INTRODUCTION AND BACKGROUND

Over the past IRP year, a precipitous drop in oil prices was the most pivotal event within the energy complex. From September 2014 to January 2015 the prices of the three major benchmark crudes dropped by approximately 50% (West Texas Intermediate, Brent and Dubai). For decades, Saudi Arabia, with its enormous production capability, has controlled world oil prices by periodically playing the role of swing producer. On November 27, 2014, the Organization of the Petroleum Exporting Countries (OPEC) met in Vienna, Austria, where Saudi Arabia blocked appeals from several OPEC members for production cuts. Consequently, market forces continued exerting downward pressure on world oil prices. This current OPEC policy determination has effectively forced higher-cost producing countries, including the U.S., to balance the world oil, market thereby becoming the new swing producers.[2]

The current surplus of oil has its roots in the development of two technologies that were first used to improve recoveries of natural gas. Hydraulic fracturing and directional drilling have dramatically increased the production of shale gas over the last decade. In recent years, these two technologies have been utilized similarly in oil plays resulting in extraordinary recoveries of crude.[3] In 2014, crude oil production in the U.S., including lease condensate, increased by 1.2 million barrels per day over 2013, a 16.2% increase. This volumetric increase was the largest since production data was first recorded in 1900.[4]

The price of oil has direct implications for natural gas markets. Over one half of all hydrocarbon drilling produces a combination of both oil and gas. On an energy-equivalent basis, oil is much more valuable than natural gas. Because of this disparity, the decision to drill is often driven by the prospects for recovering oil, not natural gas. And, because natural gas liquids are priced relative to oil, exploration and production (E&P) companies have an incentive to drill in fields where the natural gas stream is wet with hydrocarbon liquids, as opposed to drilling in drier fields. As the price of oil and natural gas liquids decline, cutbacks in drilling will inevitably reduce levels of associated natural gas production that would have been produced otherwise.

Many energy analysts agree that Saudi Arabia's refusal to cut oil production is part of a long-term strategy designed to drive marginal E&P companies out of business, thereby setting the stage for future price increases. While the worst is likely yet to come, layoffs and bankruptcies have already begun in the U.S. E&P sector. Credit rating firms have reported a sharp increase in default rates. Consequently, the credit profile of the energy sector has deteriorated substantially in recent months.[5]

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[2] "Who Will Rule the Oil Market?," Daniel Yergin, The New York Times, Sunday Review Opinion, January 25, 2015, Page SR6.
[3] Ibid.
[4] "U.S. Oil Production Growth in 2014 Was Largest in More Than 100 Years," Today in Energy, U.S. Energy Information Administration, March 30, 2015.
[5] "Fitch Sees Sharp Rise in E&P Default Rates," Gas Daily, Platts McGraw Hill Financial, March 30, 2015, Page 1.

Predictably, E&P companies have decreased their planned capital budgets. The U.S. Energy Information Administration (EIA) statistics published in the fourth quarter of 2014 show the beginning of this trend. On a year-over-year basis, upstream capital expenditures for international oil and gas companies declined by 12% during the fourth quarter.[6] It has not been uncommon for U.S. E&P companies to announce capital-spending cuts of 30-50% for 2015. On the positive side, drilling and well service costs have declined as E&P companies have focused more intensely on driving down completed well costs.

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 was during August and September of 2008 when the peak on two occasions reached 1,606 rigs. By April 17, 2015, the gas-directed rig count had dropped to an all-time low of 217 rigs, approximately 86% below the high. The last time prior to 2015 that the gas-directed rig count dipped close to this level was in June 1992 when the weekly rig count dropped to a level of 242 rigs.[7]

Despite weakening natural gas prices and a declining rig count, U.S. marketed natural gas production reached a record-high average level of 79.2 Bcf per day for the month of December 2014. For the year 2014, marketed natural gas production was approximately 6.2% higher than the year 2013. This was the strongest annual growth rate since 2011.[8] Strong production in the face of a declining rig count is attributed to well optimization technologies such as directional drilling, hydraulic fracturing and multi-well pad drilling.

Another factor affecting natural gas markets is the exportation of liquefied natural gas (LNG). Plentiful supplies of moderately-priced natural gas have prompted a number of new proposals for LNG export facilities. In October 2014, the EIA published a report evaluating three export scenarios: 12 Bcf/D, 16 Bcf/D and 20 Bcf/D over a 25-year timeframe. The EIA concluded that, relative to its AEO2014-Reference-case baseline, projected residential natural gas prices in the lower-48 states could be expected to increase by approximately 2% in the 12 Bcf/D LNG export scenario ranging up to approximately 5% in the 20 Bcf/D export scenario.[9]

In the shorter term, the lack of California hydropower could also increase demand for natural gas. The California Department of Water Resources reported that as of April 8, 2015, snowpack water content statewide was just 8% of average.[10] Since the California drought began in 2011, reductions in hydropower output have largely been offset by increased natural-gas fired power generation.

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[6] "Upstream Capital Expenditure Declined 12% Year-Over-Year in Fourth-Quarter 2014," Today in Energy, U.S. Energy Information Administration, U.S. Department of Energy, March 25, 2015.

[7] "North America Rig Count Current Week Data," Baker Hughes, http://www.bakerhughes.com/, May 26, 2015.

[8] "Table 7. Marketed Production of Natural Gas in Selected States and the Federal Gulf of Mexico, 2010-2015," Natural Gas Monthly, U.S Energy Information Administration, U.S. Department of Energy, March 2015.

[9] "Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets," U.S. Energy Information Administration, U.S. Department of Energy, October 2014.

[10] "Daily Drought Information Summary (04/09/2015)," California Department of Water Resources, California Data Exchange Center, Report generated: 04/09/2015 13:05.

Each December, the EIA releases a report on natural gas proved reserves for the prior calendar year. On December 4, 2014, the EIA reported that U.S. proved reserves of natural gas for the U.S. for 2013 reached a record all-time high level of 354 Tcf. This level was 31.3 Tcf higher than the 2012 level, an increase of approximately 10%. Total U.S. discoveries during 2013 totaled 53.0 Tcf, approximately 96% of which were extensions to existing natural gas fields. By source, the 53.0 Tcf discovered in 2013, can be broken down as 0.3 Tcf from coalbed methane formations (0.6%), 37.2 Tcf from shale formations (70.2%), and 15.6 from conventional and other tight formations (29.4%). As would be expected, due to the development of the prolific Marcellus play, Pennsylvania and West Virginia reported the largest net increases at the state level in natural gas proved reserves. The third and fourth largest state increases were Texas and Wyoming respectively.[11] Although definitive proved reserve data for 2014 is not yet available, the credit rating agency Fitch expects natural gas reserve growth for U.S. producers to continue into 2014 due to "a tailwind from higher average natural gas prices."[12]

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. Power plants are the largest source of carbon pollution in the U.S. 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. The EPA plans to issue final rules for existing, new, modified and reconstructed power plants during the summer of 2015. If the rule becomes final, states must submit compliance plans by the summer of 2016.[13] Compliance to the rule is expected to increase natural gas-fired generation, and, to a lesser extent, renewable generation such as solar, wind, tides and geothermal. It is also likely that demand-side efficiency measures will be expanded.

Recent data from the EIA indicate that energy related CO_2 emissions in the U.S., during calendar year 2014, totaled 5.40 billion metric tons, a slight increase over the 2013 level of 5.37 billion metric tons. The 2014 increase over 2013 was driven by higher total energy use driven by the cold temperatures during the first six months of the year.[14] Energy related CO_2 emissions peaked in 2007 at a level of 6 billion metric tons. The 2014 level is nearly 10% below the 2007 level.[15] The general decline from 2007 is largely attributed to the weak economy, improving energy efficiency, 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 that general decline over the last seven years.

[11] "U.S. Crude Oil and Natural Gas Proved Reserves, 2013," U.S. Energy Information Administration, U.S. Department of Energy, Release Date: December 4, 2014. Components do not add to totals due to independent rounding.

[12] "Decent 2014 Reserve Replacement Expected Despite Oil Drop," Fitch Wire, Fitch Ratings Inc., January 5, 2015 (12:05pm).

[13] "Clean Power Plan & Carbon Pollution Standards Key Dates," U.S. Environmental Protection Agency, January 7, 2015.

[14] "Colder Weather Drives Forecast of 2014 Energy-Related CO_2 Emissions 1.1% Above 2013 Level," Today in Energy, U.S. Energy Information Administration, Department of Energy, October 30, 2014.

[15] "March 2015 Monthly Energy Review," U.S. Energy Information Administration, U.S. Department of Energy, Released March 26, 2015.

Current indications are that natural gas will be moderately priced for the foreseeable future. In recent weeks the Henry Hub natural gas futures forward curve had prices through the summer and fall shoulder months of 2015 in the upper two-dollar-per-Dth range. Henry Hub futures prices rise during the winter of 2015-2016 to the low three-dollar-per-Dth range. The 36-month strip generally rises over time, although none of the prices currently are over four dollars per Dth.

Questar Gas relies on interstate natural gas pipelines to deliver supplies to its city gates. Interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC). The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate. No more than three Commissioners may belong to the same political party and the President designates one Commissioner to serve as Chair.

A number of changes have taken place in the composition of the FERC over the last IRP year. On July 29, 2014, Acting Chairman Cheryl LaFleur was sworn in for a second term with the FERC. Acting Chairman LaFleur was named Chairman of the FERC on July 30, 2014. On August 4, 2014, Norman Bay was sworn in as a new Commissioner. Collette Honorable was also sworn in as a new Commissioner on January 5, 2015. Commissioner Bay was named Chairman of the FERC, effective April 15, 2015, with the previous Chairman, Cheryl LaFleur, continuing on as a Commissioner. On May 13, 2015 Phillip Moeller, a FERC Commissioner since 2006, announced his plans to not seek reappointment for a third term. Commissioner Moeller's current term expires on June 30, 2015.

The FERC will consider a number of key issues this year. Among those issues affecting the natural gas industry are: 1) gas-electric coordination (discussed in the Gathering, Transportation and Storage section of this report), 2) evaluation of the EPA's Clean Power Plan (discussed previously in this Introduction section), 3) the continuing review of proposed liquefied natural gas export terminals (discussed previously in this Introduction section), 4) enforcement, particularly with regard to market manipulation, and 5) cost recovery for modernization of natural gas facilities. On November 20, 2014, the FERC issued a proposed policy statement with the intent of providing greater cost-recovery certainty for interstate natural gas pipelines in complying with current and proposed federal safety and environmental regulations. The proposed policy statement discussed mechanisms such as trackers or surcharges that could be used to recover costs associated with infrastructure improvement enhancing efficient and safe operation of interstate pipelines. On April 16, 2015, the FERC issued a new policy allowing interstate natural gas pipelines to seek recovery of capital expenditures through a surcharge mechanism that enhances system reliability, safety and regulatory compliance. The policy is effective October 1, 2015.[16]

A recently recurring theme across the country has to do with the lack of interstate pipeline capacity needed for future natural-gas-fired electric generation. In the Rocky Mountain region, power generation relies heavily on coal. Bentek (a McGraw Hill Financial group) estimates that in 2014, the coal-fired portion of the total Rockies power burn averaged about 75%. With expectations for moderately-priced natural gas, and with the likely implementation of the Clean Power Plan, increased coal-to-gas switching could take place in

[16] "Cost Recovery Mechanisms for Modernization of Natural Gas Facilities," Federal Energy Regulatory Commission, Docket No. PL-15-1-000, Issued: April 16, 2015.

the future. Bentek expects that for 2014 and 2015, in the Rockies region, approximately 1,300 megawatts of coal generation will be retired. Bentek is forecasting an increased natural-gas power burn for the Rockies during the summer of 2015 over the prior five-year average.[17]

It is also apparent that competition for interstate pipeline capacity could intensify with the approval of LNG export terminals. On September 22, 2014, the developer of the Jordan Cove export terminal on the Oregon coast, Veresen Inc., announced that it had reached agreement to acquire a 50% interest in the Ruby Pipeline for approximately $1.43 billion. The Ruby Pipeline extends from the Opal Hub in Wyoming to the Malin Hub in Oregon and crosses Questar Gas' northern service territory. The Ruby Pipeline provides direct access to the Jordan Cove LNG facility through the proposed Pacific Connector Gas Pipeline.[18] The acquisition closed on November 6, 2014. Questar Gas further discusses its use of interstate pipeline capacity in the Gathering, Transportation and Storage section of this document.

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 2013 to November of 2014 changed from 4,664 to 4,665 Bcf. The EIA reported that no new natural gas storage facilities began operation over that time period. A slight increase in existing salt-facility capacity was largely offset by declines in non-salt facilities. In the West region, the working-gas design storage capacity over the same period of time changed from 804 to 807 Bcf. The EIA expects that growth in future natural gas storage design capacity will be relatively modest and will be primarily concentrated in salt facilities.[19]

During the winter of 2013-2014, much of the country experienced cold temperatures. This cold weather had a major impact on national natural gas storage withdrawals and inventories for the lower 48 states. According to the EIA, record setting withdrawals resulted in an 11-year record low inventory level of 822 Bcf by the end of the withdrawal season (end of March 2014). This level was 992 Bcf below the five-year average (54.7% below). At no time during the subsequent injection and withdrawal seasons, during calendar year 2014, did the lower-48 storage inventory level exceed the moving five-year average.[20]

The 2014 injection season proved to be record setting by the end of October. While not achieving the comparable inventory level reached in 2013 of 3,814 Bcf, net injections of 2,749 Bcf were made to reach a lower-48 inventory level of 3,571 Bcf on October 31, 2014.[21]

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[17] "Rockies Power Burn Hindered by Lack of Pipeline Infrastructure," Gas Daily, Platts McGraw Hill Financial, March 23, 2015, Page 5.
[18] "Canadian Pipeline Operator to Buy Western U.S. Natural Gas Pipe for $1.43 Billion," The Wall Street Journal, September 22, 2014.
[19] "Rise in Salt Cavern Storage Capacity for Natural Gas Offsets Declines in Other Capacities," Today in Energy, U.S. Energy Information Administration, February 26, 2015.
[20] "Weekly Natural Gas Storage Report for Week Ending February 13, 2015," Released February 19, 2015, U.S. Energy Information Administration, U.S. Department of Energy. Also, data was used from the accompanying historical tables.
[21] Ibid.

This inventory level did not exceed the moving five-year average inventory level until the week ending February 13, 2015.[22] By the end of the 2014-2015 withdrawal season on March 31, 2015, the lower-48 inventory level stood at 1,470 Bcf. This level was 180 Bcf or 11% below the five year average.[23]

During the month of February 2015, warm temperatures combined with transmission cuts due to the declaration of a force majeure on the Rockies Express Pipeline, caused record levels of working gas in storage in the Rocky Mountain region (Colorado, Utah, Wyoming and Montana), according to Bentek analysts at Platts, McGraw Hill Financial. This regional storage surplus resulted in short-term downward pressure on regional natural gas prices which could linger into the 2015 injection season.[24]

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

Interest in the use of natural gas as a vehicle fuel continues, however it is somewhat tempered by the current lower pricing of gasoline. During the past year, approximately 224 compressed natural gas (CNG) stations have been added to the nation’s infrastructure, bringing the total to over 1,514 with an additional 155 stations planned.

A number of Class 8, over-the-road CNG vehicle platforms have been added to the vehicle availability listing and refuse-hauler manufacturers continue to lead the charge by producing more factory-built CNG models than diesel or gasoline models. Independent kit manufacturers continue to make strides in offering additional CNG platforms for various medium & light-duty vehicles.

Congress once again allowed the $0.50 per gasoline-gallon equivalent (GGE) tax credit for fuel providers like Questar Gas. Though the credit was not in effect in 2014, Congress retroactively implemented it effective January 1, 2014 through December 31, 2014. The National Council of Weights & Measures is reviewing various proposals to define a diesel gallon equivalent (DGE) and a GGE in terms of pounds and convertible fuel equivalents, rather than in kilograms, as has been proposed over the past year. The industry has worked to oppose any migration to a kilogram standard from Weights and Measures. In addition, the Utah Weights and Measures Department has defined a GGE as 5.66 pounds of CNG and Questar Gas has adjusted its measurement standard accordingly.

Questar Gas is a national leader in the promotion of natural gas as a vehicle fuel. According to an NGV marketing study by TIAX, LLC published in February 2013, the Questar Gas service territory accounts for approximately 11,000 CNG vehicles (9% of the total CNG vehicles on the road today in the U.S.). Exhibit 2.1 is a map of the CNG station locations in Utah.

[22] “Natural Gas Inventory Exceeds Five-Year Average for First Time Since November 2013,” Today in Energy, U.S. Energy Information Administration, February 20, 2015.
[23] “Natural Gas Stocks Enter Injection Season 11% Below Five-Year Average,” Natural Gas Weekly Update, U.S. Energy Information Administration, U.S. Department of Energy, Release Date: April 9, 2015.
[24] “Record Storage Weighs Down Rockies Prices,” Gas Daily, Platts McGraw Hill, February 19, 2015, Page 1.

Questar Gas continues to install new public access CNG infrastructure facilities and to upgrade existing public access facilities as allowed by the Utah Commission.

Public usage of Questar Gas' CNG system has grown. Table 2.1 shows annualized GGEs for the past five years (based on approximately 127,000 Btus per gallon).[25]

Table 2.1

Year	GGEs	% Growth
2008	3,499,067	
2009	3,862,037	10.4%
2010	4,145,802	7.3%
2011	4,714,135	13.7%
2012	5,592,512	18.6%
2013	5,844,181	4.5%
2014	6,123,939	4.8%

During its 2015 General Session, the Utah Legislature passed several bills promoting the use of clean-burning natural gas. Utah House Bill 15 authorizes the Clean Fuels and Vehicle Technology Fund to make grants to individuals installing natural gas conversion equipment in eligible motor vehicles. It also extends tax credits for energy efficient vehicles. Utah House Bill 406 provides an income tax credit for the purchase of natural gas heavy duty vehicles (Category 7 or 8 vehicles as established by the Federal Highway Administration).

In recent years, the increase in shale gas production has focused attention on the environmental impacts of hydraulic fracturing.[26] 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. The EPA held public comment meetings in various locations around the country from July through September of 2010. The EPA released the first progress report in December of 2012. The progress report largely established the intent and methodological approach of the study, without articulating conclusions. 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 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.[27]

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[25] Going forward from January 2014, the BTU measurement value for CNG has changed. Based upon the Utah State Department of Weights and Measures requested change, Questar Gas will now measure GGEs at 5.66 pounds, which is approximately 135,000 ± BTUs per GGE.

[26] For a more detailed discussion of the benefits and risks of hydraulic fracturing, and the results of early studies by Federal agencies, see the Questar Gas Company, Integrated Resource Plan, For Plan Year: June 1, 2014 to May 31, 2015, Submitted: June 11, 2014, Pages 2-6 to 2-7.

[27] "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 have been made for over 12,000 wells.[28] Wexpro Company (Wexpro), Questar Gas' production affiliate, is among the companies voluntarily providing data to FracFocus.

On September 15, 2014, the Department of Energy National Energy Technology Laboratory released a report on hydraulic fracturing in Marcellus Shale gas wells in Pennsylvania. The study monitored six horizontal gas wells to determine if natural gas or fluids migrated from the hydraulically fractured Marcellus Shale to an overlying Upper Devonian/Lower Mississippian gas field during or after hydraulic fracturing. Four perfluorocarbon tracers were used to monitor migration. This study concluded that there was no detectable migration of gas or aqueous fluids to the upper formation during or after hydraulic fracturing. The Marcellus is more than 5,000 feet below drinking water aquifers.[29]

During December of 2014, the state of New York banned hydraulic fracturing becoming the second state in the Union to do so after Vermont. Although New York State has some recoverable reserves, its natural gas production is miniscule when compared with other states like Wyoming.

In light of these state bans, many in the industry still believe that states are in the best position to regulate and establish disclosure rules for the chemical components used in hydraulic fracturing fluids rather than federal agencies. The Wyoming Oil and Gas Conservation Commission was the first in the nation to implement a fracturing disclosure rule in 2010. During October of 2012, the Oil, Gas and Mining Board of the State of Utah approved a rule requiring disclosure within 60 days of hydraulically fracturing a well.

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. These rules, effective 90 days from issuance, generally require: 1) well integrity to be validated through the appropriate use of cement barriers between the wellbore and water zones penetrated by the wellbore, 2) public disclosure of chemicals through FracFocus, 3) standards for the storage of recovered waste fluids, and 4) the submission of data on pre-existing wells with the intent of lowering the risk of cross-well contamination.[30] Several organizations representing the exploration and production industry oppose the rules as burdensome and lacking cost justification.

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[28] FracFocus is operated by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.
[29] "An Evaluation of Fracture Growth and Gas/Fluid Migration as Horizontal Marcellus Shale Gas Wells are Hydraulically Fractured in Greene County, Pennsylvania," U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, September 15, 2014.
[30] "Interior Department Releases Final Rule to Support Safe, Responsible Hydraulic Fracturing Activities on Public and Tribal Lands," Bureau of Land Management News Release, U.S. Department of the Interior, Release Date: March 20, 2015.

On March 4, 2015, Questar Gas Company announced the completion of a transaction with Eagle Mountain City (Eagle Mountain) to purchase the city's municipal natural gas system. Eagle Mountain is in Utah County, Utah, west of Utah Lake and the city of Saratoga Springs. The municipal gas system serving Eagle Mountain is approximately 15 years old and includes nine miles of steel high-pressure pipeline and 158 miles of intermediate-high pressure main lines and service lines. Eagle Mountain has been one of the fastest growing cities in the state and currently has approximately 24,000 residents. Due to its size, Questar Gas brings operating efficiencies to this transaction. Eagle Mountain customers will be charged the same rates that are charged to all other similar Utah customers.[31]

Wexpro II Agreement and Gas-Producing Property Acquisitions

For over 30 years, Questar Gas' customers have benefited from supplies delivered at cost-of-service to the Company pursuant to the Wexpro Agreement.[32] 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[33] and on October 16, 2013, the Wyoming Commission issued its Order approving the Wexpro II Agreement.[34]

On September 4, 2013, Wexpro acquired an additional 42% interest in 72 producing wells in the Trail Unit, an area defined in the Wexpro II Agreement as a Development Drilling Area. On November 5, 2013, Questar Gas filed applications with the Wyoming and Utah Commissions seeking approval to include the Trail Unit Acquisition under the Wexpro II Agreement.[35]

On December 24, 2013, the Utah Division of Public Utilities (Division), the Utah Office of Consumer Services (Office), Questar Gas Company, the Wyoming Office of Consumer Advocate and Wexpro all agreed to the terms of a Settlement Stipulation.[36]

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[31] "Questar Gas Completes Purchase of Eagle Mountain City's System," Salt Lake City, Business Wire, March 4, 2015.

[32] For more information on the Wexpro Agreement, see the Cost-of-Service Gas section of this report.

[33] 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.

[34] 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.

[35] Wyoming Commission Docket No. 30010-134-GA-13, filed November 5, 2013. Utah Commission Docket No. 13-057-13, filed November 5, 2013.

[36] In Utah, the Settlement Stipulation was filed on December 24, 2013 in Docket No. 13-057-13. A Corrected Settlement Stipulation was filed on January 15, 2014, to correct a typographical error. In Wyoming, the Settlement Stipulation was filed on December 23, 2013, in Docket No. 30010-134-GA-13. The Corrected Settlement Stipulation was filed on January 16, 2014.

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.[37] 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.[38] On February 1, 2014, Wexpro recorded $103.7 million related to the Trail Unit Acquisition as a Wexpro II Property.

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 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 some 40 Bcf equivalent of net proved-developed reserves. Wexpro has identified 35 additional well locations which can be developed in the future. As these acquired properties are within the footprint of the Wexpro I Agreement, they will be offered to the Utah and Wyoming Commissions for inclusion under the Wexpro II Agreement.[39]

The Wexpro II Agreement provides a framework whereby the customers of Questar Gas can continue to receive the long-term benefits of cost-of-service production. Questar Gas is confident that the Wexpro II Agreement will prove to be valuable to its customers over the long term in Wyoming and Utah.

Wyoming IRP Process

Questar Gas has been involved in integrated resource planning for over two decades in the State of Wyoming. In 1992, the Wyoming Commission ordered the Company to prepare and file integrated resource plans.[40] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to integrated resource planning. The rule was proposed to ". . . give the Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[41] On May 12, 2009,

[37] "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.
[38] "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.
[39] News Release, Questar Corporation, "Questar Subsidiary Wexpro Announces Acquisition," December 19, 2014.
[40] "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.
[41] 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).

the Wyoming Commission approved Rule 253 and on January 24, 2011 the Wyoming Commission accepted the natural gas IRP guidelines.[42]

Questar Gas filed its 2014 IRP on June 11, 2014 with the Wyoming Commission. After affording all interested parties notice and an opportunity to comment, the Wyoming Commission addressed Questar Gas' 2014 IRP in its Open Meeting on November 20, 2014. The Commission Staff recommended that the Wyoming Commission issue a letter order accepting the Company's IRP for filing. On November 25, 2014, the Wyoming Commission issued a letter order accepting the 2014 IRP for placement in the Commission's files.[43]

Since 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 regulations affecting public utilities. On March 6, 2015, the Wyoming Commission issued notice of three technical conferences to be held during April and May of 2015 where the proposed new rules will be introduced and discussed. Wyoming Commission Rules 249 and 253 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.[44]

The Wyoming Commission is currently revising Rules 249 and 253, among others. On April 8, 2015, April 29, 2015, and May 13, 2015, the Wyoming Commission held technical conferences to discuss the proposed new rules resulting from Governor Mead's directive. This endeavor, ensuring that rules are clear, concise and relevant, is a laudable undertaking for any organization.

Utah IRP Process

In recent years, 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.

[42] 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.
[43] Letter Order, To: Jenniffer R. Nelson, Senior 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, 2014 to May 31, 2015 – Docket No. 30010-137-GA-14 (Record No. 13881), Issued: November 25, 2014.
[44] "Notice of Commission Activity," Wyoming Public Service Commission, Issued: March 6, 2015.

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.[45] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[46]

On June 11, 2014, Questar Gas filed its IRP for the plan year, June 1, 2014 to May 31, 2015. On August 13, 2014, the Division submitted its report and recommendation,[47] and the Office filed its comments on the 2014 IRP.[48]

On October 8, 2014, the Utah Commission issued its Report and Order on the 2014 IRP.[49] 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. The Utah Commission concluded the 2014 IRP as filed substantially complied with the requirements of the 2009 IRP Standards and Guidelines.

In its IRP comments filed on August 13, 2014, the Office commended the Company on the information provided in the 2014 IRP and made six recommendations for future IRPs. On September 12, 2014, the Company filed Reply Comments responding to the Office's recommendations and agreeing to make certain recommended changes.[50] The Utah Commission, in its 2014 IRP Report and Order, approved the commitments set forth in Questar Gas' Reply Comments and issued some additional conclusions and guidance. The changes the Company proposed in its Reply Comments are listed below, along with citations for how these commitments have been met.

1. The Company will report on the impact of demand-side management programs on peak-day usage as required by the Commission. (The Energy Efficiency Programs section of this report contains discussion of this impact.)

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[45] "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.

[46] "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.

[47] 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, Utility Analyst, Subject: Action Request Docket No. 13-057-15, Questar Gas Company 2014-15 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: August 13, 2014.

[48] "Questar Gas Company's 2014 IRP, Docket No. 14-057-15," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Béla Vastag, Utility Analyst, Danny A.C. Martinez, Utility Analyst, August 13, 2014.

[49] In the Matter of Questar Gas Company's Integrated Resource Plan (IRP) for Plan Year: June 1, 2014 to May 31, 2015, The Public Service Commission of Utah, Report and Order, Docket No. 14-057-15, Issued: October 8, 2014.

[50] "In the Matter of the Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2014 to May 31, 2015," Before the Public Service Commission of Utah, Reply Comments, Docket No. 14-057-15, September 12, 2014.

2. Inspection results from transmission integrity management program (TIMP) and distribution integrity management program (DIMP) activities will be included or referenced in future IRPs. (The Integrity Management Plan Activities and Associated Costs subsection of the System Capabilities and Constraints section of this report contains a discussion of these issues.)
3. Actual TIMP and DIMP annual expenditures will continue to be provided to the Utah Commission, Division and Office. (The Company provides this information to all of the indicated parties on a monthly basis.)
4. The Company will explicitly show the cost-of-service (COS) gas production-percentage calculation and show clearly how the annual forecasted demand is derived in complying with the stipulated 65% level. (The Cost-of-Service Gas and the Customer and Gas Demand Forecast sections of this report contain a discussion of this information.)
5. The Company will expand upon the section on COS gas shut-ins. (The Cost of Service Gas section and in Appendix A of this report contain an expanded discussion of COS gas shut-ins.)
6. The Company will provide, in a 2015 public IRP meeting, a detailed explanation of the annual demand forecast used for the gas management plan agreed to in the Trail Unit Stipulation and will seek a shared understanding of the calculation with the Division and the Office. (Interested parties discussed this topic in a meeting held on December 15, 2014 and again in an IRP workshop held on February 9, 2015.)

The Utah Commission offered additional guidance, as set forth below.

1. Continue discussions on peak day issues in the DSM Advisory Group and in a 2015 public IRP meeting. (Peak day discussions took place in a DSM Advisory Group Meeting on March 24, 2015 and in a public IRP meeting on March 25, 2015.)
2. Meet with interested parties to document agreed-upon Trail Unit Stipulation definitions, formulas and other relevant issues. (Interested parties discussed this topic in a meeting held on December 15, 2014 and again in an IRP workshop held on February 9, 2015.)
3. Annotate the backup workpapers supporting Quarterly Variance Report Exhibits 10.1 and 10.2. (This requested information is under review and will be added to the Quarterly Variance Report, Exhibits 10.1 and 10.2.)
4. Present the underlying data for Exhibit 3.8 in future IRPs. (The underlying data is included in Exhibit 3.8 of this report.)

Questar Gas has scheduled workshops and meetings over the past year to respond to specific issues, as ordered by the Utah Commission, to receive input for the IRP process, and to report on the progress of the Company’s planning effort. On February 9, 2015, the Utah Commission held an IRP workshop in conjunction with the development of the 2015 IRP. The attendees discussed the following topics:

- The 2015 IRP Schedule
- The Utah Commission 2014 IRP Report and Order
- The events of December 30 and 31, 2014
- The demand forecast and the Trail Unit Settlement Stipulation calculation

On March 3, 2015, Questar Gas sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 13, 2015.

The Utah Commission held a workshop on March 25, 2015 with Utah regulatory agencies. The attendees discussed the following topics:

- Storage contract terms and expiration dates
- Clay Basin, Aquifer, and Ryckman storage contracts
- Transportation contract terms and expiration dates
- Transportation capacity needs
- Kern River Gas Transmission Company (Kern River), Williams Northwest Pipeline (Northwest Pipeline), Colorado Interstate Gas Company (CIG) and Questar Pipeline Company (Questar Pipeline) transportation contracts

On May 4, 2015, Utah regulatory agencies met to discuss the following topics and related confidential information:

- Heating season review
- Management of cost-of-service gas for the 2014 IRP year
- Storage usage of Clay Basin and the Aquifers
- Review of the Questar Gas 2015 RFP for purchased gas

The Utah Commission has scheduled a technical conference on June 24, 2015, to discuss the 2015 IRP with Utah regulatory agencies and interested stakeholders.

Over the previous year, the Company has participated in a number of Utah IRP meetings to address specific issues, as ordered by the Utah Commission. The Company welcomes discussion and open dialogue and will schedule additional technical conferences to answer questions and resolve any remaining issues.

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, stochastic 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 dovetails 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 that 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.