INTRODUCTION AND BACKGROUND

In recent months, an increasing number of business combinations have occurred in the mid and downstream energy sectors. On February 1, 2016, Dominion and Questar (the parent company of Questar Gas), announced an agreement to combine the two companies. Dominion has agreed to purchase the outstanding shares of Questar stock in an all cash deal valued at approximately $4.4 billion. The transaction is expected to close near the end of 2016 pending required approvals. In the words of Thomas F. Farrell II, chairman, president and chief executive officer of Dominion, "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 is headquartered in Richmond, Virginia, with utility and retail energy customers in 14 states. Dominion and Questar have similar businesses, similar corporate cultures and shared values. Dominion has been in the natural gas business for over a century. The combined company will serve approximately 2.3 million natural gas utility customers, operate more than 15,500 miles of natural gas transmission, gathering and storage pipelines, and own one of the nation's largest natural gas storage systems. On the electric side, Dominion serves 2.5 million utility customers and owns approximately 24,300 MW of electric generation. Dominion has also recently committed approximately $1 billion to three solar projects in Utah.[3]

Dominion has agreed to maintain Questar Gas' corporate headquarters in Salt Lake City, Utah. The Company's new name will be "Dominion Questar Gas." Salt Lake City will become the operating headquarters of Dominion's Western Region.[4]

In filings submitted to the Utah and Wyoming Commissions, Dominion has committed to operate Dominion Questar Gas in the same manner as it is operated today. The intent of the merger is to position Dominion Questar Gas for growth rather than to place emphasis on cost reductions. The merger will not result in changes to any existing filed rates. The Company will continue to engage in the IRP processes and follow the Utah and Wyoming Commissions' guidelines after the merger closes.[5]

For the second consecutive year, J.D. Power recognized Questar Gas for having the highest ranking among utilities in the Western region in its 2016 Gas Utility Business

[2] "Dominion Resources, Questar Corporation to Combine," Richmond, Va., PRNewswire, February 1, 2016.
[3] "Questar Corporation and Dominion Resources to Combine," Questar Corporation, News Release, Salt Lake City, Utah, February 1, 2016.
[4] Id.
[5] "In the Matter of the Joint Notice and Application of Questar Gas Company and Dominion Resources, Inc. of Proposed Merger of Questar Corporation and Dominion Resources, Inc.," Before the Public Service Commission of Utah, Docket No. 16-057-01, March 3, 2016.
"In the Matter of the Joint Application of Questar Gas Company and Dominion Resources, Inc. for Approval of Proposed Merger of Questar Corporation and Dominion Resources, Inc.," Before the Public Service Commission of Wyoming, Docket No. 30010-150-GA-16, March 3, 2016.

Customer Satisfaction Study. J. D. Power used six factors to determine customer satisfaction (in order of importance): safety and reliability, billing and payment, corporate citizenship, customer service, price, and communications. Not only did Questar Gas have the highest index score in the Western Region, but its score of 789 represented the highest point total across all regions.

During 2015, the Utah Historical Society awarded Questar Gas its annual Outstanding Achievement Award. Questar Gas received the award for its efforts in protecting and preserving an ancient site discovered during excavation work associated with a pipeline replacement project in Dimple Dell Park located in the southeast quadrant of Salt Lake County, Utah.

Over the previous IRP year, the topics of greatest interest related to the natural gas industry revolved around a natural gas leak at a storage facility, the continued decline of commodity prices and environmental issues.

A natural gas leak occurred at the Aliso Canyon underground storage facility near Porter Ranch, California. Southern California Gas Co. (SoCal Gas) owns this facility and it is among the largest of its kind in the U.S. with 86 Bcf of working gas capacity. On February 11, 2016, SoCal Gas reported the leak had been stopped, and one week later, reported the well had been permanently sealed and taken out of service.[6] In early April of 2016, the Obama administration announced the creation of a task force to investigate the Aliso Canyon natural gas leak. The task force will provide a report to Congress in October of 2016 on how the leak happened and how future leaks can be prevented.[7]

There has also been significant national dialogue in recent months regarding the Clean Power Plan. On June 2, 2014, the U.S. Environmental Protection Agency (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 is expected to increase natural gas-fired generation, and, to a lesser extent, renewable generation such as solar, wind, tidal and geothermal. Natural gas combustion, compared with coal, emits only 56% of the CO_2, 19% of the carbon monoxide, 20% of the nitrogen oxides, 0.04% of the sulfur dioxide, 0.26% of the particulates, and none of the mercury. It was also expected that demand-side efficiency measures would be expanded under the draft rule.[8]

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 its 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 at the

[6] "State Regulators Confirm Aliso Canyon Well is Permanently Sealed," SoCal Gas News Release, Los Angeles, California, February 18, 2016.
[7] "Obama announces task force to investigate Aliso Canyon gas leak," by Eric DuVall, Los Angeles, California, UPI, April 2, 2016.
[8] http://www.natfuel.com/natural_gas_environment.aspx

expense of natural gas.[9] 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 three-judge panel from the U.S. Court of Appeals for the D.C. Circuit was expected to hear oral arguments in this case in early June of 2016.[10] On May 16, 2016, the D.C. Circuit ordered this case be heard by the full Court and rescheduled oral argument for September of 2016.[11] Regardless of the outcome of the Clean Power 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.[12]

During 2015, power generators retired more electric generating capacity than in recent years (approximately 18 GW). Of that amount, more than 80% of retired plants were fired by conventional steam coal. These were typically older and smaller units. The coal capacity retired in 2015 was about 4.6% of the total U.S. coal capacity at the beginning of the year.[13]

During the month of April, 2015, U.S. generation of electricity fueled by natural gas exceeded coal fired generation for the first time since the Energy Information Administration (EIA) began keeping data. The EIA predicted that 2016 would be the first year that natural-gas-fired generation would exceed coal generation in the U.S. on an annual basis.[14] The EIA expects that additions of utility-scale generating capacity to the power grid during 2016 will total to more than 26 GW, based on reported additions and retirements, not model projections. Of the total additions, 9.5 GW consist of solar, 8.0 GW consist of natural gas, and 6.8 GW consist of wind.[15]

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[9] "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.
[10] "Supreme Court puts the brakes on the EPA's Clean Power Plan," The Washington Post, Jonathan H. Adler, February 9, 2016.
[11] "Clean Power Plan to get unanticipated en banc review," The Washington Post, Jonathan H. Adler, May 16, 2016.
[12] "Generators reshape portfolios, despite CPP stay," Gas Daily, Platts McGraw Hill Financial, February 11, 2016, Pages 6 and 7.
[13] "Coal made up more than 80% of retired electricity generating capacity in 2015," Today in Energy, U.S. Energy Information Administration, March 8, 2016.
[14] "Natural gas expected to surpass coal in mix of fuel used for U.S. power generation in 2016," Today in Energy, U.S. Energy Information Administration, March 8, 2016.
[15] "Solar, natural gas, wind make up most 2016 generation additions," Today in Energy, U.S. Energy Information Administration, March 1, 2016.

Recent EIA data indicates that energy related CO_2 emissions in the U.S., during calendar year 2015, totaled 5.27 billion metric tons, a decline from the 2014 level of 5.41 billion metric tons. Energy related CO_2 emissions peaked in 2007 at a level of 6.00 billion metric tons. The 2015 level is more than 12% below the 2007 level.[16] The general decline from 2007 is largely attributed to the weak economy, 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 eight years.[17]

Federal Energy Regulatory Commission (FERC) has focused recently on environmental matters. The FERC regulates 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 Questar Gas. The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate.

Several changes have taken place in the composition of the FERC over the last IRP year. During May of 2015, Phillip Moeller, a FERC Commissioner since 2006, announced his plans not to seek reappointment for a third term. Commissioner Moeller's term expired on June 30, 2015, and he stepped down in October of 2015. The loss of Commissioner Moeller left the FERC with four members: three Democratic and one Republican.

In January of 2016, Commissioner Tony Clark, the remaining Republican, announced that he would not seek a new term. His term runs through June of 2016, although he could extend his departure date to later in the fall. The FERC can, if necessary, operate as a quorum with three members of the same party. Commissioner Clark has been an outspoken critic of the disruptive tactics of certain environmental protesters who had interrupted Commission meetings and of those who, as he put it, took an uncompromising "NOPE" (not on planet earth) advocacy position on all natural gas infrastructure issues.[18]

Over the past year, the FERC has been faced with mounting opposition in the form of legal challenges, protesters and increasing criticism. Among the issues expected to be on the FERC agenda over the next year are the Clean Power Plan, power price formation, gas-electric coordination, growing obstacles to infrastructure development and the recovery of pipeline safety costs. FERC Chairman Norman Bay, commented on the fuel neutrality of the agency and remarked, "I think FERC has very prudently viewed itself as being an economic regulator, not an environmental one. When you look at the Federal Power Act, for example, its very language speaks to that economic role as . . . giving us the obligation to ensure that rates remain just and reasonable. While the EPA has a very important mission, FERC has an important mission as well, and so I would not regard us as being the drivers for environmental policy."[19]

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[16] "April 2016 Monthly Energy Review," U.S. Energy Information Administration, U.S. Department of Energy, Released: April 26, 2016.
[17] "U.S. energy-related carbon dioxide emissions in 2015 are 12% below their 2005 levels," Today in Energy, U.S. Energy Information Administration, May 9, 2016.
[18] "Looking for new challenges, Clark to leave FERC," Gas Daily, Platts McGraw Hill Financial, January 25, 2016, Pages 8-9.
[19] "Clean Power Plan stay won't halt broader industry trends: FERC chairman," By Paul Ciampoli, American Public Power Association, From the February 17, 2016 issue of Public Power Daily, Originally published February 16, 2016.

In addition to the environment, the continuation of low energy prices has been prominent in the national energy dialogue. 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 December of 2015, the average monthly Henry Hub price had declined to a low of $1.93 per Dth. On March 4th, of 2016, the Henry Hub daily price hit a low of $1.49 per Dth, the lowest daily price since 1998.

Regional prices at the Opal, Wyoming hub have also been weak in recent months. On March 5, 2016, the average daily mid-point price at Opal was $1.28, the lowest since September 3, 2008.

In recent months the Henry Hub natural gas futures forward curve had prices in the low $2.00 per-Dth range through the summer months of 2016. Those prices are expected to rise gradually through the end of the 2016-2017 heating season to the low $3.00 per Dth range. The 36-month strip, which has been in contango in recent months, has flattened out with a number of future winter-heating-season months also in the low $3.00 per Dth range.

In spite of low natural gas prices, production has remained strong. During 2015, total natural gas production averaged approximately 79 Bcf/D, a record high level. This level was approximately 5% greater than in 2014.[20]

Interestingly, since 1900, three fossil fuel sources, coal, petroleum and natural gas, have combined to total in excess of 80% of the U.S. fuels mix. In recent years, coal and petroleum have declined as natural gas has increased. Even with recent declines in total U.S. fossil fuel energy consumption, these fuel sources will likely combine to maintain a substantial share of the total U.S. energy mix for some years to come.[21]

Low natural gas prices continue to have 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 on two occasions reached 1,606 rigs. By May 20, 2016, the gas-directed rig count had dropped to an all-time low of 85 rigs.[22]

The low energy price environment of 2015 continued to affect the profitability of natural gas and oil exploration and production companies. These companies were hurt, not only by low commodity prices, but also by hedges expiring during the year. These hedges were put in place to protect against the downside of low prices. As capital expenditure programs were cut, credit rating agencies continued to downgrade exploration and production

[20] "U.S. natural gas production reaches record high in 2015," Today in Energy, Energy Information Administration, U.S. Department of Energy, April 15, 2016.
[21] "Fossil fuels have made up at least 80% of U.S. fuel mix since 1900," Today in Energy, Energy Information Administration, U.S. Department of Energy, July 2, 2015.
[22] "North America Rig Count Current Week Data," Baker Hughes, http://www.bakerhughes.com/, May 2, 2016.

companies. Industry consultant Graves and Company estimated that world-wide job losses in the energy sector exceeded one quarter of a million during 2015.[23] According to the law firm of Haynes and Boone, from the beginning of 2015 through April 3, 2016, 59 North American oil and gas producers filed for bankruptcy. These cases involve approximately $19 billion in cumulative secured and unsecured debt. Haynes and Boone expect more producer bankruptcy filings during the remainder of 2016.[24]

During November of 2015, the EIA released its annual report on natural gas proved reserves for the prior calendar year. On November 23, 2015, the EIA reported that U.S. proved reserves of natural gas for 2014 set a new record of 388.8 Tcf. This level was 34.8 Tcf higher than the 2013 level, an increase of nearly 10%. The EIA anticipated that 2015 end-of-year reserves would decline due to lower prices, curtailed drilling and marginal operating economics.[25]

Total U.S. discoveries during 2014 totaled 50.5 Tcf, approximately 93% of which were extensions to existing natural gas fields. By source, the 50.5 Tcf discovered in 2014, can be broken down as 0.4 Tcf from coalbed methane formations (0.8%), 37.8 Tcf from shale formations (74.9%), and 12.3 Tcf from conventional and other tight formations (24.4%). Texas has the largest proved natural gas reserves, followed by Pennsylvania and Oklahoma. During 2014, West Virginia added enough proved reserves from the Marcellus formation to surpass Wyoming to become the state with the fourth largest proved natural gas reserves.[26]

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 during the period from November 2014 to November 2015 dropped very slightly from 4,665 Bcf to 4,658 Bcf. Since November 2013, total working-gas design capacity has been relatively flat. For the second consecutive year, no new storage facilities initiated operations in the U.S. For the year prior to November 2015, ten storage facilities became inactive and 12 existing facilities expanded operations.[27]

The traditional injection season ends at the end of October. During the fall of 2015, unusually warm weather and natural gas production growth led to continued injections in the early weeks of November. For the week ending November 20, 2015, national working gas storage volumes set a new all-time record high of 4,009 Bcf.[28] The traditional 2015 injection season was the second highest on record with net injections of 2,475 Bcf. By comparison, net injections for the 2014 traditional injection season totaled 2,753 Bcf.[29] By the end of the 2015-2016 traditional withdrawal season, on April 1, 2016, the lower-48 inventory level stood at

[23] "More job cuts expected for oil workers in 2016," Nathan Bomey, USA Today, January 8, 2016 (4:30pm).
[24] "Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, April 4, 2016.
[25] "U.S. proved oil and natural gas reserves rise in 2014,"Press Release, Energy Information Administration, U.S. Department of Energy, November 23, 2015.
[26] "U.S. Crude Oil and Natural Gas Proved Reserves, 2014," U.S. Energy Information Administration, U.S. Department of Energy, November, 2014. Components do not add to totals due to independent rounding.
[27] "Underground Natural Gas Working Storage Capacity," Energy Information Administration, U.S. Department of Energy, Release Date: March 16, 2016.
[28] Ibid.
[29] "Table 9. Underground natural gas storage – by season, 2014 – 2016," Natural Gas Monthly, Energy Information Administration, U.S. Department of Energy, March 2016.

2,480 Bcf, a new all-time record by a narrow margin. This level was 1,008 Bcf higher than the same time last year and was 874 Bcf or 54.4% above the five year average.[30]

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

Both environmental issues and low commodity prices are having an effect on the growth of natural gas interstate pipeline capacity. In addition to meeting residential loads, new interstate pipeline capacity will, in the future, provide for; 1) growing natural-gas-fired electric generation, 2) growing industrial and commercial loads (particularly methanol and fertilizer plants) seeking to capitalize on low commodity prices, and, 3) takeaway capacity in regions of the country where production has been growing rapidly. However, natural gas interstate pipeline developers have been challenged recently on multiple fronts.

As of March 30, 2016 five proposed "greenfield" pipeline projects in the northeast were expected to go in-service by 2017, but none have received FERC approval to proceed. Out of seven major "brownfield" projects with originally scheduled with an in-service date in 2017, only Constitution Pipeline has received FERC approval, and that project is facing new delays from state regulatory agencies.[31]

During 2015, U.S. natural gas pipeline companies lost a substantial portion of their market valuations. Although these companies are selling transportation services and not energy commodities, the stock prices of these energy-related entities were hurt by association with the downturn affecting the commodity side of the industry. Declining market valuations effect credit ratings and ultimately the cost of debt for interstate pipeline companies.

Additional pipeline capacity will be needed to serve liquefied natural gas (LNG) export terminals. During February of 2016, the departure of the vessel "Asia Vision" from the Sabine Pass LNG facility near the Texas/Louisiana border marked the beginning of large-scale, modern-tanker LNG export from the lower 48 states. Cheniere Energy Partners owns the Sabine Pass facility. Though this event enjoyed some fanfare, it was not the first U.S. LNG export. In fact, "[i]n January 1959, the world's first LNG tanker, the Methane Pioneer (a converted World War II Liberty freighter) carried liquefied natural gas from Lake Charles, La., to Canvey Island, United Kingdom . . . The Methane Pioneer subsequently carried seven additional LNG cargoes to Canvey Island."[32]

With the growth in U.S. natural gas production in recent years, interest in LNG exports has increased. The EIA reports that four additional LNG export terminals are currently under construction: Dominion Energy's Cove Point facility in Maryland, Cheniere's Corpus Christi facility in Texas, Sempra Energy's Cameron terminal in Louisiana, and Freeport LNG's

[30] "Weekly Natural Gas Storage Report," Energy Information Administration, U.S. Department of Energy, For the week ending April 1, 2016, Released April 7, 2016.
[31] "Rover pushes back proposed in-service date," Gas Daily, Platts McGraw Hill Financial, Pages 3 & 4, March 30, 2016..
[32] https://www.dom.com/corporate/what-we-do/natural-gas/dominion-cove-point/history-of-lng

facility in Texas. As of March, 2016, 21 LNG export facilities had been proposed to the FERC. Of those proposals, 8 are pending applications and 13 are projects in the pre-filing phase.[33]

The proposed Jordan Cove LNG export facility on the Oregon coast is of particular interest to Questar Gas because the addition of this facility could impact prices in the area. 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 Questar Gas' northern service territory. Questar Gas 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.[34] 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.[35] 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.[36]

Questar Gas further discusses its use of interstate pipeline capacity and its interest in LNG liquefaction and LNG storage facilities in the Gathering, Transportation and Storage section of this document.

Interest in the use of natural gas as a vehicle fuel has diminished in the past year due to the continued decline in the price of gasoline at the pump, which is currently within $0.50 of the posted price of compressed natural gas (CNG). As of April 2016, there are 1,600 existing CNG stations nationwide and another 150 planned. Utah still remains in the top five U.S. States of CNG Infrastructure according to NGVAmerica (see Figure 2.1).[37] For information regarding the location of Questar Gas CNG stations refer to Exhibit 2.1.

[33] "Growth in domestic natural gas production leads to development of LNG export terminals," Today in Energy, Energy Information Administration, U.S. Department of Energy, March 4, 2016.
[34] "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.
[35] "Jordan Cove in offtake deal with JERA," Gas Daily, Platts McGraw Hill Financial, March 24, 2016, Pages 6 and 7.
[36] "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.
[37] https://www.ngvamerica.org/stations/

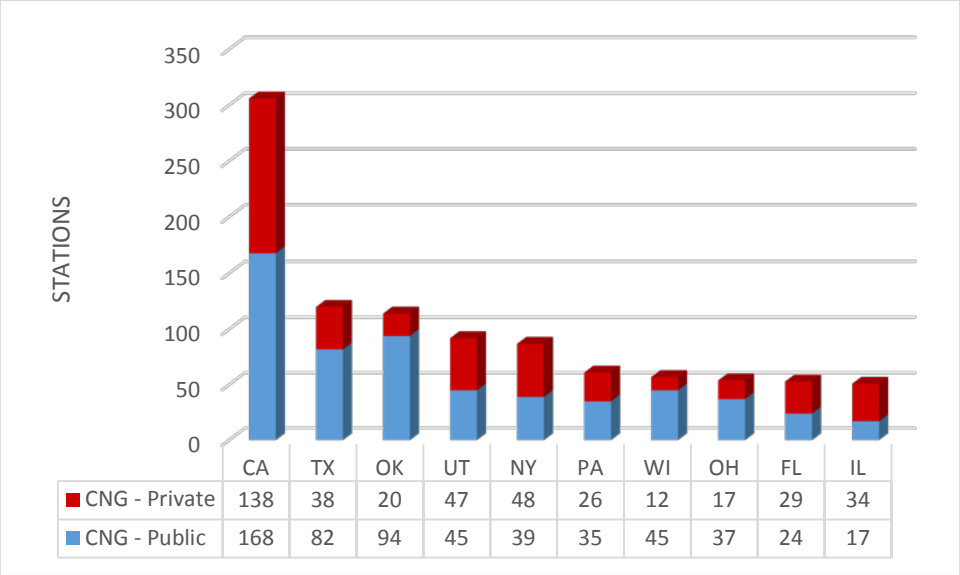

Figure 2.1 - Top Ten U.S. States: CNG Infrastructure (Feb 2016)

Class 8, over-the-road CNG vehicle platforms continue to grow and both refuse hauler and cement trucks are beginning to take hold in the marketplace These are more "behind the fence" on-site fueling solutions, while utilizing Questar Gas' public fueling infrastructure as a back-up to their respective activities.

Public usage of Questar Gas' CNG system has grown over time. However, CNG usage at Questar Gas' stations experienced its first decline in 2015 due to the decline in the price differential between CNG and gasoline. As gasoline prices remain low, Questar Gas will likely experience similar declining usage throughout 2016.

The increase in shale gas production has focused attention on the environmental impacts of hydraulic fracturing. In its Fiscal Year 2010 budget report, the U.S. House of Representatives Appropriation Conference Committee identified the need for another study of the environmental impacts of hydraulic fracturing. Congress tasked EPA scientists with carrying out the study. 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.[38]

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,

[38] "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.

a fracturing chemical registry where well-specific chemical disclosures can be made.[39] Approximately 110,000 well sites have been registered with FracFocus. Wexpro Company (Wexpro), Questar Gas' 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. The SAB criticized the EPA draft report for: 1) not releasing its findings in specific areas where contamination has been alleged, 2) determining findings inconsistent with the data, 3) not clearly incorporating the risk and probability of contamination and 4) for not providing more comprehensive information on the toxicological effects of the chemicals used in hydraulic fracturing.[40]

The Independent Petroleum Association of America (IPAA) disputed 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. The IPAA cited eleven peer-reviewed studies supporting its challenge. Its letter to the EPA was signed by 50 energy-related organizations.[41]

The American Petroleum Institute (API) also disputed the SAB's report by citing the Department of Energy: "More than 4 million oil and gas related wells have been drilled in the United States since development of these energy resources began nearly 150 years ago. At least 2 million of these have been hydraulically fractured, and up to 95% of new wells drilled today are hydraulically fractured, accounting for more than 43% of total U.S. oil production and 67% of natural gas production." The API continues, "The industry drills and hydraulically fractures thousands of oil and natural gas wells each year and there is simply no evidence of widespread or systemic contamination. There are reasons no such widespread or systemic contamination exists: namely the widespread and systemic application of proven engineering technologies and industry risk management practices, coupled with a complex web of federal and state regulatory regimes."[42]

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,

[39] FracFocus is operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.
[40] "Science panel disputes EPA fracking finding," Gas Daily, Platts McGraw Hill Financial, January 8, 2016, Pages 10 & 11.
[41] 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.
[42] 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.

Utah and Wyoming, and the Ute Indian Tribe all joined in the petition. In response to the petition, U.S. District Judge Scott Skavdahl, on September 30, 2015, issued a preliminary injunction blocking the implementation of the BLM rules and agreeing with the petitioners that the BLM had overstepped its jurisdiction. IPAA President Barry Russell commented, "Today's decision is consistent with IPAA's position that BLM's efforts are not needed and that states are – and have for 60 years been – in the best position to safely regulate hydraulic fracturing." While the matter is being resolved, applications with the BLM have been processed under pre-existing regulations.[43]

Wexpro II Agreement and Gas-Producing Property Acquisitions

Over the course of approximately 35 years, Questar Gas' customers have benefited from supplies delivered at cost-of-service to the Company pursuant to the Wexpro Agreement.[44] Beginning in the fall of 2011, Questar Gas and Wexpro and regulatory agencies in Utah and Wyoming began discussing the possibility of Wexpro acquiring oil and gas properties or undeveloped leases for the mutual benefit of Questar Gas' customers and 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 (also referred to now as the Wexpro I Agreement).

On March 28, 2013, the Utah Commission issued its Report and Order approving the Company's Wexpro II Agreement[45] and on October 16, 2013, the Wyoming Commission issued its Order approving the Wexpro II Agreement.[46]

The Utah Commission held a hearing on the Trail Unit Acquisition on January 8, 2014, and on January 17, 2014 issued a Report and Order approving the Settlement Stipulation allowing the Trail Unit Acquisition to be included under the Wexpro II Agreement.[47] The Wyoming Commission held a hearing on January 27, 2014 and issued a bench order approving the Settlement Stipulation. The Wyoming Commission issued a written Order approving the Settlement Stipulation on March 18, 2014.[48]

On December 19, 2014, Questar Corporation announced that Wexpro had acquired an additional interest in the Canyon Creek Unit, a natural-gas producing property, for

[43] "Court ruling delays BLM fracking rule implementation on federal land," Gas Daily, Platts McGraw Hill Financial, October 1, 2015, Page 5.
[44] For more information on the Wexpro Agreement, see the Cost-of-Service Gas section of this report.
[45] 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.
[46] 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.
[47] "In the Matter of the Application of Questar Gas Company for Approval to Include Property Under the Wexpro II Agreement," Utah Public Service Commission, Docket No. 13-057-13, Report and Order, Issued: January 17, 2014.
[48] "In the Matter of the Application of Questar Gas Company for Approval to Include Property Under the Wexpro II Agreement," Public Service Commission of Wyoming, Docket No. 30010-134-GA-13 (Record No. 13720), Issued March 18, 2014.

approximately $52.5 million. The Canyon Creek Unit is in southwestern Wyoming in the Vermillion Basin and has 100 producing wells. Though the Company already owned working interests in Canyon Creek, the Canyon Creek acquisition increased Wexpro's ownership interest from 70% to 100% and added 40 Bcf equivalent of net proved-developed reserves. Wexpro has identified 35 additional well locations which can be developed in the future.[49]

As these acquired properties are within the footprint of the Wexpro I Agreement, they were offered to the Utah and Wyoming Commissions on August 31, 2015, for inclusion under the Wexpro II Agreement. During September and early October of 2015, technical conferences were held in Utah and Wyoming to discuss and provide information to regulatory agencies. On October 8, 2015, the Utah Division of Public Utilities (Division) and the Utah Office of Consumer Services (Utah OCS) filed direct testimony in the Utah docket. On October 13, 2015, the Wyoming Office of Consumer Advocate (Wyoming OCA) filed its direct testimony in the Wyoming Docket.

On October 26, 2015, Questar Gas, Wexpro Company, the Division, the Utah OCS and the Wyoming OCA, after reaching agreement, 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,[50] and on February 24, 2016 the Wyoming Commission issued its formal approval of the Stipulation.[51] In addition to adding the Canyon Creek acquisition as a cost-of-service property under the Wexpro II Agreement, the Stipulation provided a number of other modifications to the Wexpro agreements. These modifications are described in more detail in the Cost-of-Service Gas section.

The Wexpro II Agreement and subsequent settlement stipulation provide a framework whereby Questar Gas' customers can continue to receive the long-term benefits of cost-of-service production. Questar Gas believes that the Wexpro II Agreement will be valuable to customers over the long term in Wyoming and Utah.

Wyoming IRP Process

Questar Gas 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.[52] 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

[49] News Release, Questar Corporation, "Questar Subsidiary Wexpro Announces Acquisition," December 19, 2014.
[50] "In the Matter of the Application of Questar Gas Company for Approval of the Canyon Creek Acquisition as a Wexpro II Property," Utah Public Service Commission, Docket No. 15-057-10, Order Approving Stipulation, Issued: November 17, 2015.
[51] "In the Matter of the Application of Questar Gas Company for Approval of the Canyon Creek Acquisition as a Wexpro II Property," Public Service Commission of Wyoming, Docket No. 30010-145-GA-15, Memorandum Opinion, Findings, and Order Approving Stipulation, Issued: February 24, 2016.
[52] "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.

filing of integrated resource plans, in some cases, and reviewing such plans."[53] On May 12, 2009, the Wyoming Commission approved Rule 253 and on January 24, 2011 the Wyoming Commission approved the natural gas IRP guidelines.[54]

Questar Gas filed its 2015 IRP on June 8, 2015, 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 November 24, 2015, Commission Staff issued a report on its review of the 2015 IRP. Commission Staff found no areas of concern with the results and projections in the 2015 IRP, and concluded, ". . . it is evident that Questar is actively identifying, evaluating and executing projects and plans to meet their obligation to maintain Wyoming services at safe and reliable levels."[55] The Wyoming Commission addressed Questar Gas' 2015 IRP in its Open Meeting on December 1, 2015. The Commission Staff recommended that the Wyoming Commission issue a letter order accepting the Company's IRP for filing. On December 2, 2015, the Wyoming Commission issued a letter order accepting the 2015 IRP for placement in the Commission's files.[56]

Shortly after taking office, Wyoming Governor Mead issued a directive asking state agencies to eliminate obsolete, unnecessary and duplicative rules. In response to this directive, the Wyoming Commission proposed changes to the rules and regulations affecting public utilities. The Commission held three technical conferences during April and May of 2015 where the proposed new rules were introduced and discussed. Wyoming Commission Rule 249 (Chapter 3 Section 26) and Rule 253 (Chapter 3 Section 33) are most relevant to the IRP process and govern the requirements for the filing of IRPs and their use as documentation for pass-on filings.

Since that time, multiple entities submitted comments on the proposed regulations to the Wyoming Commission. On December 4, 2015, Questar Gas submitted its comments on Chapter 3 of the proposed regulations.[57] On March 30, 2016, the Wyoming Commission issued

[53] 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).
[54] 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.
[55] Memorandum from Don Biedermann, Jess Bottom and John Burbridge to Chairman Minier, Deputy Chairman Russell and Commissioner Brighton; Re: Docket No. 30010-144-GA-15 (Record No. 14143) In the matter of the application of Questar Gas' Integrated Resource Plan (IRP) for Plan Year June 1, 2015 to May 31, 2016; November 24, 2015; Page 11.
[56] 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, 2015 to May 31, 2016 – Docket No. 30010-144-GA-15 (Record No. 14143), Issued: December 2, 2015.
[57] Correspondence from Jenniffer Nelson Clark, Senior Corporate Counsel, Questar Gas Company to Chris Petrie, Secretary and Chief Counsel, Wyoming Public Service Commission; Re: Public Notice of Intent to Revise Rules and Regulations Dated October 20, 2015; December 4, 2015.

a Public Notice indicating that chapters 1 through 5 were approved and were effective March 21, 2016.[58]

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.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Standards) to be effective starting with the Company's 2010 IRP.[59] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[60]

On June 8, 2015, Questar Gas filed its IRP for the plan year, June 1, 2015 to May 31, 2016. On August 12, 2015, the Office filed its IRP comments.[61] The Division submitted its report and recommendation on August 13, 2015.[62]

On October 22, 2015, the Utah Commission issued its Report and Order on the 2015 IRP.[63] 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. 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 2015 IRP as filed substantially complied with the requirements of the 2009 IRP Standards and Guidelines.

In its IRP comments filed on August 12, 2015, the Office commended the Company for the information provided in the 2015-2016 IRP with specific reference to the accuracy of the Company's demand forecasts over the past 14 years. The Office also commended the Company for its efforts in helping parties understand the cost-of-service production calculation.

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[58] Wyoming Public Service Commission Public Notice dated March 30, 2016; Certification Page Regular and Emergency Rules issued March 21, 2016 at 4:50 p.m.

[59] "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.

[60] "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.

[61] Memorandum titled, "Questar Gas Company's 2015 IRP, Docket No. 15-057-07," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Danny A.C. Martinez, Utility Analyst, August 12, 2015.

[62] 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. 15-057-07, Questar Gas Company 2015-16 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: August 13, 2015.

[63] In the Matter of Questar Gas Company's Integrated Resource Plan (IRP) for Plan Year: June 1, 2015 to May 31, 2016, The Public Service Commission of Utah, Report and Order, Docket No. 15-057-07, Issued: October 22, 2015.

The Office made two general recommendations for future IRPs in its report. First, the Office recommended the Utah Commission require the Company to continue to monitor the impact, if any, of DSM programs on peak-day usage and report the results. Second, the Office recommended the Utah Commission require the Company to include additional information about heat pumps in its next IRP. In its October 22, 2015 Order, the Utah Commission found these two recommendations reasonable and requested the Company provide the additional information in the 2016-2017 IRP. A discussion of the impact of DSM programs on peak day is contained in the Energy-Efficiency Programs Section of this report.

With regard to the heat pump study, the Office specifically requested; 1) an overview of how air and ground source heat pumps are used in space and water heating applications, both residential and commercial, 2) a description of the ambient temperatures that result in the efficient use of heat pumps along with the temperatures requiring a switch back to natural gas appliances, 3) a specific explanation of how the operations of heat pumps have the potential to impact peak demand and associated infrastructure along with gas management challenges, and 4) analysis demonstrating potential cost recovery and cross subsidies associated with heat pump customers. The Company's study is included in the Customer and Gas Demand Forecast 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 December 17, 2015, the Commission held a meeting during which Questar Gas updated the Utah Commission on changes that have occurred in the 2015-2016 IRP related to peak hour needs, infrastructure replacement and system capacity.

On February 24, 2016, the Utah Commission held an IRP workshop in conjunction with the development of the 2016-2017 IRP. The attendees discussed the following topics:

- The Dominion/Questar Announcement
- Review of the 2015 Commission IRP Order
- IRP Standards and Guidelines
- Ryckman Creek Storage Update
- Meeting Peak-Hour Demands

On February 29, 2016, Questar Gas sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 11, 2016.

The Utah Commission held a workshop on April 6, 2016 with Utah regulatory agencies. The attendees discussed the following topics:

- Heating Season Review
- Wexpro Cost-of-Service Reporting
- Wexpro Drilling Plan
- Upstream Transportation Contracts

On May 4, 2016, Utah regulatory agencies met to discuss the following topics and related confidential information:

- Review of the Questar Gas 2016 RFP for purchased gas
- Update on Peak-Hour services RFP
- IHP Pressure Telemetry

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 23, 2016, to discuss the 2016-2017 IRP with Utah regulatory agencies and interested stakeholders.

During the course of the IRP process, Questar Gas 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 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.