission in January of 2017, his letter of resignation made mention of the fact that during 2016, the FERC approved the most interstate pipeline capacity since 2007. The FERC Office of Energy Projects issues a monthly Energy Infrastructure Update. During calendar year 2016, the FERC certificated 18.2 Bcf/D of pipeline capacity, up from 15.7 Bcf/D in 2015. The miles of pipeline certificated during 2016 were over twice the level certificated during 2015, and compression, in horsepower, certificated in 2016, was 2.7 times that certificated during the previous year. Pipeline capacity actually placed in service, however, declined from 7.9 Bcf/D in 2015 to 7.1 Bcf/D in 2016. The miles of pipeline placed in service also declined from 423.5 miles in 2015 to 391.7 in 2016.[23] In explaining the differences between certificated and placed-in-service metrics, a FERC spokesperson cited the lag for construction activities (possibly two to three years). In addition, the spokesperson indicated that other holdups can occur such as those faced by Williams' Constitution Pipeline project and Dominion Energy, Inc.'s New Market Project in New York.[24]

The constantly evolving landscape of energy supplies and markets in the U.S. punctuates the need for timely approvals of interstate pipeline projects by regulatory agencies. For example, the Rockies Express Pipeline (REX) was completed in November 2009. This 1.8 Bcf/D pipeline, 1,713 miles long, was constructed to move plentiful supplies of natural gas from Wyoming and Colorado to eastern markets. However, unanticipated development of shale gas production in the Marcellus and Utica basins transformed the Northeast into a major supply region. Consequently, the owners of REX initiated a project to reverse flow and provide east-to-west service on Zone 3 of the REX system. The project was placed in service in August of 2015 providing full bidirectional flow of 1.8 Bcf/D. During January of 2017, REX announced the completion of a capacity expansion project which added three additional compressor stations and upgraded two other stations. This project received FERC approval in March of 2015 and the compression enhancement added 800 MMcfd of east-to-west capacity serving Midwestern markets. Reportedly, initial east-to-west flows are averaging close to the maximum capacity of 2.6 Bcf/D.[25]

Notwithstanding the slight natural gas production decline in 2016, the growth in U.S. natural gas production in recent years, and expectations of future production growth have increased interest in U.S. LNG exports. The EIA reports that construction at six LNG export terminals is currently underway. The Sabine Pass facility near the Texas/Louisiana border began exporting LNG during February of 2016. Sabine Pass currently has three fully operational trains with two more under construction. The Cove Point LNG facility in Maryland, owned by Dominion Energy, Inc., is expected to come online by the end of 2017.

[23] "Energy Infrastructure Update For December 2016," Federal Energy Regulatory Commission, Office of Energy Projects, Released February 1, 2017.
[24] "Rapid pipeline growth continues in 2016: FERC," Gas Daily, Platts McGraw Hill Financial, February 3, 2017, pages 6 and 7.
[25] "REX Zone 3 capacity expansion enters full service, increasing Northeast takeaway capacity," Natural Gas Weekly Update: for week ending January 11, 2017, U.S. Energy Information Administration, Release Date: January 12, 2017.

Other LNG facilities currently under construction are: Cheniere Energy's Corpus Christi facility in Texas, Sempra Energy's Cameron terminal in Louisiana, Freeport LNG's facility in Texas, and most recently, Kinder Morgan's Elba Island facility in Georgia.[26] As of January 2017, 13 U.S. LNG export facilities had been proposed to the FERC. Of those proposals, 6 are pending applications and 7 are projects in the pre-filing phase.[27]

The proposed Jordan Cove LNG export facility on the Oregon coast is of particular interest to the Company because the addition of this facility could impact prices in the Rockies. Veresen Inc., the developer of Jordan Cove, acquired a 50% interest in the Ruby Pipeline in 2014. The Ruby Pipeline extends from the Opal Hub in Wyoming to the Malin Hub in Oregon and crosses the Company's northern service territory. The Company regularly purchases natural gas at the Opal Hub. The Ruby Pipeline provides direct access to the Jordan Cove LNG facility through the proposed Pacific Connector Gas Pipeline.

On March 11, 2016, the FERC rejected the Pacific Connector pipeline and consequently the Jordan Cove LNG project on the grounds that the applicant had not adequately demonstrated a market need. The FERC specified that its decision was issued without prejudice and that the developers could submit a new application to construct the facilities in the future if they are able to show a market need for the project.[28] Less than two weeks after the FERC Order, Veresen announced that it had signed a long-term capacity agreement for the Jordan Cove facility with a Tokyo-based electric utility joint venture. The agreement includes the purchase of approximately one quarter of the 6 million-tons-per-annum liquefaction capacity of the facility.[29] On April 8, 2016, Veresen filed an application with the FERC requesting a rehearing related to the pipeline and LNG projects, citing recently-executed precedent agreements for more than 75% of the Pacific Connector Pipeline project and more than 50% of the initial design capacity of the LNG facility.[30] The FERC denied the request to reopen the record to allow the inclusion of these long-term agreements.

In early 2017, Veresen met with FERC Staff to discuss the project and its refiling plan. On January 23, 2017, Veresen submitted its Request for Approval of Pre-Filing Review for the Jordan Cove Energy Project and the Pacific Connector Gas Pipeline. Veresen indicated that it intended to file applications on or about August 30, 2017. On February 10, 2017, the FERC issued its approval of Veresen's pre-filing request.[31]

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[26] "In the News: U.S. liquefaction capacity continues to expand," Natural Gas Weekly Update for week ending March 1, 2017, U.S. Energy Information Administration, Release Date: March 2, 2017.
[27] "Proposed North American LNG Export Terminals: As of January 5, 2017," Federal Energy Regulatory Commission, Natural Gas Industry, Updated February 22, 2017.
[28] "Order Denying Applications for Certificate and Section 3 Authorization," Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P., Docket No. CP13-483-000, Pacific Connector Gas Pipeline, Docket No. CP13-492-000, Issued March 11, 2016.
[29] "Jordan Cove in offtake deal with JERA," Gas Daily, Platts McGraw Hill Financial, March 24, 2016, Pages 6 and 7.
[30] "Request for Rehearing of Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP," Before the Federal Energy Regulatory Commission, Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP, Docket No. CP13-483-000, Docket No. CP13-492-000, April 8, 2016.
[31] "Re: Approval of Pre-Filing Request," Federal Energy Regulatory Commission, Correspondence from Ann F. Miles, Director Office of Energy Projects to Elizabeth Spomer, President and CEO Jordan Cove Energy Project LP and Pacific Connector Gas Pipeline LP, February 10, 2017.

Data from Platts Analytics' Bentek Energy suggests that some 10.1 Bcf/D of liquefaction capacity will be available at US export facilities by the end of 2020. From February of 2016, export capacity has grown from zero to approximately 2.1 Bcf/D in early 2017.[32] While some are concerned about an excess of capacity in the future, producers are optimistic that the world market for US LNG will continue to grow, at least in the short term. The EIA expects LNG exports to make up a growing share of natural gas exports surpassing pipeline exports of natural gas by 2020.[33]

The Company further discusses its use of interstate pipeline capacity and its interest in LNG liquefaction and storage facilities in the Gathering, Transportation, and Storage and the Peak-Hour Demand and Reliability sections of this document.

The Company continues to support the use of clean burning compressed natural gas (CNG) as a vehicle fuel. Total gallons of natural gas used as a vehicle fuel on the Company's system declined by 1,270,791 gallons for 2016 (3,206,119 gallons) compared to 2015 (4,476,910 gallons). Which is a decrease of 28.4%. The price per gallon of gasoline continues to be within $0.50 of the posted price of CNG. Utah still remains in the top five U.S. states of CNG Infrastructure according to NGVAmerica (see Figure 2.1).[34]

For information regarding the location of the Company's CNG stations refer to Exhibit 2.1. The Company's CNG refueling locations in Cedar City and Park City were closed in 2016 due to reduced usage and aging equipment. In 2017 refueling locations in Fillmore and Rock Springs will be closed for similar reasons. The Company will still maintain twenty-seven public refueling locations with another 18 public locations operated by private and state owners.

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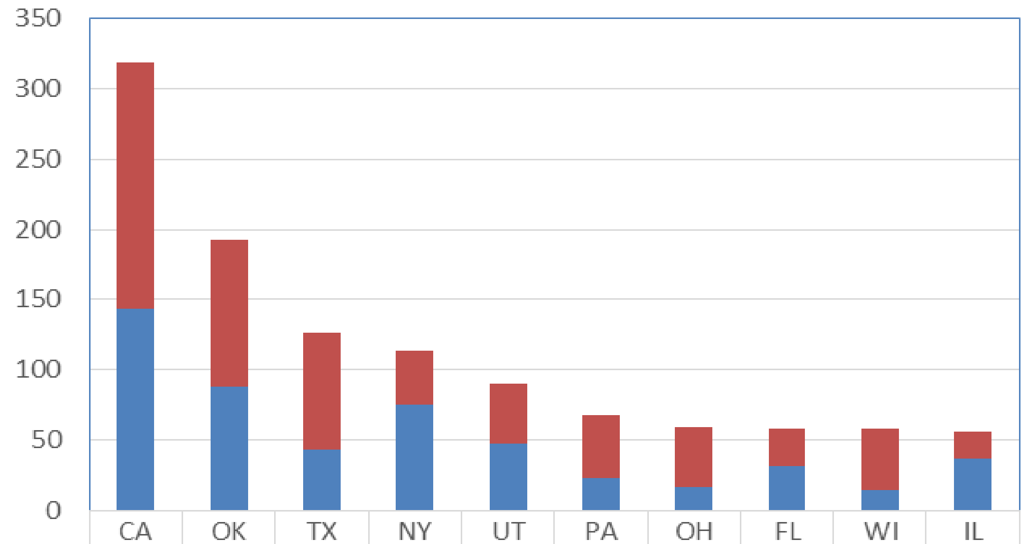
[32] "LNG buyers pushing US exporters to be flexible," Harry Weber and Grant Gunter, Gas Daily, Platts McGraw Hill Financial, February 10, 2017, pages 4 and 5.
[33] "Liquefied natural gas exports expected to drive growth in U.S. natural gas trade," Katie Dyl, Today in Energy, U.S. Energy Information Administration, February 22, 2017.
[34] https://www.ngvamerica.org/stations/



	CA	OK	TX	NY	UT	PA	OH	FL	WI	IL
CNG Public	174	105	83	39	43	45	42	27	44	19
CNG Private	144	88	43	75	47	23	17	31	14	37

Figure 2.1 - Top Ten U.S. States: CNG Infrastructure (Dec 2016)

Refuse haulers and cement trucks continue to be the fastest growing segment of vehicles using natural gas as fuel. Geneva Rock Products recently added twenty-five new CNG cement trucks to its fleet and expects to add additional trucks in the future. These companies use “behind the fence” on-site fueling solutions, and utilize the Company’s public fueling infrastructure as a back-up to their respective activities. Some of the larger CNG fleets in Utah are Utah Transit Authority (UTA), Salt Lake City, Salt Lake County recycling, Waste Management, United Parcel Service (UPS), ACE disposal, Frito Lay and Sysco Foods.

The Company expects that CNG usage at the Company’s stations will continue to decline in 2017 due to the price differential between CNG and gasoline.

Over the past decade, the increase in shale gas production has focused attention on the environmental impacts of hydraulic fracturing. On June 4, 2015, the EPA released its Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources. The draft assessment reported that there was no evidence of widespread, systematic impacts on drinking water resources from hydraulic fracturing activities in the U.S. The EPA also identified some “potential vulnerabilities” which it clarified was not a list of documented impacts. Those potential vulnerabilities include hydraulic fracturing conducted directly in formations containing drinking water resources, aboveground spills, inadequately treated wastewater and inadequately cemented wells.[35]

[35] “Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources,” External Review Draft, United States Environmental Protection Agency, Office of Research and Development, June 4, 2015.

Companies in the oil and gas industry supported the EPA study by providing data for review and analysis. Industry has voluntarily provided additional information from FracFocus, a fracturing chemical registry where well-specific chemical disclosures can be made.[36] Approximately 125,000 well sites have been registered with FracFocus. Dominion Energy Wexpro, the Company's production affiliate, is among the companies voluntarily providing data to FracFocus.

In January of 2016, the Science Advisory Board (SAB), an independent scientific panel assembled to advise the EPA, issued a report to the EPA disputing the EPA's finding that there was no evidence of widespread systematic impacts to groundwater from hydraulic fracturing.[37] The Independent Petroleum Association of America (IPAA) and others responded by disputing the SAB's challenge to the EPA's findings, arguing that the draft EPA report was very much in line with the scientific consensus on hydraulic fracturing.[38]

During December of 2016, the EPA released its final report on hydraulic fracturing which concluded that hydraulic fracturing activities "can impact drinking water resources under some circumstances."[39] A spokesman for the IPAA responded that while the new report removes a few words, the conclusion is the same, "there is no data to prove widespread impacts to drinking water."[40]

On March 20, 2015, the U.S. Department of Interior, Bureau of Land Management (BLM), released its final rules governing hydraulic fracturing on federal and tribal lands to be implemented within 90 days. Multiple organizations representing the exploration and production industry opposed the rules as burdensome and lacking cost justification. The IPAA and the Western Energy Alliance filed a petition with the U.S. District Court for Wyoming, asking the federal court to review the proposed rules. The states of Colorado, North Dakota, Utah and Wyoming, and the Ute Indian Tribe all joined in the petition. On June 21, 2016, U.S. District Judge Scott Skavdahl, issued an order in response to the petitions stating that Congress had not delegated to the Department of the Interior legal authority to regulate hydraulic fracturing.[41]

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[36] FracFocus is operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

[37] "Science panel disputes EPA fracking finding," Gas Daily, Platts McGraw Hill Financial, January 8, 2016, Pages 10 & 11.

[38] Correspondence from Lee Fuller, Executive Vice President, Independent Petroleum Association of America, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency, dated December 11, 2015. Correspondence from Erik Milito, Group Director, Upstream and Industry Operations, American Petroleum Institute, to Edward Hanlon, Designated Federal Officer, EPA Science Advisory Board Staff, U.S. Environmental Protection Agency, dated December 14, 2015.

[39] "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States," United States Environmental Protection Agency, Office of Research and Development, Washington, DC, EPA-600-R-16-236ES, December, 2016.

[40] "Final EPA report sees impacts from fracking," Gas Daily, Platts McGraw Hill Financial, December 14, 2016, Pages 3 and 4.

[41] "Order on Petitions for Review of Final Agency Action," In the United States District Court for the District of Wyoming, Scott W. Skavdahl, United States District Judge, Case No. 2:15-CV-043-SWS, June 21, 2016.

Public misperceptions of hydraulic fracturing persist, however. The public health benefits that have been achieved by the increased use of clean burning natural gas, most of which comes from hydraulically fractured wells, are not widely understood. On April 4, 2017, the State of Maryland became the third state, after New York and Vermont, to ban hydraulic fracturing. None of these states have substantial natural gas resources, although, minor portions of the Marcellus and Utica shales lie under the western counties of Maryland. Two additional states, Oregon and Nevada, are also considering bans.

Wexpro II Agreement and Gas-Producing Property Acquisitions

Over the course of approximately 35 years, the Company's customers have benefited from supplies delivered at cost-of-service to the Company pursuant to the Wexpro Agreement.[42] Beginning in the fall of 2011, the Company, Dominion Energy Wexpro, and regulatory agencies in Utah and Wyoming began discussing the possibility of Dominion Energy Wexpro acquiring oil and gas properties or undeveloped leases for the mutual benefit of the Company's customers and Dominion Energy Wexpro, under an agreement similar to the Wexpro Agreement. This arrangement, referred to as the Wexpro II Agreement, was designed to incorporate essentially the same terms and conditions of the Wexpro Agreement (known as the Wexpro I Agreement).

On March 28, 2013, the Utah Commission issued its Report and Order approving the Company's Wexpro II Agreement[43] and on October 16, 2013, the Wyoming Commission issued its Order approving the Wexpro II Agreement.[44] Subsequently, the Utah and Wyoming Commissions approved the inclusion of the Trail Unit and the Canyon Creek Unit as Wexpro II properties.

On January 9, 2017, the Company filed an application with the Utah Commission requesting approval of the Vermillion Acquisition as a Wexpro II property.[45] The Company also filed an application with the Wyoming Commission on January 10, 2017.[46] The Vermillion Acquisition includes natural gas producing properties within the Vermillion Basin in the Kinney, Trail, Whiskey Canyon, and Canyon Creek Units. The Vermillion Acquisition also included 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

[42] For more information on the Wexpro Agreement, see the Cost-of-Service Gas section of this report.
[43] Utah Public Service Commission, "In the Matter of the Application of Questar Gas Company for Approval of the Wexpro II Agreement," Docket No. 12-057-13, Report and Order, Issued March 28, 2013.
[44] The Public Service Commission of Wyoming, "In the Matter of the Application of Questar Gas Company for Approval of the Wexpro II Agreement," Docket No. 30010-123-GA-12 (Record No. 13347), Memorandum Opinion, Findings and Order Approving the Wexpro II Agreement, Issued October 16, 2013.
[45] "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," Utah Public Service Commission, Docket No. 17-057-01, January 9, 2017.
[46] "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," The Public Service Commission of Wyoming, Docket No. 30010-162-GA-17 (Record No. 14631), January 10, 2017.

Wexpro II as was the case for the Whiskey Canyon and Canyon Creek properties in the Vermillion Acquisition.

Technical conferences were held during February of 2017 in Utah and Wyoming to discuss and provide information to regulatory agencies. On February 21, 2017, the Utah Division of Public Utilities (Division) and the Utah Office of Consumer Services (Utah OCS) filed direct testimony in the Utah Docket. On February 21, 2017, the Wyoming Office of Consumer Advocate (Wyoming OCA) filed direct testimony in the Wyoming Docket.

On March 2, 2017, the Company, Dominion Energy Wexpro, the Division, the Utah OCS, and the Wyoming OCA submitted a Settlement Stipulation with the Utah and Wyoming Commissions. As the cost-of service gas produced from existing Kinney wells currently exceeded market prices, the Settlement Stipulation provided for the withdrawal of the Kinney Unit property from current consideration under Wexpro II. The Settlement Stipulation allows the Kinney property to be resubmitted for regulatory approval in the future.

On March 9, 2017, the Utah Commission held a hearing and issued a bench ruling approving the Vermillion Acquisition Settlement Stipulation. The Utah Commission then issued an "Order Memorializing Bench Ruling Approving Stipulation" on March 30, 2017.[47] The Wyoming Commission held a hearing on March 17, 2017, and issued a bench ruling approving the Settlement Stipulation. The Wexpro I Agreement, the Wexpro II Agreement and the stipulations in the Trail, Canyon Creek, and Vermillion dockets are collectively known as the "Wexpro Agreements."

The Wexpro Agreements provide a framework where the Company's customers can continue to receive the long-term benefits of cost-of-service production. The Company believes that the Wexpro Agreements provide a valuable long-term resource to customers.

Wyoming IRP Process

The Company has been involved in integrated resource planning in the state of Wyoming since the early 1990s. In 1992, the Wyoming Commission ordered the Company to prepare and file integrated resource plans.[48] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to integrated resource planning. The Commission proposed the rule to ". . . give the Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[49]

[47] "In the Matter of the Application of Questar Gas Company for Approval of the Vermillion Acquisition as a Wexpro II Property," Utah Public Service Commission, "Order Memorializing Bench Ruling Approving Stipulation," Docket No. 17-057-01, March 30, 2017.

[48] "In the Matter of the Application of Mountain Fuel Supply Company to File its Integrated Resource Plan as Directed by the Commission in Docket No. 30010-GI-90-8," Findings, Conclusions and Order, Docket No. 30010-GI-91-14, May 21, 1992.

[49] Before the Public Service Commission of Wyoming, "In the Matter of the Proposed Adoption of Chapter 2, Section 253 of the Commission Procedural Rules and Special Regulations Regarding Integrated Resource Planning," Order Initiating Rulemaking, Docket No. 90000-107-XO-09 (Record No. 12032, February 3, 2009).

On May 12, 2009, the Wyoming Commission approved Rule 253 and on January 24, 2011 the Wyoming Commission approved the natural gas IRP guidelines.[50]

The Company filed its 2016-2017 IRP on June 15, 2016, with the Wyoming Commission. Commission Staff solicited written public comments on the IRP filing by noticing the matter on the Wyoming Commission's open meeting agendas. On April 11, 2017, Commission Staff issued a report on its review of the 2016-2017 IRP. Commission Staff found no areas of concern with the results and projections in the 2016-2017 IRP, and concluded, ". . . it is evident that the Company is actively identifying, evaluating, and executing projects and plans to meet their obligation to maintain Wyoming services at safe and reliable levels."[51] The Wyoming Commission addressed the Company's 2016-2017 IRP in its Open Meeting on April 18, 2017. The Commission Staff recommended that the Wyoming Commission issue a letter order accepting the Company's IRP for filing. On April 25, 2017, the Wyoming Commission issued a letter order directing the 2016-2017 IRP be placed in the Commission's files with no further action being taken and closed the matter.[52]

At its regularly scheduled Open Meeting on October 6, 2016, the Wyoming Commission received a presentation from representatives of the Company. Topics discussed included:

- 2015-2016 IRP Year Production
- Review of the 2016 Dominion Energy Wexpro Drilling Program vs. 5 Year Curve
- Dominion Energy Wexpro 2016 Headcount Reductions
- O&M and G&A Reductions
- Trail Compression Project
- Wexpro II Opportunities and Strategy

Utah IRP Process

Over the previous decade, the Utah Commission has promulgated new IRP standards and guidelines. This implementation process has included numerous discussions between IRP stakeholders in public meetings and the submission of extensive comments.

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[50] Correspondence from the Public Service Commission of Wyoming; Alan B. Minier, Chairman, Steve Oxley, Deputy Chairman, and Kathleen "Cindy" Lewis, Commissioner, To All Wyoming Natural Gas Utilities, dated January 24, 2011.

[51] Memorandum from Kara Seveland, Jess Bottom and John Burbridge to Chairman Russell, Deputy Chair Brighton Fornstrom and Commissioner Sessions Cooley; Re: Docket No. 30010-152-GA-16 (Record No. 14416) In the matter of the filing of Questar Gas Company Integrated Resource Plan for Year June 1, 2016 to May 31, 2017; April 11, 2017; Page 9.

[52] Letter Order, To: Jenniffer Nelson Clark, Corporate Counsel, Questar Gas Company, From: John S. Burbridge, Assistant Secretary Wyoming Public Service Commission, Re: In The Matter of the Filing of Questar Gas Company's Integrated Resource Plan for Plan Year June 1, 2016 to May 31, 2017 – Docket No. 30010-152-GA-16 (Record No. 14416), Issued: April 25, 2017.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Guidelines) to be effective starting with the Company's 2010 IRP.[53] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[54]

On June 14, 2016, the Company filed its IRP for the plan year, June 1, 2016 to May 31, 2017 (2016-2017 IRP). A technical conference was held on June 23, 2016, to discuss the 2016-2017 IRP with regulatory agencies and interested stakeholders. Primary topics of discussion included the Company's study on heat pumps and peak-hour issues. On August 15, 2016, the Office filed its IRP comments.[55] The Division submitted its report and recommendation on August 15, 2016.[56] On September 30, 2016, the Company filed its Reply Comments.[57]

On December 1, 2016, the Utah Commission issued its Report and Order on the 2016-2017 IRP.[58] The Utah Commission recognized the Company's efforts in preparing its annual IRP, managing the IRP process, and addressing Commission guidance from previous Utah Commission orders. Specifically, the Commission stated that the Company's efforts ensure that the "annual IRP provides timely, valuable information on its plans for meeting its present and future responsibilities." The Utah Commission also acknowledged that integrated resource planning is an ongoing process and should be adjusted to reflect changing circumstances. In its conclusion, the Utah Commission agreed with the Division that the 2016-2017 IRP as filed complied with the requirements of the 2009 IRP Guidelines.

In its IRP comments filed on August 15, 2016, the Office made the general recommendation that the Company continue to monitor the potential future effects of heat pumps. With respect to peak day and peak hour demand, the Office recommended 1) that the Company "implement new cost-effective DSM programs that help to alleviate peak day and peak hour system constraints," and 2) "If energy efficiency increases peak day and peak hour demand, include the costs of mitigating these problems in the cost-benefit analysis for this type of DSM program." In its September 30, 2016 Reply Comments, the Company agreed with the

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[53] "In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines," Report and Order on Standards and Guidelines for Questar Gas Company, Docket No. 08-057-02, Issued: March 31, 2009.

[54] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Report and Order, Docket No. 09-057-07, Issued: March 22, 2010.

[55] Memorandum titled, "Questar Gas Company's 2016 IRP, Docket No. 16-057-08," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Bela Vastag, Utility Analyst, Gavin Mangelson, Utility Analyst, Danny A.C. Martinez, Utility Analyst, August 15, 2016.

[56] Action Request Response, To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Artie Powell, Manager, Energy Section, Doug Wheelwright, Technical Consultant, Carolyn Roll, Technical Consultant, Subject: Action Request Docket No. 16-057-08, Questar Gas Company 2016-17 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: August 15, 2016.

[57] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2016 to May 31, 2017," Before the Public Service Commission of Utah, Questar Gas Company's Reply Comments, Docket No. 16-057-08, September 30, 2016.

[58] In the Matter of Questar Gas Company's Integrated Resource Plan (IRP) for Plan Year: June 1, 2016 to May 31, 2017, The Public Service Commission of Utah, Report and Order, Docket No. 16-057-08, Issued: December 1, 2016.

conclusions made by the Office, but disagreed with many of the statements underlying those conclusions. In its December 1, 2016 Report and Order, the Utah Commission encouraged the Company "to continue to monitor and report on the heat pump trends in its jurisdiction and their impacts on peak demand and cost recovery." With regard to the potential DSM impact on peak demand, the Commission directed the Natural Gas DSM Advisory Group, the Company, the Office, and the Division to "explore potential DSM initiatives with the hope of reducing peak demand." A discussion of these issues is contained in the Energy-Efficiency Programs Section of this report.

Periodically, workshops and meetings are held in the IRP process to respond to specific issues, as ordered by the Utah Commission, to receive input for the IRP process or report on the progress of the Company's planning effort. On August 8, 2016, the Commission held a meeting during which the Company updated the Utah Commission on information pertaining to the cost-of-service gas produced by Dominion Energy Wexpro for the Company, specifically: the five-year forward curve, cost-of-service gas production, and field management issues.

On February 1, 2017, the Utah Commission held a confidential IRP workshop in conjunction with the development of the 2017-2018 IRP. The attendees discussed the following topics:

- Merger Integration Update
- Review of the Utah Commission's 2016 IRP Order
- Review of the Utah IRP Standards and Guidelines
- Discussion of the January 6, 2017 Weather Event
- Results of the 2016 Appliance Survey
- Gas Quality Issues

On February 27, 2017, the Company sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 10, 2017.

The Utah Commission held another confidential workshop on February 28, 2017 with Utah regulatory agencies. The attendees discussed the following topic:

- Gas Supply, Storage, and Transportation Planning

On March 23, 2017, an IRP workshop was held where the following topics were discussed:

- Excess Flow Valve Update
- Contracting Update
- LNG Storage Facility Options

On April 20, 2017, Utah regulatory agencies met to discuss the following topics and related confidential information:

- Merger Update
- Contracting Update
- Review of the Company’s 2016 RFP for purchased gas
- Review of the 2016-2017 Heating Season (IRP vs. Actual)
- Dominion Energy Wexpro’s Drilling Plan

The Company welcomes discussion and open dialogue and will schedule additional technical conferences to answer questions and resolve any remaining issues. The Utah Commission has scheduled a technical conference for June 27, 2017, to discuss the 2017-2018 IRP with Utah regulatory agencies and interested stakeholders.

During the course of the IRP process, the Company has maintained four main goals and objectives:

1. To project future customer requirements;

2. To analyze alternatives for meeting customer requirements from a distribution system standpoint, an upstream capacity standpoint, a gas-supply source standpoint, a reliability standpoint, and taking into consideration the inter-day load profile of each source;

3. To develop a plan using stochastic data and methods, and risk management programs that will provide customers with the most reasonable costs over the long term that are consistent with reliable service, stable prices, and are within the constraints of the physical system and available gas supply resources; and

4. To use the guidelines derived from the IRP process as a basis for creating a flexible framework for guiding day-to-day, as well as longer-term gas supply decisions, including decisions associated with cost-of-service gas, purchased gas, gathering, processing, upstream transportation, and storage.

The Company utilizes a number of models as part of its IRP processes. The complexity of the systems being analyzed necessitates the use of computer-based tools. Modeling tools are an integral part of the forecasting, gas network analysis, energy-efficiency analysis, and resource selection processes. In each section of this report where the Company has referred to modeling tools, the IRP contains a description of the functions of each model and the version utilized. The IRP also contains discussion of any material changes (logic and data) from the previous year’s IRP including the reasons for those changes.

An annual IRP process coincides well with the natural cycles of the gas industry. Some of the end-of-calendar-year data is not available and fully analyzed for IRP purposes until mid-April. The utilization of this information ensures the Company is including the most current and relevant information in its IRP. The required data input assumptions utilized in IRP models are voluminous. Nevertheless, the intent of this IRP is to summarize, in a readable fashion, the Company’s planning processes.