INTRODUCTION AND BACKGROUND

In recent years, the natural gas industry in the U.S. has undergone a remarkable transformation, unprecedented in the history of natural gas since the advent of welded-steel long-haul pipelines in the early 1900s. This transformation has occurred as a consequence of the availability of large volumes of natural gas contained in shale formations. Recent advances in two technologies have made these reserves economically feasible to produce. These technologies are directional drilling and hydraulic fracturing.

Improvements in directional drilling technology have provided the capability for drill bits to be guided horizontally through producing formations resulting in more perforations, greater flows, and increased reserves for each bore hole. Drilling cost efficiencies are also improved through directional drilling technology as multiple wells can be drilled from the same pad.

Much of the surge in shale gas production can be attributed to hydraulic fracturing. Hydraulic fracturing stimulates production from a natural gas formation by expanding existing fissures and creating new ones in the formation through the application of extremely high fluid pressures. Formation fractures are maintained through the injection of a proppant (such as grains of sand or ceramic material) into the formation. When the application of high fluid pressure is terminated, the proppant prevents the fissures in the formation from closing allowing shale gas that would otherwise be trapped in the formation to flow freely.

According to data from the Energy Information Administration (EIA), in the U.S. Department of Energy, U.S. shale gas annual production grew from 1999 to 2009 by a factor of ten. In 2009, natural gas from shale formations made up approximately 14 percent of the total U.S. natural gas supply or 3.28 trillion cubic feet (Tcf). Indications so far are that shale gas production in 2010 was approximately 4.87 Tcf. The EIA forecasts shale gas to make up 45 percent (12.0 Tcf) of a growing total U.S. supply by the year 2035.[1]

Shale gas production has grown so rapidly in recent years, that the EIA has consistently and significantly underestimated this resource. From its 2010 Annual Energy Outlook to its 2011 Annual Energy Outlook, the EIA more than doubled its estimate for technically recoverable unproved shale gas resource.

Over the past decade, the Barnett Shale play in Texas has provided the bulk of shale gas production. Many of the techniques utilized today in other shale formations were perfected in this play. In addition to the Barnett play, other major shale plays in the U.S. include the Marcellus in the Appalachian Basin, the Haynesville-Bossier in the Texas Louisiana Salt Basin, the Woodford in Oklahoma, and the Fayetteville in the Arkoma Basin of Arkansas. Of note is the fact that daily natural gas production from the Haynesville Shale play (5.5 billion cubic feet per day) recently exceeded the Barnett Shale, an indication of the

[1] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2011– Early Release, December 16, 2010, overview.fig01.data.xls.

potential of the Haynesville Shale. Some of the decline in Barnett-Shale gas production can be attributed to an increased focus on liquids in this play in the current low natural gas price environment.[2]

The implications of the shale gas boom are substantial and far reaching. Critics of natural gas in the past, while acknowledging its relative safety and clean burning characteristics, have argued that the long-term availability of supply is uncertain and prices are too volatile. The natural gas futures forward curve is a meaningful, albeit short term, indicator of the price and availability of this resource. The current eighteen-month Henry Hub forward curve is relatively flat, with prices in the mid-four-dollar-per-decatherm to low-five-dollar-per-decatherm range. The long term expectations of most natural-gas-industry experts are for adequate supplies at a competitive cost. In addition to lower fuel prices for consumers and industries, increased shale gas production also means that the industries relying on natural gas as a feedstock and electric power generators will see competitive costs.

The shale gas revolution has benefits beyond competitive prices. Foreign energy imports have long been a concern from the standpoint of security of supply. Having this vast energy resource available domestically minimizes the impact of potential supply disruptions resulting from geopolitical instability. Development of natural gas infrastructure translates into jobs. Royalties and production taxes create wealth for the owners of mineral rights and help fund public services. Natural gas is the cleanest burning of the fossil fuels. Net air quality benefits will occur to the extent that fuel substitution takes place with other fossil fuels that would not have taken place otherwise.

U.S. energy-related carbon dioxide emissions declined in 2008 and 2009 by a total of 10 percent due mostly to the U.S. economic downturn. Assuming no new climate change legislation, the EIA forecasts energy-related carbon dioxide emissions will not reach 2005 levels until 2027. On a per capita basis, emissions are expected to decline from 2005 to 2035 by an average of 0.8 percent per year. This decline is driven in part by expectations for the more efficient use of transportation fuels and higher prices for electricity. Over one-half of the U.S. electricity supply is generated from coal which has almost twice the carbon dioxide emissions of natural gas. The EIA believes that, from 2009 to 2035, the U.S. will become less carbon intensive as energy-related carbon dioxide emissions per dollar of gross domestic product decline by 42 percent.[3] As the U.S. economy struggles to get back on track, the political environment in Washington D.C. is such that climate change legislation reducing carbon emissions is most likely off the table for the remainder of this year.

Over the last two years, the crude oil-to-natural gas price ratio has been at its widest spread in some 20 years. In recent months, the spread has exceeded a 30 to 1 ratio.[4] Analysts have generally attributed the spread to world political turmoil and weakness in the

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[2] "Haynesville Surpasses Barnett as the Nation's Leading Shale Play," U.S. Energy Information Administration, Today I n Energy, March 18, 2011, www.eia.doe.gov/todayinenergy/detail.cfm?id=570.
[3] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2011– Early Release, December 16, 2010, Pages 9 and 10.
[4] This ratio is expressed in dollars per barrel of oil of Brent crude versus dollars per MMBtu of natural gas at Henry Hub.

U.S. dollar driving the price of oil up and to the vast amounts of domestic shale gas holding the prices of natural gas down.

Since June of 2009, the U.S. oil rotary rig count has grown steadily from below 200 rigs to the mid-800s currently, reflecting the pursuit of higher-priced oil. Since June of 2009, the U.S. gas rotary rig count has grown from below 700 rigs to a short-term peak in mid-August 2010 of nearly 1000 gas rigs. Since that time, the gas rig count has declined to below 800 rigs and is expected to continue to decline this year.[5] Some of the rigs are moving from dry-gas plays to more profitable liquids-rich gas plays.

Coincident with the onset of shale gas production has been interest in the development of additional natural gas storage capacity. Since 2007, applications for over 600 Bcf of capacity have been filed with the Federal Energy Regulatory Commission (FERC) most of which has been built. The FERC is currently reviewing additional projects totaling several hundred Bcf of capacity.[6]

Two new natural gas storage projects in the vicinity of the operations of Questar Gas are the Magnum Gas Storage Project (Magnum) and the Ryckman Creek Gas Storage Project (Ryckman). The Magnum project involves the construction and operation of a high-deliverability, multi-cycle salt cavern storage facility and a 61 mile connecting header pipeline to be located in Millard, Juab and Utah counties, Utah. Total working gas capacity for the Magnum project is expected to be 42 Bcf. The Ryckman project involves the utilization of a partially depleted oil field located approximately 25 miles southwest of the Opal Hub in southwestern Wyoming. Working gas capacity planned for the first phase of the Ryckman project is 19 Bcf. Additional information on the Magnum and Ryckman projects is contained in the Storage Issues section of this report.

Much of the value of any natural gas storage facility is fundamentally linked to the ability of that asset to be used for price arbitrage.[7] Ironically, increased shale gas production has lowered long-term prices and narrowed price volatility. New projects can be viable, however, depending on the location relative to interstate pipelines, the supply of competing storage capacity, and the underlying cost structure of the facilities (including cushion gas).

A casualty of increased shale gas production, at least for the near term, is the Alaska natural gas pipeline. Since the discovery of major reserves in the Prudhoe Bay in 1967, multiple projects with a variety of sponsors have been on the drawing board. A perennial component of the EIA's energy supply model, the pipeline was expected to be completed in 2023 in its 2010 Annual Energy Outlook reference case. Higher construction costs and low gas prices were cited by the EIA as its rationale for dropping the project from its 2011 reference case.[8]

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[5] "U.S. Rig Report," North American Rotary Rig Count, U.S. Oil and Gas Split, Baker Hughes Inc., March, 25, 2011.
[6] "Shale Gas Boom a Mixed Bag for Storage Operators," Platts Energy Trader, January 14, 2011, Page 11.
[7] Storage can also be used to provide required supply deliverability that otherwise would not be available.
[8] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2011– Early Release, AEO2011 Early Release Overview, December 16, 2010, Page 2.

Most of the new natural gas pipeline projects with 2011 in-service dates are in the southeast region of the U.S. In the west, the Bison Pipeline sponsored by TransCanada, started flowing in January of 2010. This 302 mile, 30 inch-diameter, 477 million-cubic-feet-per-day pipeline transports natural gas from the Powder River Basin of Wyoming to an interconnection in North Dakota with the Northern Border Pipeline System where supplies can be delivered to mid-West markets.

Just finishing construction in the west is the Ruby Pipeline Project (Ruby). The Ruby system extends from Opal, Wyoming to Malin, Oregon. The project, sponsored by El Paso Corporation, is comprised of 680 miles of 42-inch diameter natural gas pipeline with a design capacity of approximately 1.5 billion cubic feet per day. The most recently estimated capital cost is $3.55 billion, up from the original estimate of $3.0 billion. The expected in-service date of the Ruby pipeline is July of 2011. Because of the proximity of the Ruby pipeline to the facilities of Questar Gas, the Company requested that Ruby install a tap valve just north of Brigham City, Utah. Additional information on the Ruby Pipeline Project is contained in the System Capabilities and Constraints section and the Transportation Issues section of this report.

While it is always difficult to assess the precise impact of a new pipeline on the market, the completion of the Ruby pipeline will likely exert some upward pressure on Rockies natural gas prices. Most analysts believe that the underlying costs of Rockies gas flowing on Ruby will compete well with Canadian gas. Likewise, Ruby's direct access to the Malin Hub may have superior economics to more circuitous pipeline routes for Rockies gas flowing to west coast markets.[9]

With the recent surge in shale gas production, increased attention has been given to the environmental impacts of drilling for this resource. Of particular interest is the drilling technology of hydraulic fracturing which some allege has resulted in the contamination of drinking water.

Hydraulic fracturing has been used to stimulate production from oil and gas wells since the late 1940's and is closely monitored by state regulatory agencies. When the casing of an oil or gas well is cemented, formations containing drinking water are isolated from those producing hydrocarbons. These formations are typically thousands of feet apart. The consensus among geologists and reservoir engineers is that it is highly unlikely that contamination of drinking water supplies could take place through the migration of fracturing fluids through thousands of feet (in some cases miles) of highly compressed geologic formations. In 1995, the Administrator of the Environmental Protection Agency (EPA) wrote with regard to the enforcement of the Safe Drinking Water Act in Alabama, "There is no evidence that the hydraulic fracturing at issue has resulted in any contamination or endangerment of underground sources of drinking water (USDW) . . . Moreover, given the horizontal and vertical distance between the drinking water well and the closest methane gas production wells, the possibility of the contamination or endangerment of USDW's in the

[9] "Ruby's Impact Remains Question Mark For Gas Prices on West Coast, Once Pipeline Starts Flowing: Bentek," Platts Energy Trader, February 7, 2011, Page 1.

area is remote."[10] In 2004, the EPA conducted a study to assess the potential for contamination of underground drinking water from the injection of hydraulic fracturing fluids into coalbed methane (CBM) wells. In its final report, the EPA stated, "Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time."[11]

The U.S. House of Representatives Appropriation Conference Committee, in its Fiscal Year 2010 budget report, identified the need for another study of the environmental impacts of hydraulic fracturing. EPA scientists were tasked with the assignment of carrying out the study. Public comment meetings were held in various locations around the country from July through September of 2010. Initial study results are expected to be available by late 2012.

On May 5, 2011, the Secretary of the U.S. Department of Energy announced the formation of a group of environmental, industry and state regulatory experts who were charged with the task of making recommendations, "to improve the safety and environmental performance of natural gas hydraulic fracturing from shale formations – harnessing a vital domestic energy resource while ensuring the safety of our drinking water and the health of the environment." Consensus recommendations are expected within six months of the commencement of the advisory group.[12]

The natural gas industry maintains that there is no evidence that drinking water has been contaminated by the migration of hydraulic fracturing fluids through thousands of feet of geologic formations to shallower aquifers. Over one million hydraulic fracturings have taken place in North America without water supplies being polluted.[13] If there is any potential for contamination from hydraulic fracturing, it is much more likely to occur from the improper handling of fluids above ground before the fracturing process, or, after the fracturing process when produced fluids are being disposed of. Such surface spills can be quickly identified, stopped, contained and cleaned up before drinking water contamination can occur.

The recent earthquake and subsequent tsunami in Japan, with its tragic loss of life and property, could have a long-term influence on world energy markets in general and the natural gas market in particular. With little in the way of domestic energy resources, Japan, the fifth largest energy user in the world, has been reliant for its power generation needs on nuclear fuel (27 percent), coal (28 percent), natural gas (26 percent) and oil (9 percent). Prior

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[10] Correspondence, dated May 5, 1995, from Carol M. Browner, Administrator of the United States Environmental Protection Agency, to David A. Ludder, Esq., General Counsel, Legal Environmental Assistance Foundation, Inc.

[11] "Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing," U.S. Environmental Protection Agency, EPA 816-R-04-003, June 2004, Page ES-1. The acronym "USDW" refers to "underground sources of drinking water."

[12] "Secretary Chu Tasks Environmental, Industry and State Leaders to Recommend Best Practices for Safe, Responsible Development of America's Onshore Natural Gas Resources," Fossil Energy News Spotlight, U.S. Department of Energy, May 5, 2011, retrieved from www.fossil.energy.gov/ on May 6, 2011.

[13] American Petroleum Institute, Hydraulic Fracturing, April 8, 2011, http://www.api.org/policy/exploration/hydraulicfracturing/.

to the nuclear plant crisis, the Japanese government had planned to grow its nuclear power generation to account for 50 percent of its electricity generation by the year 2030.[14] While all forms of energy are inherently dangerous, the political fallout from the radiation leaks will undoubtedly be a prominent negative factor in the decision to construct more nuclear reactors in Japan (and potentially worldwide). Since a significant portion of Japan's coal generation capacity has also been damaged, it is anticipated that natural gas and oil will fill much of the power generation void. Fortunately, the liquefied natural gas (LNG) market is fairly flexible, and it is expected that LNG cargoes will be diverted and redirected to meet increased demand in Japan. Japan was already the world's largest LNG importer prior to the crisis. While worldwide demand for LNG will increase due to the events in Japan, imports to the U.S. were expected to be weak even before the earthquake/tsunami due to a growing LNG European market and to the increasing availability of low-cost shale gas supplies in the U.S.[15]

Beginning on April 20th of 2010, a disaster of a different type began to unfold in the Gulf of Mexico with the blowout of the BP Deepwater Horizon oil well drilled in the Macondo Prospect. In addition to personal injury and loss of life, the blowout resulted in the largest marine oil spill in the history of the petroleum industry. This three-month-long oil spill, estimated at millions of barrels, caused vast damage to marine habitat and to the beaches and wetlands of the Gulf Coast.

On May 27, 2010, the Minerals Management Service in the U.S. Department of the Interior, in response to the oil spill, issued a moratorium on all drilling operations in water over 500 feet deep in both the Gulf of Mexico and the Pacific Ocean. The drilling moratorium was effective May 30, 2010, and stopped work on 33 off-shore deepwater rigs in the Gulf.

The magnitude of the oil spill necessitated the establishment of a national commission to determine the causes of the spill and to recommend reforms for safer energy production. In summary, the national commission determined that the Macondo blowout could have been prevented. Causal factors of the blowout include; 1) a flawed design of the cement slurry used to seal the bottom of the well, 2) inadequate testing of the cement seal, 3) inadequate training of personnel, and 4) a failure in recognizing important signals of the impending blowout.[16]

On October 12, 2010, the deepwater drilling moratorium was lifted by the Secretary of the Interior. It was estimated by the federal government that some 8,000 to 12,000 jobs had been lost due to the moratorium.[17] Subsequent to the lifting of the moratorium, the Bureau of Ocean Energy Management, Regulation and Enforcement in the U.S. Department of the Interior announced, on December 13, 2010, new regulations on well casing,

[14] "Japan Depends Significantly on Nuclear Power to Meet its Electric Needs," Today in Energy, Energy Information Administration, March 17, 2011.
[15] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2011– Early Release, December 16, 2010, Page 8.
[16] "Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling," Report to the President, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, January 2011.
[17] Ibid, Page 152.

cementing, blowout preventers, safety certification, emergency response and worker training.[18]

Approximately 10 percent of U.S. natural gas production originates in the Gulf of Mexico. Estimates have been made that Gulf oil and gas operations create over 550,000 jobs and $90 billion in gross domestic product.[19] At this point in time, it is uncertain what the full long-term impact of the BP Deepwater Horizon oil well blowout will be on the contribution of natural gas supplies from the Gulf to consumers in the U.S.

Against the backdrop of high oil prices and increasing political unrest in North Africa and the Middle East, the Obama Administration released, on March 30, 2011, its "Blueprint for a Secure Energy Future" (Blueprint). This document outlines a three-pronged strategy to reduce America's dependence on imported oil; 1) develop and secure America's energy supplies, 2) provide consumers with choices to reduce costs and save energy, and 3) innovate our way to a clean energy future. Natural gas plays a role in all three prongs of this strategy.[20]

The Obama Administration is encouraging the development and production of domestic oil and natural gas. Acknowledging that U.S. natural gas production reached a thirty-year high in 2010, the Blueprint encourages the provision of incentives for the development of natural gas and encourages fuel switching from oil to natural gas. Among the incentives suggested are shorter lease terms, and rewarding rapid lease development with lease extensions, and discounting royalty payments for early production during the lease term.

In the area of reducing costs and saving energy, the Blueprint acknowledges the Administration's funding through the American Recovery and Reinvestment Act (Recovery Act) of cleaner public transit bus fleets using compressed natural gas (CNG). The Blueprint also cites the ENERGY STAR® program, the HOMESTAR® program, the Weatherization Assistance Program, and the BetterBuildings Program which experts estimate could save $100 million annually in utility bills for households and businesses.

In the area of clean energy innovation, the Administration proposes that clean energy credits should be issued for electric generation from combined-cycle natural gas plants that capture and store carbon dioxide. The Administration also cites the investment of some $5.8 billion by federal agencies in energy efficiency projects for federal buildings many of which utilize natural gas. The Blueprint referred to additional executive action to be taken that would ensure that the federal fleet is an example of efficient and clean fuels by requiring that 100 percent of fleet acquisitions by 2015 are alternative fuel vehicles.

[18] "BOEMRE Issues Guidance for Deepwater Drillers to Comply with Strengthened Safety and Environmental Standards," The Office of Ocean Energy Management, Regulation and Enforcement, U.S. Department of the Interior, News Release: December 13, 2010.
[19] "The Economic Power of Gulf Oil and Gas," James Diffley, October 13, 2010, http://dyn.politico.com/printstory.cfm?uuid=A6EE5592-A0DD-F24B-9F166574672D6E07.
[20] "Blueprint for a Secure Energy Future," The White House, Washington D.C., March 30, 2011.

Consistent with the call by the federal government for more natural gas vehicles (NGVs), the State of Utah has also made alternative fuel vehicles a component of its long term energy plan. On March 2, 2011, Utah Governor Gary Herbert released Utah's 10-Year Strategic Energy Plan. One of the eight strategies articulated in this document for meeting Utah's energy goals is the diversification of transportation fuels by augmenting Utah's fuel supply with nontraditional transportation fuels including natural gas.[21]

Questar Gas is a national leader in the promotion of NGVs. Utah currently has 96 NGV filling stations, 26 of which are public access stations. Nationally, there are some 930 NGV filling stations. The State of Utah has seen a 47 percent increase in refueling capacity over the last 12 months resulting in border-to-border stations on both a north-south axis and an east-west axis. Over the last few years, Questar Gas CNG demand, on an equivalent-gallon-of-gasoline basis, averaged between 300,000 and 400,000 gallons per month. The current Questar Gas pump price is approximately $1.27 per gallon equivalent.[22]

In addition, Questar Gas will construct 5 new CNG filling stations in 2011, as well as converting approximately 100 company vehicles to run on CNG. These projects were partially funded by the Recovery Act, administered by the U.S. Department of Energy. The Department of Energy has assigned Utah Clean Cities to administer the funds locally.

The winter of 2010-2011 will be remembered as one of the snowiest in recent memory. North America experienced the largest January snow cover since 1985, and numerous U.S. cities set new monthly snowfall records.[23] Frigid weather in the service territory of Questar Gas in early February resulted in a new natural gas delivery record. On February 1, Questar Gas delivered 1.19 million Dths of natural gas, the highest in its 82 year history. The Company also set a new hourly delivery record on this day.

During April of 2010, Questar Corporation (Questar), the parent company of Questar Gas, announced that it was considering spinning off its natural gas and oil exploration and production business to its shareholders.[24] On May 18, 2010, the Questar board of directors conditionally approved the spin-off and announced the name of the new independent, publicly-traded company as QEP Resources.[25] On June 30, 2010, the spin-off was formally completed.[26]

Following the spin-off, Questar remains an integrated natural gas company headquartered in Salt Lake City, Utah. The business units of Questar consist of Wexpro Company, Questar Pipeline Company (Questar Pipeline), and Questar Gas Company. QEP

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[21] "Energy Initiatives & Imperatives: Utah's 10-Year Strategic Energy Plan," Governor Gary R. Herbert, March 2, 2011, http://www.utah.gov/governor/docs/10year-stragegic-energy.pdf.
[22] Carl Galbraith, Director Questar Gas Company Business Development. March 3, 2011.
[23] NOAA National Climatic Data Center, State of the Climate: Global Snow & Ice for January 2011, published online February 2011, retrieved on March 31, 2011 from http://www.ncdc.noaa.gov/sotc/global-snow/2011/1.
[24] "Questar Considering Spin-Off of Exploration and Production Business," News Release, Questar Corporation, April 21, 2010.
[25] "Questar Board of Directors Conditionally Approves Spin-Off of Exploration & Production Business" News Release, Questar Corporation, May 18, 2010.
[26] "Questar Completes Spin-off of QEP Resources" News Release, Questar Corporation, July 1, 2010.

Resources is headquartered in Denver, Colorado. All of the benefits of cost-of-service production from Wexpro Company will continue to accrue to the customers of Questar Gas.

Energy markets have increasingly become more global over time. As world and national events affecting the natural gas industry unfold, Questar Gas, to the extent possible, incorporates these factors into its forecasting and planning processes. These processes occur within the Company on a daily, monthly, annual and multi-year basis.

Wyoming IRP Process

Questar Gas has been involved in integrated resource planning for nearly two decades in the State of Wyoming. As directed in an order issued by the Wyoming Commission in 1992, the Company has been required to prepare and file integrated resource plans.[27]

More recently, on February 3, 2009, the Public Service Commission of Wyoming 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."[28] The order initiated a formal proceeding to consider promulgating the following rule:

> Rule 253: Integrated Resource Planning
>
> Any utility serving in Wyoming required to file an integrated resource plan (IRP) in any jurisdiction, shall file that IRP with the Wyoming Public Service Commission. The Commission may require any utility serving in Wyoming to prepare and file an IRP when the Commission determines it is in the public interest. Commission advisory staff shall review the IRP as directed by the Commission and report its findings to the Commission in open meeting. The review may be conducted in accordance with guidelines set from time to time as conditions warrant.[29]

A hearing on the proposed rule was held in Cheyenne, Wyoming on May 12, 2009, where Questar Gas articulated the position that it was generally in agreement with Rule 253. After deliberations, the Wyoming Commission approved Rule 253 as noticed. Proposed IRP Guidelines were also issued with the Wyoming Commission Order. These guidelines were not part of Rule 253.

On June 7, 2010, the Wyoming Commission sent out natural gas IRP guidelines to natural gas utilities with a request for comments to be made on or before July 22, 2010. The

[27] "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.
[28] 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).
[29] Ibid.

Wyoming Commission indicated that these guidelines were not part of a rulemaking and were informal in nature.[30] Following the receipt of comments, the Wyoming Commission, on January 24, 2011, notified all Wyoming natural gas utilities that the natural gas IRP guidelines were accepted by the Commission at its open meeting of December 16, 2010.[31]

Subsequent to the filing of Questar Gas's 2010-2011 IRP in Wyoming in the latter part of May 2010, notice was issued by the Wyoming Commission that the document was available for review with written comments to be filed on or before August 2, 2010. During May of 2010, Questar Gas responded to questions posed by the Wyoming Commission Advisory Staff about its gas purchase contracting.

On December 2, 2010, a public meeting was scheduled with the Wyoming Commission, Commission Advisory Staff, and the Office of Consumer Advocate to receive a general update and review of several specific topics from the Company. Also in attendance at the meeting and presenting information was the Wexpro Hydrocarbon Monitor.[32] Among the topics reviewed were the Wexpro Agreement, Wexpro operations, and Company infrastructure improvements in the Kemmerer, Diamondville and Rock Springs areas. The Cost-of-Service Gas section of this report contains more information on the Wexpro Agreement. The System Capabilities and Constraints section of this report contains more information on Wyoming infrastructure improvements.

Utah IRP Process

Over the past few years in the State of Utah, new IRP standards and guidelines have been implemented. 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.[33]

Subsequent to the filing of the 2009 IRP, the Utah Commission issued an action request to the Division of Public Utilities (Division) on May 6, 2009, requesting that comments be provided on the adequacy of the 2009 IRP, both the plan and the process. In the action request, the Utah Commission acknowledged the "many changes and

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[30] Correspondence from The Public Service Commission of Wyoming; Alan B. Minier, Chairman; Steve Oxley, Deputy Chairman, and Kathleen "Cindy" Lewis, Commissioner; to Barrie McKay, Manager of State Regulatory Affairs, Questar Gas Company dated June 7, 2010.

[31] 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.

[32] The Wexpro Hydrocarbon Monitor (an independent hydrocarbon industry consultant) is established by the Wexpro Stipulation dated October 14, 1981, and is selected by the Utah Division of Public Utilities in conjunction with the Staff of the Wyoming Public Service Commission to review the performance of the Wexpro Agreement and to advise all parties.

[33] "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.

enhancements to the information provided" by Questar Gas in the 2009 IRP. This action request also asked for comments on changes, if any, that would be necessary for the 2009 IRP to meet the requirements of the 2009 IRP Standards, as if they had been in effect, thus testing the sufficiency of information going forward.[34] On May 11, 2009, the Utah Commission issued an order broadening the action request by inviting all interested parties to comment on the same matters.[35]

In response to the action request and the broader request for comments, documents were filed by the Division, the Office of Consumer Services (the Office), and the Company. On March 22, 2010, the Utah Commission issued an order providing guidance on Questar Gas' 2009 IRP and clarifying the requirements of the 2009 IRP Standards (Clarification Order).[36] For a number of issues, the remarks filed by the parties in response to the broader request for comments were so disparate that the Utah Commission directed the Company to include discussions of these matters in 2010 IRP meetings in an attempt to reach a consensus among all interested parties. Questar Gas has always welcomed such dialogue with the recognition that integrated resource planning is a continually evolving process.

The first IRP clarification meeting was held on June 2, 2010 where a number of topics were discussed including the following:

- Inclusion of the concept of risk in the goals and objectives.
- The breadth of "gas supply decisions" in the goals and objectives.
- The general layout of the report.
- Appropriate level for breaking-out load growth forecasting data.
- Range of weather conditions.
- How changes in the efficiency of "end-uses" will affect future loads.
- The System-Wide Gathering Agreement.
- Natural gas storage reservoirs.
- Transportation contracts.
- Producer Imbalances.

A technical conference was held on June 22, 2010, to discuss the modeling and planning provisions associated with the high pressure and intermediate high pressure systems of the Company. The following topics were presented:

- Intermediate High Pressure Geographic Information System (IGIS).
- High Pressure Mapping System – Arc GIS Pipeline Data Model (APDM)
- Steady-state and unsteady-state Gas Network Analysis (GNA) system models.
- Model validation, operational planning and contingency planning.

[34] "Action Request – Revised," From: Public Service Commission, Subject: Questar IRP; 09-057-07, May 6, 2009.
[35] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Request For Comments, Docket No. 09-057-07, Issued: May 11, 2009.
[36] "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.

On July 1, 2010, another IRP clarification meeting was held where discussion took place on the following topics with regard to their inclusion in future IRPs:

- Gas quality issues at QGC' city gates.
- Gas quality issues in regional producing basins.
- Level of breakout for lost-and-unaccounted-for gas.
- Developments in the LNG markets.
- Deep water natural gas drilling moratoriums.
- Potential restrictions on hydraulic fracturing.
- Important regulatory proceedings.
- Appropriateness of including estimated external costs.
- QGC's integrity management plans.
- Distribution-non-gas action plan.

A public meeting, devoted to a review of Wexpro operations was held in Utah on September 21, 2010. The Wexpro Hydrocarbon Monitor was in attendance and presented information along with representatives of Wexpro. Among the topics discussed were:

- History of natural gas and oil properties prior to the Wexpro Agreement.
- Provisions, terms and conditions of the Wexpro Agreement.
- Regulatory review of Wexpro Operations and Hydrocarbon Monitor reports.
- Historical natural gas production levels under the Wexpro Agreement.
- Costs per Dth of Wexpro categories of production.
- Numbers of wells and geographic locations.
- Wexpro organization.
- Historical and future drilling programs.
- Development of the Pinedale Field.
- Wexpro's comparative cost structure and savings for QGC customers.
- Industry trends and challenges.
- New technological developments enhancing reservoir interpretation.
- Utilization of core inventory and image logs.

On May 24, 2010 the Utah Commission requested that the Division review and comment on the 2010 IRP. The Division filed its comments on July 19, 2010.[37] On October 27, 2010 the Utah Commission issued an order on the Company's 2010 IRP.[38]

The Utah Commission found that the Company's 2010 IRP generally satisfied the requirements of the 2009 IRP Standards. In addition, the Utah Commission required that the Company: 1) include in future IRPs, a more detailed description of the models used to derive long-term forecasts of residential usage per customer and number of customers; 2) discuss

[37] The Public Service Commission of Utah, In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2010 to May 31, 2011, Report and Order, Docket No. 10-057-06, Issued: October 27, 2010.

[38] State of Utah, Department of Commerce, Division of Public Utilities, Correspondence to the Utah Public Service Commission, Subject: Action Request Docket No. 10-057-06, QUC 2010-11 IRP Report; July 19, 2010.

the relationship between avoided gas costs and IRP modeling in a future IRP meeting; 3) include five years of historical information in the peak demand forecast graph; 4) engage in formal and informal training on stochastic modeling; 5) address in a public meeting, the planned increase in Company-owned gas volumes given the costs of Company-owned gas relative to purchased gas; and 6) provide all relevant data to the Utah Commission given the change in the quarterly reporting schedule.

Additional technical conferences and meetings have been held, and are scheduled to be held, in 2011, to clarify the 2009 IRP Standards, to report on the 2011 IRP process and to comply with the Utah Commission's order on the 2010 IRP. On February 9, 2011, an IRP Kickoff Meeting was held in conjunction with the development of the 2011 IRP. Issues discussed include:

- 2011 IRP meeting schedule.
- Record sales on February 1, 2011.
- Overview of the SENDOUT modeling process.
- Production versus purchase considerations.
- The Ryckman natural gas storage project.

On February 23, 2011, Questar Gas sent out its annual RFP for natural gas purchases. Responses were due on March 8, 2011.

A public technical conference was held on March 9, 2011, with Utah regulatory agencies. A representative of Questar Pipeline Company was in attendance to present a gas quality update for Questar Gas and Questar Pipeline. Topics discussed included:

- Natural gas interchangeability and the Wobbe number.
- Wobbe setpoints and operating ranges.
- Historical gas quality data by geographic location.
- Gas quality trends and observations.
- Gas quality rulings by the Federal Energy Regulatory Commission.
- Lost-and-unaccounted-for gas.
- Distribution Integrity Management (DIMP) program elements.
- DIMP Action Plan and anticipated costs.
- Excess flow valves.

On April 14, 2011, a meeting with Utah regulatory agencies was held to discuss the following topics, some aspects of which were confidential:

- Storage issues.
- Responses to the Company's purchased-gas request for proposals.
- Purchased-gas modeling results and recommendations.
- Conditions giving rise to producer imbalances and the evolution of gas balancing.
- Current producer imbalance levels and recoupment history.
- Avoided cost definitions and modeling approach.
- ThermWise® Cost Effectiveness Model compared with the SENDOUT Model.

- Energy efficiency measure-level modeling versus program-level modeling.
- Review of the Company's Demand-Forecasting End-Use Model.
- Review of the Customer Forecast Model.

A public meeting has been scheduled for June 21, 2011, to discuss this IRP and the final IRP modeling results with Utah regulatory agencies and interested stakeholders.

Over the previous 12 months, the Company has participated in numerous 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. The Company believes that the in-depth discussion of highly technical and complex issues can more appropriately take place in a technical conference format where dialogue can take place with interested parties rather than in this summary IRP document which has a broader readership with more general interests.

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 seasonal 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 planning processes engaged in by the Company.

This report has been organized into the following sections: 1) Questar Gas's customer and gas demand forecast; 2) the capabilities and constraints of Questar Gas's distribution system; 3) the local market for natural gas, the purchased gas RFP, associated modeling issues, and price stabilization topics; 4) cost-of-service gas including modeling issues, producer imbalances and future development prospects; 5) gathering, transportation and storage; 6) energy-efficiency programs; 7) the final modeling results; and 8) the general planning guidelines to be used in the implementation of the IRP from June of 2011 through May of 2012.[39]

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[39] Throughout this report, "Dth" refers to decatherms, "MDth" refers to thousands of decatherms, "MMDth" refers to millions of decatherms, "Dth/D" refers to decatherms per day, "MDth/D" refers to thousands of decatherms per day, "Btu" refers to British thermal units, "MMBtu" refers to millions of British thermal units, "cf" refers to cubic feet, "Mcf" refers to thousands of cubic feet, "MMcf" refers to millions of cubic feet, "Bcf" refers to billions of cubic feet, "Tcf" refers to trillions of cubic feet, "Mcf/D" refers to thousands of cubic feet per day, "MMcf/D" refers to millions of cubic feet per day, "psi" refers to pounds per square inch, "psig" refers to pounds per square inch gauge, and "lf" refers to linear feet. "FL" refers to feeder line.