The Natural Gas Industry at a Glance

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Preface

This document is an updated version of the paper of the same title published in January 2008. At the time of the 2008 paper's writing, the U.S. natural gas situation was characterized as supply-constrained. High prices induced increased drilling, but that drilling yielded little addition to domestic supplies. The consensus of experts was that the country had no choice but to rely increasingly on foreign sources of gas in the form of liquefied natural gas (LNG) to close the gap between growing demand and constrained gas supplies from the U.S. and Canada. Many of the regulatory issues stemmed from tight gas supplies effectuating high and volatile wholesale prices.

The natural gas industry has seen a dramatic turnaround since 2008 with promising prospects that shale gas will supply the U.S. gas market for several decades at reasonable cost. Advances in technology in the form of horizontal drilling and hydraulic fracturing have made this development possible. The energy guru Daniel Yergin has called this development the biggest energy innovation of this century. The effect of shale gas on the U.S. and worldwide energy markets will be nothing short of remarkable. It will likely change the dynamics of geopolitics, including decreasing the demand for Russian gas and increasing LNG imports by European countries. With an abundance of domestic natural gas, the U.S. will be able to rely much less heavily on foreign sources of gas, such as LNG. Predictions of lower and more stable natural gas prices should increase the domestic demand for natural gas, especially in the electric power and transportation sectors as they face greenhouse gas regulations.

For state public utility commissions (PUCs), the optimistic future for natural gas compared with three years ago will mitigate some problems but pose new challenges. The last section of this document identifies issues that the author believes PUCs will face in the coming years and describes what expertise they will need to address them. They might, for example, have to make decisions about whether and how utilities should stimulate the development of natural gas vehicles in their service territories; they might also have to reevaluate utility energy-efficiency initiatives in view of a more abundantly supplied and lower-priced natural gas future, as well as reevaluate utility hedging strategies in an environment in which natural gas prices are more stable and predictable.

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Online Access

The reader can access this document on the Web at http://www.nrri.org/pubs/gas/NRRI_nat_gas_at_a_glance_rev_oct10-14.pdf.

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The Natural Gas Industry at a Glance

I. Some Basic Facts about Natural Gas[1]

Natural gas is a fossil fuel composed mostly of methane. It also contains other hydrocarbons (e.g., ethane and butane), as well as impurities. Natural gas is found in sedimentary rock formations, often alongside petroleum deposits.[2]

Natural gas comprises about 25 percent of the total energy consumed in the United States.[3] Natural gas is used for a variety of purposes: to heat homes and water, cook food, produce electricity, provide heat for industrial processes, fuel vehicles, and as a raw material to manufacture such products as fertilizer, plastics, and petrochemicals. About 60 percent of the homes in the U.S. use natural gas as the main heating fuel. Electric power producers and industrial customers are the largest users of gas; gas consumption for electricity generation has grown most rapidly since the early 1990s.[4] End users (residential, commercial, industrial, and electric power customers) in the U.S. spend about $150 billion per year on natural gas.

Natural gas burns more cleanly than the other fossil fuels (i.e., coal and oil). Many energy experts, including environmentalists, view natural gas as a "bridge fuel" between the present carbon-based economy and a future economy highly reliant on renewable energy and energy efficiency.[5] Since the recent euphoria began over shale gas, some industry observers

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[1] *See* the U.S. Energy Information Administration's hyperlink quick gas facts.

[2] Sometimes people confuse natural gas with gasoline. Gasoline is a mixture of flammable liquid hydrocarbons derived chiefly from crude petroleum and used mostly in internal-combustion engines.

[3] This percentage is based on the measure British Thermal Units. One study projects that this share of natural gas could almost double over the next two decades. *See* the MIT study *The Future of Natural Gas*. This increase is a result of the abundant domestic gas supplies and greenhouse gas regulations that restrict carbon dioxide emissions. The study warned that if regulations on carbon dioxide are extremely stringent, natural gas might lose market share to energy sources (e.g., renewable energy, nuclear power) that have a smaller or no carbon footprint.

[4] Almost 25 percent of electricity generation in the U.S. comes from gas-fired facilities.

[5] Higher usage of natural gas because of lower prices does not necessarily translate into lower carbon dioxide emissions. Although natural gas would replace some oil and coal (which are more carbon-dioxide intensive), lower natural gas prices might also displace energy sources that either have zero emissions or less emissions than natural gas. These sources include nuclear power and renewable energy.

have seen natural gas as a major long-term source of energy for both the electric power and transportation sectors.[6]

The production of natural gas in the U.S. occurs in different geographical locations, including the Gulf of Mexico, the Rockies, and the Southwest.[7] Texas is by far the largest U.S. producing state. Increasingly, gas produced in the U.S. will come from unconventional sources, such as shale gas.[8] The Energy Information Administration (EIA) projects that by 2035 shale gas will comprise about 25 percent of the natural gas produced domestically.[9]

In 2009, imports of gas comprised about 16 percent of the gas consumed in this country.[10] These imports mostly originated in Canada, with the remainder coming from countries (the largest being Trinidad) exporting liquefied natural gas (LNG) to markets around the world.[11] The federal government has substantially reduced its projections of LNG imports over the next several years from what they were three years ago. In 2007, the EIA projected a

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[6] As one industry group has noted: "We see natural gas as more than a bridge fuel…We see it as a sustainable long-term solution for the economy and the environment." (*See* Natural Gas Supply Association, *News*, October 12, 2010.)

[7] U.S. natural gas production represents about 20 percent of world production.

[8] Contrary to many people's perceptions, conventional gas has become the marginal source of gas production in the U.S. This means that at the margin, the cost of producing conventional gas exceeds the cost for unconventional sources, such as gas shale.

[9] This percentage is low compared to some other estimates. For example, IHS Cambridge Energy Research Associates has stated that shale gas could account for 50 percent of the U.S. natural gas supply by 2035. (*See* IHS Cambridge Energy Research Associates, *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda*, 2010, ES-1.) The largest shale gas deposits are located at the Marcellus Shale, which spans six states that include New York, Pennsylvania, and West Virginia.

[10] This compares with oil, where about 65 percent of the oil consumed in the U.S. comes from foreign countries.

[11] Existing LNG regasification facilities currently have the capacity to supply about 25 percent of the domestic demand for gas; these facilities are currently greatly underutilized and expect to be underutilized in the future. The U.S. has found it difficult to compete with other countries for LNG, and the abundance of low-cost shale gas has made LNG less competitive. Natural gas prices are lower in the U.S. than in most countries; other countries tie the price of natural gas to oil prices, which currently are much higher than the energy-equivalent price of natural gas in the U.S. In Europe, for example, natural gas prices link to low-sulfur residual fuel oil. FERC has approved several LNG regasification facilities, most of which analysts expect not to go into service. For a background on LNG and recent activities, the reader can go to FERC LNG and NARUC LNG.

more than sevenfold increase of LNG imports between 2006 and 2025. It projected that by 2025 LNG will supply about 17 percent of U.S. gas needs. In its latest long-term ("reference case") projections, it predicted that LNG will supply less than 6 percent of U.S. gas needs in 2025 and less than 4 percent by 2035.[12] The same EIA study showed that total gas imports will decline to 6 percent of the gas consumed in this country. In other words, the U.S. will see domestic gas supplies growing by more than the demand for gas, meaning we will become less reliant on foreign sources of gas.[13] This dramatic shift is a result of the development of new technologies (namely, horizontal drilling and hydraulic fracturing) that provide access to new gas resources, (namely, shale gas) that were previously too expensive to produce.

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[12] *See* AEO 2010. The EIA projects that LNG imports will peak around 2020.

[13] Some analysts are even predicting that the U.S. will be a net exporter of natural gas by or before 2030. Recent interest has centered on converting import regasification terminals into liquefaction facilities that would export U.S. LNG to other countries around the world.

II. The Natural Gas Industry: Functions, Structure, and Transactions

A. Industry functions and structure

Figure 1 shows a schematic overview of the natural gas sector. The sector has four major segments: production, pipeline transportation, local distribution, and storage.

The revamped natural gas industry had its genesis in 1978 with the passage of the Natural Gas Policy Act, which mandated the partial, gradual abolition of price controls on wellhead gas. The market pressures from a liberalized wellhead market led to major FERC actions resulting in, most notably, nondiscriminatory open access by shippers[14] to the interstate pipeline system.[15] Since then, the industry has undergone monumental changes. Prior to that time, the industry operated under tight regulatory controls. This control extended from the wellhead function to local distribution with interstate pipelines as both the major seller and buyer of natural gas. Although not immune from transitional problems, the transformation of the natural gas industry over the past thirty years has encountered fewer difficulties and challenges than either the electricity or telecommunications industries.

The salient features of the U.S. natural gas sector follow. These features have evolved over time in response to technological, economic, and political forces.

1. Production

Natural gas production occurs via wells drilled into underground reservoirs of porous rock. After it is withdrawn from a well, the gas usually contains liquid hydrocarbons and nonhydrocarbon gases. The gas is then transported on gathering lines (low-pressure, small-diameter facilities) to processing facilities, which remove the liquid hydrocarbon content and other impurities to produce "dry" gas suitable for long-distance pipeline transportation.

Natural gas production was price regulated from the 1950s to the 1970s, after which time Congress gradually repealed price regulation on the premise that the market for production was competitive. The U.S. presently has over active 400,000 gas wells and close to 7,000 gas producers scattered across the country.

Domestic gas production increasingly comes from unconventional sources, namely tight gas sands, coal bed methane, and shale gas.[16] The Potential Gas Committee reported in mid-

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[14] Shippers are the contracting buyers of transportation service.

[15] For a description of the major federal actions, *see* EIA Major Federal Activities.

[16] EIA and other analysts project that unconventional gas production between now and 2035 will meet most of the domestic demand growth and offset the decline in conventional gas production and imports.

2009 that estimates of the total available U.S. future gas supply increased by 35 percent from 2006 to 2008, largely because of new drilling technologies unlocking substantial shale gas. The new estimates are the highest level ever reported by the Committee since it began tracking this information more than 40 years ago.[17]

The current consensus is that shale gas will help to assure sufficient U.S. gas supplies over the next several decades, assuming gas prices do not fall too low and environmental opposition to hydraulic fracturing does not intensify.[18] There is also the still unanswered question of how much it will cost to drill and produce shale gas beyond what we have developed so far. The experience up to now has been encouraging, but uncertainty remains. The most likely prospect is that we will extract large amounts of shale gas over the next several decades at a reasonable cost.[19]

2. Pipeline transportation

The second major function of the natural gas industry is pipeline transportation. Interstate pipelines carry most of the gas from gas fields to market areas. The Federal Energy Regulatory Commission (FERC) has jurisdiction over these pipelines because their services involve interstate commerce. Specifically, FERC regulates the rates, and terms and conditions, of interstate pipelines because of the predominant situation of inadequate competition. One major activity of FERC in the years ahead will be to approve large investments in interstate pipeline development.[20]

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[17] The Committee comprises both industry and academic experts. *See* a summary of the study here.

[18] *See*, for example, U.S. Department of Energy and National Energy Technology Laboratory, *Modern Gas Shale Development in the United States: A Primer*, April 2009. Hydraulic fracturing involves the injection of a mix of water, sand, and chemicals into the earth at a pressure great enough to crack the rock. The Energy Policy Act of 2005 exempted fluids used in hydraulic fracturing from protections under the Clean Air Act, Safe Drinking Water Act, and Clean Water Act. New York has suspended production of shale gas until the completion of a state study on the environmental effects of drilling and hydraulic fracturing. The fear is that hydraulic fracturing could contaminate drinking water.

[19] *See*, for example, U.S. Energy Information Administration, *Annual Energy Outlook 2010*, May 2010.

[20] Analysts expect pipelines to invest billions of dollars annually over the next several years to upgrade or expand their systems. *See*, for example, *U.S. Energy Information Administration, Expansion of U.S. Natural Gas Pipeline Network: Additions in 2008 and Projects through 2011*, September 2009.

The lower 48 states have about 300,000 miles of gas pipelines.[21] Unlike other energy sources, transporting gas by alternative modes of transportation, such as by truck or by water, is generally either not feasible or uneconomical.

Individual pipelines control their operations, unlike the centralized control of transmission facilities in some regional electricity markets. The physics of gas transportation avoids some of the problems with electricity transmission that require more formalized coordination of individual systems within a network. Because gas cannot flow instantaneously from supply regions and storage fields to market areas, however, transportation customers must make arrangements (i.e., nominations)[22] in advance to ensure the deliverability of gas at required times, pressures, and locations.[23]

Interstate pipelines fall under contract carriage requirements in which owners must offer available capacity to interested shippers.[24] Contract carriage, which initiated in the mid-1980s, was a precursor to the opening up of competition in wholesale gas markets.

Since the issuing of FERC Order 636 in 1992,[25] holders of firm pipeline capacity can resell their unused capacity to other parties in what is called a capacity release market. The holders post the available capacity, in most instances, on an electronic bulletin board (EBB) operated by interstate pipelines.[26] Major sellers of unused pipeline capacity are local gas utilities, who purchase sufficient capacity to meet peak demands. Capacity is consequently

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[21] Rapid expansion of the interstate pipeline network occurred after World War II, which allowed for the connection of natural gas fields to markets.

[22] "Nomination" refers to the request for space by a shipper on the pipeline system to transport gas.

[23] For a discussion of gas nomination procedures, see the NRRI paper "Efforts to Harmonize Gas Pipeline Operations with the Demands of the Electricity Sector" at NRRI 06-11. Nominations have the purpose of either scheduling or adjusting the amount of gas ultimately delivered. By scheduling gas, the pipeline commits to transporting the nominated quantity.

[24] Under FERC policies, a pipeline cannot discriminate against shippers who offer the same rate as other shippers for comparable service.

[25] The reader can access FERC Order 636 here. The FERC ruling also buttressed non-discriminatory access to interstate pipeline service by: (a) requiring pipelines to unbundle transportation from sales, (b) removing pipelines from the merchant function, and (c) requiring pipelines to provide open-access storage. Order 636 changed the pricing of pipeline services to a straight-fixed variable rate design. Under this rate design, a reservation charge recovers all of a pipeline's fixed costs, while a usage charge recovers the variable costs.

[26] EBBs act as a central exchange where buyers and sellers receive information to transact business. Marketers and other market participants have found that EBBs lower their transactions costs, especially for conducting business with pipelines and gas utilities.

available for sale during non-peak periods. These utilities charge their customers for the full cost of all contracted capacity, and then credit their customers with revenues earned from selling released capacity.[27]

In addition to long-distance pipeline transportation, intrastate pipelines transport gas within a state's boundaries. They connect gas producers to either local markets or the interstate pipeline system. About 30 percent of the total pipeline miles in the U.S. represent intrastate pipelines, with Texas having more intrastate pipeline miles than any other state. State public utility commissions have jurisdiction over intrastate pipelines. In some instances, an intrastate pipeline falls within the category of a "Hinshaw" pipeline. This pipeline, although receiving gas from interstate pipelines, is exempt under the Natural Gas Act from FERC jurisdiction because the gas it delivers is consumed only within the state in which it operates.

3. Local distribution

Local gas transportation, commonly referred to as distribution service, moves natural gas from the "city gate" (i.e., the point of interconnection between the interstate pipeline system and the local distribution system) to the end users of gas. These end users include homes, businesses, industrial facilities, and electric generating plants. Local distribution service is a natural monopoly service; that is, a single company serves a local area, with the company usually protected from competition by state law. In other words, most local gas distributors have exclusive rights to distribute gas in a designated geographic area. State public utility commissions regulate local distribution.

The distribution network includes low-pressure distribution lines and measurement and pressure regulators.[28] Local distribution involves transporting gas from delivery points along interstate and intrastate pipelines through small-diameter distribution pipes. Compared with interstate and intrastate pipelines, local distributors serve a much larger number of customers at a much lower throughput per customer.[29]

Local distribution utilities provide both bundled sales service and unbundled (also known as stand-alone) transportation service. In bundled service, the local utility buys and resells to retail customers both the gas commodity and interstate transportation.[30] Stand-alone service is

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[27] In June 2009, FERC Order 712 eased certain restrictions on short-term pipeline capacity-release transactions. For example, it eliminated price caps on capacity-release transactions of one year or less. *See* FERC Major Orders.

[28] A measurement regulator is a facility that measures and regulates the flow of gas in a distribution system. A pressure regulator is a device that maintains the gas pressure on a distribution system within a tolerable band.

[29] "Throughput" refers to the gas volumes delivered by a pipeline or local distribution company. Both entities make higher profits when their throughput increases.

[30] Local gas utilities often refer to this service as the "merchant function."

the provision of unbundled physical distribution service to customers, usually large customers. Several states have expanded competition in the retail market through legislation and regulatory rules that allow residential and commercial customers the ability to purchase their gas from alternative suppliers, who buy the gas commodity from marketers or others and then hire the local gas distributor to transport the gas to the site of consumption.

A major activity of local distribution companies is to acquire gas and deliver it to the city gate. Prior to FERC Order 636 (1992), retail gas utilities procured much of their city-gate supplies from the interstate pipelines under long-term contracts for the gas commodity, transportation, and off-system storage services. Order 636 caused gas utilities to procure more of their gas supplies separately from transportation service. Consequently, since 1992, gas utilities have played a greater role in managing their gas procurement practices.

Gas purchasing practices contain two distinct parts. The first part involves the utility's procuring gas and transportation at a reasonable price to meet expected peak-day, peak-month, and seasonal demands. The second part, which has received more attention since 2000 when wholesale gas prices began to rise to a new plateau, involves managing price volatility with financial derivatives, stored gas, and physical long-term purchase contracts.[31]

A major function of distribution companies is to price the services they provide to retail customers. State commissions regulate these prices, generally on the basis of cost of service where a utility has the opportunity to receive adequate revenues to cover its costs (including a return on investment and depreciation). Commissions have recently approved new ratemaking mechanisms for gas utilities. These mechanisms, which deviate from traditional practices, include cost and revenue trackers, formula rate plans, and multi-year price and revenue caps. Cost trackers, for example, are a general category of devices that allow, outside of a general rate case, recovery of costs in specified categories;[32] revenue trackers compensate a utility for revenue losses between rate cases because of energy-efficiency programs and other factors (e.g., the price elasticity of demand).[33] Formula rate plans allow a utility to adjust its base rates outside of a general rate case, usually annually, based on an actual or projected rate of return (ROR) on rate base or equity that falls outside some commission-defined band.[34]

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[31] *See*, for example, the NRRI paper "Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach" at NRRI 08-07.

[32] *See* the NRRI paper "How Should Regulators View Cost Trackers?" at NRRI 09-13.

[33] *See* the NRRI paper "Revenue Decoupling for Natural Gas Utilities," at NRRI 06-06.

[34] *See* the NRRI paper "Formula Rate Plans: Do They Promote the Public Interest" at NRRI 10-11.

4. Storage

Storage capability is an especially attractive feature of the U.S. natural gas industry. This country has added much new storage capacity since the beginning of this century.

Storage facilities serve both wholesale and retail markets (which number around 400 in the U.S.). They perform valuable functions by reducing the magnitude of short-term price volatility; assisting producers, marketers, pipelines, and gas utilities in better managing the price and availability of gas year-round; and creating arbitrage opportunities for market participants. The primary purpose of storage still remains, however, as a tool to reduce the chances that demand will go unserved during peak usage periods.

Storage facilities include salt caverns and depleted gas fields (i.e., underground storage), and above-ground LNG tanks.[35] We have seen several new storage facilities built in the last five years, partially as a hedge against volatile price swings.

Many pipelines own and operate storage facilities, which perform multiple functions. The pipelines can use their storage for load balancing[36] and system supply management; they also can lease storage capacity to other industry participants, such as marketers, local gas utilities, and large gas users. FERC regulates the sale of storage service in interstate commerce. Similar to interstate pipelines, wholesale storage facilities have open access requirements. One aspect of this regulation is a requirement that owners make capacity available to interested parties at the regulated or market rate.[37]

Distribution companies also operate storage facilities, as well as leasing storage capacity from pipelines and other owners. Distribution companies rely on storage to provide valuable peaking capability during the winter months, reduce the need for higher-cost annual firm pipeline transportation, and provide access to normally lower-cost summer gas supplies. Overall, storage allows the utilities to operate more efficiently and reliably. Many utilities, for example, use stored gas to meet a large portion (for some utilities, half or more) of customer demand on the

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[35] For background information on gas storage, *see* the EIA website here.

[36] "Balancing" refers to the situation in which the amount of gas scheduled for transportation equals the amount actually delivered. The shipper can receive gas (both nominated and un-nominated) on a daily, monthly, or seasonal basis up to its firm entitlements without incurring daily balancing and scheduling penalties. Balancing is especially valuable for maintaining a gas utility's system integrity against unpredictable demand.

[37] Section 312 of the Energy Policy Act of 2005 made it easier for storage operators to charge market-based prices by lifting the requirement on operators to demonstrate the absence of market power. FERC must determine, however, that market-based rates are in the public interest and needed to encourage the construction of the capacity, and that customers are adequately protected.

winter's coldest days. State commissions regulate the on-system storage activities carried out by the local distribution utilities.

B. Transactions

Prior to the 1980s, a conspicuous feature of the industry was contracts over long durations (e.g., over twenty years) at fixed prices, for both producer-pipeline transactions and pipeline-gas utility transactions. Starting around 1985, trading arrangements within the natural gas industry have become much more short-term and flexible, in both price and terms and conditions, compared to prior periods. We have observed this trend throughout the sector, from gas procurement, gas storage, and retail transactions to capacity contracting for pipeline services.

This trend is a result of a more open and restructured natural gas market, among other factors. This market includes buyers and sellers consummating trades with minimal transaction costs. Other factors favoring shorter-term contracts since the mid-1980s include a highly developed financial market for gas hedging, regulatory prudence reviews of natural gas purchasing practices, growing short- and long-term price volatility in natural gas physical and financial markets, and the evolution of short-term electricity markets. The last factor stems from generators' finding it excessively risky to commit on a long-term basis to gas purchases when they do not have long-term commitments from electricity buyers.

In sum, the primary force behind this broad reshaping of trading arrangements is simple economics: Retail gas and electricity consumers have had more choices of suppliers, and gas utilities have faced more uncertainty over future prices and their load requirements. As gas utilities, for example, downsized the bundled-sales-service side of their business, they invariably had less desire for long-term commitments. Overall, competitive pressures have made long-term commitments a more expensive proposition for utilities by increasing risk.

1. The spot market

Spot transactions involve the purchase of a commodity for immediate or near-term use. For natural gas, these transactions involve sales within the following 30 days. A utility will use the spot market to buy natural gas for the next day or month. Well-developed day-ahead and monthly spot markets for natural gas have thrived since the early 1990s. The U.S. has several spot markets with a large number of sellers and buyers transacting natural gas and other services. A spot market usually has several pipeline interconnections. Spot transactions based on standardized North American Energy Standards Board (NAESB) contracts assure individual buyers of reliable supply under universal contract provisions.[38]

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[38] The NAESB website (http://www.naesb.org/) remarks that:

> The North American Energy Standards Board (NAESB) serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as

Prices in these markets reflect short-term supply-and-demand movements as well as futures prices. Because gas is a commodity, spot prices can change quickly and fluctuate widely, with the timing of gas purchases having a large effect on a utility's actual annual average gas costs. The spot price of gas depends on several factors, including production cost, storage levels, economic conditions, weather, pipeline capacity, and random shocks (e.g., events in the Middle East affecting oil prices).

Spot transactions provide flexibility to the utility in the daily balancing of supply with demand. Gas utilities use spot purchases to supplement firm contracts during times of high demand or to displace gas having a higher cost. Spot markets also require repeated trading, which over time can drive up transaction costs.

2. Long-term contracting

Long-term contracting represents a transaction in which the seller and utility desire more certainty, over the next few or several years, in price and reliability than spot-market transactions can offer. The parties also might want to customize other non-price terms to their unique needs. The parties' risk aversion, as well as market conditions, plays a large role in a contract's negotiated terms. These conditions include the predictability of the future, and the relative bargaining strength and the planning capability of each party. Evidence of risk aversion is the higher price that a buyer would be willing to pay to have more stability of price over time.

Both utilities and gas suppliers recently have given increased attention to the possibility of long-term contracting.[39] This new attention relies on the predictions that the U.S. gas market will have ample supplies of natural gas over the next several decades, resulting in prices becoming more stable—and predictable—than those of the past ten years. With a supply-abundant gas future and accompanying price stability and predictability, both buyers and sellers might be willing in the future to make long-term commitments.[40] The trading parties might find it easier, for example, to specify contractual terms because there would likely be fewer contingencies (e.g., gas prices would be less likely to soar to extremely high levels). Thus, renegotiations would occur less often, thereby reducing the lower transaction costs associated

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recognized by its customers, business community, participants, and regulatory entities.

[39] *See*, for example, B. Casselman and R. Smith, "Natural-Gas Producers Seek Long-Term Contracts," *Wall Street Journal*, December, at WSJ Article. Earlier this decade, studies by the National Petroleum (NPC), the Interstate Natural Gas Association of America (INGAA), and the Keystone Center supported long-term contracting in various segments of the natural gas industry.

[40] One source of abundant gas is shale gas, which can respond more quickly to changes in price than conventional sources of gas. One implication of a quicker response is that price volatility should be less pronounced, with prices more stable over time.

with long-term contracting.[41] Buyers might also be reluctant to commit to an investment (e.g., an electric generating plant) that requires the purchase of natural gas on a long-term basis unless offered a fixed-price contract. It is unknown at this time to what extent this reversal of recent trends will spread throughout the natural gas industry.

3. Hedging activities

Hedging refers to an economic activity in which a person or entity enters the market with the specific intent of protecting an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. Hedges come in both physical and financial forms: Utilities can use storage or bilateral physical contracts with fixed prices as hedges; they can also purchase financial hedges, such as futures contracts, options, and swaps. High price volatility supports consideration of hedging by utilities and other large consumers, including hedging with financial derivatives. Customers can suffer non-trivial losses when natural gas prices rise to unusually high levels. This effect implies that a utility should hedge to prevent customers from paying extremely high prices, especially during high-demand periods. Relative to physical hedges, such as storage and bilateral physical contracts, financial derivatives can have lower transaction costs and higher liquidity. In almost all instances, financial hedges do not result in the delivery of actual gas volumes.

A robust futures and over-the-counter financial derivatives market for gas has existed since the early 1990s. Several gas utilities use futures contracts, options, and other financial derivatives to hedge their physical gas purchases.[42] Since 2000, both gas distributors and state public utility commissions have recognized the importance of financial derivatives in managing price risk. These derivatives reflect the natural outgrowth of the well-developed gas spot markets to stimulate hedging activities. Most industry experts consider natural gas a commodity

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[41] Transaction costs play an important role in the selected institutional arrangement for gas purchases by a utility. Transaction costs are those costs incurred by trading parties to find each other and then to negotiate, draft, monitor, and enforce contracts. As expressed by one noted economist:

> [T]here were costs of using the pricing mechanism. What the prices are has to be discovered. There are negotiations to be undertaken, contracts to be drawn up, inspections to be made, arrangements to be made to settle disputes, and so on. These costs have come to be known as *transaction costs*. Their existence implies that methods of coordination alternative to the market, which themselves are costly and in various ways imperfect, may nonetheless be preferable to relying on the pricing mechanism… (R.H. Coase, *Essays on Economics and Economists* (Chicago, IL: The University of Chicago Press, 1994), 7-8 (emphasis added)).

[42] For an overview of gas hedging, see the NRRI report "Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues" at NRRI 01-08; and the paper by Mike Gettings at Hedging Paper.

whose price exhibits high volatility and close correlation with fluctuations in consumption and production.

4. Market hubs

Several pipelines interconnect at market centers, usually referred to as “hubs.” Hubs serve to lower transaction costs by facilitating commercial transactions between buyers and sellers at pipeline interconnections, storage areas, and major market areas. Hubs, which number about twenty-eight scattered across the country, provide different services, including pipeline interconnection service and electronic information to assist with gas trading. Henry Hub is the most active gas hub in North America, with access to major onshore and offshore gas producers. It is a pipeline interchange located in eastern Louisiana that serves as the delivery point of natural gas futures contracts.[43]

5. The role of marketers

Independent and affiliated marketers play an important intermediary role in providing gas services to the different market players. Marketers are entities that purchase and resell gas in either the wholesale or retail market. Some marketers participate only locally or regionally, while others have a national presence. Marketers frequently package gas commodity and pipeline transportation to deliver gas to the city gate. Marketers may own pipeline-capacity rights or purchase rights in the secondary (i.e., capacity release) market.

6. Retail competition

Distribution utilities provide open access (i.e., local transportation-only service) to some of their customers. These customers then shop for gas supply among retail marketers. In other words, physical distribution remains a monopoly service, but the retail sale of gas operates in a more competitive market, with the local distributor almost always the default supplier.[44] The rationale for open access at the retail level is the potential for small customers to benefit from expanding competition in the retail gas market. New opportunities for customers, at least in theory, would predict improved economic efficiency, lower prices, the offering of new value-added services, and even enhanced quality of consumer service.

For over 20 years almost all large customers in the U.S. have bought only transportation service from the local gas utility. Since 1995 several states have enacted legislation or rules that

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[43] That is, Henry Hub is the designated delivery point for all New York Mercantile Exchange (NYMEX) natural gas futures contracts. For information on NYMEX, go here.

[44] For gas choice programs, state regulators have had to address such issues as: (1) what services should be unbundled, (2) rules governing affiliate transactions, (3) service obligations of the local gas utility, and (4) market certification and conditions for entry. *See*, for example, the NRRI report “Unbundling the Retail Gas Market: Current Activities and Guidance for Serving Residential and Small Customers” at NRRI 96-13.

allow residential customers to purchase their gas supplies from someone other than the local gas utility. Specifically, twenty-one states and the District of Columbia currently allow residential and commercial customers to choose their gas-commodity supplier. (Industry observers commonly refer to these initiatives as “customer choice” programs.) This number has remained the same since 2003. These jurisdictions comprise about 55 percent of the total residential gas customers in the U.S. As of December 2008, 5.1 million residential customers, or about 15 percent of eligible residential customers, chose a non-utility provider (e.g., energy marketer).[45] More than 60 percent of these customers reside in Georgia or Ohio.

Many large customers, including power generators and industrial facilities, bypass the local gas utility by taking gas off the interstate or intrastate pipeline system. These customers require no services from the local utility. Gas utilities lose profits when customers bypass, while the remaining customers of the utility typically pay higher rates to compensate the utility for these lost profits. This outcome results from the utility’s lost revenues to cover fixed distribution costs.

[45] For an overview of the status of small-customer choice programs, see EIA Customer Choice.

III. Jurisdiction over the Natural Gas Industry[46]

As a result of industry restructuring that began over twenty-five years ago, direct regulation of the natural gas industry today applies mostly to pipeline transportation, storage, and local distribution. For these functions, regulation by FERC or state public utility commissions consists of price setting, rules for access to the delivery facilities, and approval for the siting and construction of new delivery facilities. The rationale for tight regulation of these functions is their natural monopoly feature.[47]

Other market functions, such as gas production and the marketing of gas services, are free of direct (e.g., price) regulation. These functions do have some regulatory oversight, however. Marketers affiliated with regulated utilities, for example, might be subject to standards-of-conduct rules. Pipeline operations and infrastructure are subject to oversight by the U.S. Department of Transportation, including regular inspections of actual pipelines and safety plans. As discussed in Part III.B, in many states these functions are actually carried out by the state commission. Pipelines are also subject to oversight by the EPA under the Clean Water and Clean Air Acts.

A. FERC[48]

The current mission of FERC is to "ensure the adequate supply of natural gas at reasonable prices." FERC's major duties include: (1) regulating pipeline, storage, and liquefied natural gas facility construction; (2) regulating natural gas transportation, including setting rates, in interstate commerce; (3) issuing certificates of public convenience and necessity for interstate pipelines and storage facilities;[49] and (4) setting rates for interstate and wholesale storage services.

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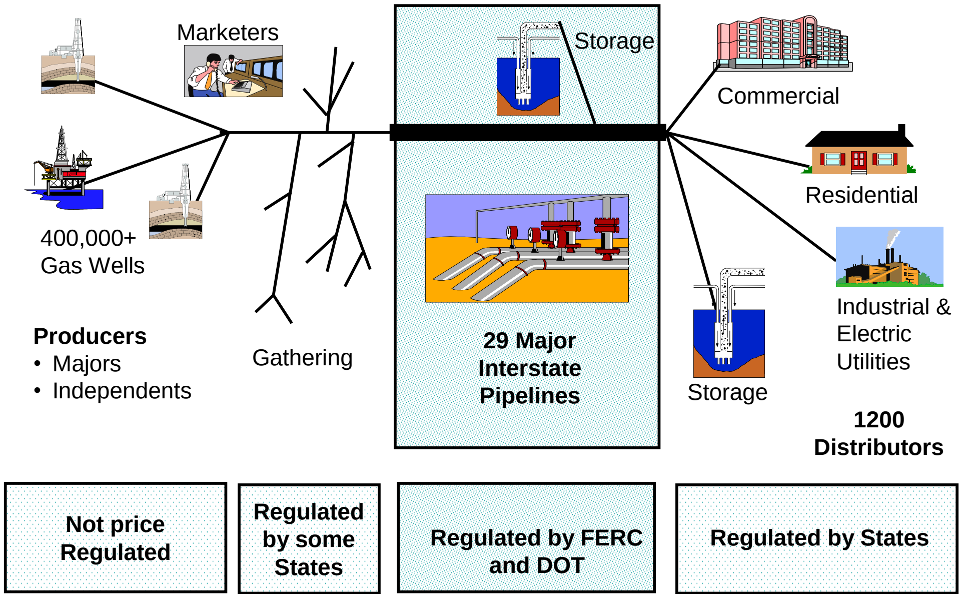
[46] "Jurisdiction" means the legal authority to regulate. In some instances, an agency has exercised this jurisdiction by reducing or eliminating regulation. The discussion below addresses only the jurisdiction to regulate, not the regulatory (or deregulatory) actions.

[47] There are different definitions of natural monopoly. One relates to the premise that total production costs would rise if two or more firms produced instead of one; the single firm in such a market is called a "natural monopoly." A second definition associates natural monopoly not with the number of sellers in a market but with the relationship between demand and the technology of supply. To put it in lay terms, a natural monopoly occurs when the pie isn't large enough for more than one company to turn a profit without customers' rates going up.

[48] See FERC General Information for an overview of FERC regulation of pipelines and storage facilities.

[49] A certificate issued by FERC permits a pipeline or other wholesale entity to engage in the transportation or sale for resale (e.g., wholesale sale), or both, of natural gas in interstate

Figure 1: Structure of the U.S. Natural Gas Sector



The Natural Gas Act (NGA) requires FERC to set “just and reasonable” rates. FERC generally applies the principles of cost-of-service ratemaking in setting pipeline rates. FERC uses a straight-fixed variable rate design where a reservation charge recovers a pipeline’s fixed costs, with the variable costs recovered through a usage charge.[50]

FERC has enumerated five major principles underlying its actions and policies:

1. Commodity and other competitive goods and services are best left unregulated.

2. Interstate gas pipelines have monopoly features that warrant their regulation.

3. Pipeline services must operate without undue discrimination and preference.

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commerce, or to acquire and operate the facilities needed to consummate these transactions. In applying for a certificate to expand a pipeline, for example, the owner would have to demonstrate to FERC that the expansion will promote the public interest, is economically feasible, and will not have a major environmental impact. The certificate also allows the pipeline, storage facility, or LNG facility to exercise eminent domain, if necessary.

[50] *See* FERC Rate Manual.

4. The development of new supply sources and infrastructure is important to ensure adequate gas supplies at reasonable prices.

5. Regulation is a balancing act that tries to harmonize the different interests of stakeholders.

B. Safety regulation

Gas utilities spend around $7 billion annually on safety-related activities. About half of this money is spent on complying with federal and state regulations.

The U.S. Department of Transportation (DOT), within its Pipeline and Hazardous Materials Safety Administration (PHMSA), is responsible for enforcing regulations pertaining to pipeline safety.[51] Federal pipeline safety regulations have the objectives of: (1) assuring safety in the design, construction, inspection, testing, operation, and maintenance of pipeline facilities and in the siting, construction, operation, and maintenance of LNG facilities; and (2) setting out parameters for administering the pipeline safety program. Federal safety regulations apply to all interstate and distribution pipelines in the country.

State public utility commissions partner with DOT to comply with pipeline safety regulations. The states are responsible for virtually all gas distribution pipelines, gas gathering pipelines, and intrastate pipelines, assuming that their safety programs receive federal certification or they enter into an agreement with DOT. Federal pipeline statutes provide for exclusive federal authority to regulate the safety of interstate pipelines. DOT, however, may authorize a state to act as its agent.

The federal/state partnership helps to assure nationwide uniformity of the implementation of the pipeline safety program. The states must enforce at least the federal regulations; many states have regulations more stringent than federal regulations.

The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act of 2006) expanded the Federal pipeline safety program.[52] It includes major mandates that the industry is currently working with PHMSA to implement. The Act contains four core provisions that have the intent of improving distribution pipeline safety: (1) excavation damage prevention, (2) distribution integrity management programs, (3) excess flow valves, and (4) control room management. It also authorizes PHMSA to reimburse states for up to 80 percent of their costs as partners in enforcing federal regulations.

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[51] *See* DOT Safety for an overview of DOT activities on pipeline safety.

[52] *See* PIPES Act of 2006.

C. State regulation

State commissions play an important role in regulating the natural gas sector. Although the marketplace determines the price of commodity gas and FERC sets rates for interstate pipelines and wholesale storage service, state commissions approve the cost of purchased gas by gas utilities in addition to the distribution-related costs incurred by gas utilities.[53] State commissions also regulate intrastate pipelines and some gathering facilities.

For all states (except for Hawaii), the utility recovers its purchased gas costs through some automatic adjustment mechanism. In most states, the utility passes through, outside of a general rate case, dollar-for-dollar purchased gas costs, which include the cost of the gas commodity, pipeline transportation, and wholesale storage services, subject to a prudence review. State commissions have adopted these mechanisms for three principal reasons: (1) purchased gas costs are substantial and recurring, (2) they are mostly beyond the control of utility management, and (3) they are not reliably predictable.

The non-gas portion of rates (often referred to as the "base rate") recovers those costs related to investment in, and operation of, the distribution system. This base rate usually consists of a two-part tariff, a monthly customer charge, and a volumetric charge. The customer charge recovers the direct cost of serving a customer, including the cost for meters, meter reading, billing and collection, servicing an account, call centers, and other costs independent of gas usage. The volumetric charge recovers the remaining non-gas costs of a utility. It includes both operating costs and capital costs not recovered in the customer charge. A state commission sets the base rate in a formal rate proceeding. For those customers taking only transportation service from the local utility, a state commission regulates the price of that service as well.

State commissions also approve the construction of distribution facilities and intrastate pipelines, which include main distribution lines and service lines, metering systems, and storage facilities located within a utility's service area. State commissions issue certificates of convenience and necessity in sanctioning new or replacement facilities. Commissions review the economics of and need for these facilities before issuing a certificate.

As part of their legal obligations, state commissions require that gas utilities provide reliable and safe service. They might require, for example, that a utility replace some of its existing pipes to comply with safety standards or construct new service lines to accommodate new customers. Several gas utilities are currently spending large amounts of money to replace their bare steel and cast iron distribution pipes. The new pipes are either state-of-the-art plastic or steel pipes. The replacements will improve the safety and reliability of distribution systems, as old pipes are susceptible to leaks and corrosion.

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[53] The gas commodity component represents about half of a typical residential customer's gas bill, with the remaining portion composed of pipeline and distribution costs. The vast majority of gas utilities profit only from local gas delivery; they do not profit from the buying and selling of the gas commodity. See EIA's Natural Gas Prices Explained.

State commissions also involve themselves with social issues such as the affordability of gas service to low-income households and energy conservation by customers. Some commissions have taken an active role by requiring gas utilities to finance and administer energy conservation initiatives and offer eligible low-income households discounted rates and other monetary assistance for gas service.

IV. Major State Regulatory Issues

Some of the major natural gas issues facing state regulators relate to: (a) retail ratemaking, (b) risk management and hedging, (c) gas-fired electricity generation, (d) wholesale gas markets, (e) integrated resource planning and energy efficiency, (f) customer choice programs, (g) natural gas vehicles, (h) new technologies, and (i) energy affordability.

New social objectives imposed on gas utilities, as well as changed market conditions, have triggered the need for state regulators to consider *new ratemaking approaches*. One of these objectives is the promotion of energy efficiency.

Risk management in the form of *hedging* is an integral element in natural gas markets. In recent years, regulators and others have questioned the merits of hedging given the higher prices utility customers have sometimes had to pay because of it.

One concern of state regulators is that greenhouse gas regulations could tighten wholesale gas markets because of *increased gas-fired electricity generation* producing higher gas prices to residential, commercial, and industrial customers. It is unclear whether regulators should do anything about this possibility, especially if natural gas offers the lowest-cost option for meeting new regulations designed to reduce greenhouse gases.

Regulators need to keep abreast of forecasts for, and developments in, the *wholesale gas market*. The natural gas market, at least for the next year or two, will be a buyer's market, and it is likely that prices will continue to stay low with weak pressure for upward movement. There is much uncertainty on both the supply and demand sides of the natural gas market for the long term.

State regulators have shown greater interest in requiring *integrated resource planning* for gas utilities. A major reason is the increased focus they have placed on promoting energy efficiency.

Some states are now questioning whether *customer choice programs* for residential customers have produced the expected benefits. Uninformed and misinformed customers might have made wrong decisions by choosing a third-party marketer retailer rather than staying with their local utility for fully bundled service.

With an optimistic future presenting in gas supplies and price, *natural gas vehicles* have recently received more attention as a potential substitute for petroleum-based vehicles. One challenge facing the natural gas industry is to find new and additional uses for gas in the different demand sectors.[54]

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[54] Some analysts predict that the increased use of natural gas for transportation will derive more from its use in electricity generation to help recharge electric vehicles, rather than from its fueling of NGVs.

The possibility of *new technologies* adopted by gas utilities in the years ahead requires careful regulatory review of cost recovery, risk allocation, and benefit-cost calculations from the perspective of retail consumers. Regulatory actions can affect the speed of market penetration of new technologies.

With the deep recession lingering, *energy affordability* has become a more serious problem for low-income households.[55] They have found it increasingly difficult to pay their natural gas bills. Low-income households spend a much higher share of their incomes on home energy use than do other households. Low-income households also have difficulty finding the money to pay for energy-efficiency investments.

A. Retail ratemaking

The recent ratemaking proposals by gas utilities reflect changes in market conditions for natural gas as well as new regulatory and energy policies. These new proposals include revenue decoupling, cost riders, straight-fixed variable rate design, and weather normalization adjustments.

State commissions face the challenge of deciding on the acceptability of these new practices in line with the various objectives they assign to ratemaking.[56] One example is the efforts of regulators to harmonize the different regulatory objectives with the advancement of energy efficiency. Energy efficiency can conflict with the goals of keeping short-term rates as low as possible and allowing a utility a reasonable opportunity to earn its allowed rate of return. Ratemaking plays a crucial role in achieving this harmonization. Ratemaking decisions require regulators to consider mechanisms that have differing effects on regulatory objectives, with most advancing some regulatory objectives while impeding others. Making tradeoffs among ratemaking objectives that best serve the public interest poses a difficult but inevitable task for regulators.[57] Some ratemaking mechanisms for promoting energy efficiency, for example, are

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[55] An October 2010 AGA report stated that:

> The impacts of the recession continue to impair the ability of many families to pay their utility bills. While the number of families assisted by LIHEAP has grown by 3.1 million, approximately 80 percent of those that qualify do not get this aid. The poverty rate in 2009 achieved the highest level since 1994. Almost four million more people lived in poverty in 2009 than in 2008. Median full-time earnings have fallen. The unemployment rate hovers at just under 10 percent. Finally, the Department of Energy forecasts higher prices this winter for natural gas, electricity, and heating oil. Thus, the need for energy bill payment assistance by low-income families continues. (*See* here.)

[56] *See* NRRI studies in footnotes 32-34.

[57] *See* the NRRI paper "Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas" at NRRI 07-01.

better at achieving certain objectives but worse at achieving others. One emerging issue centers on designing rates that address the conflicting objectives of promoting energy efficiency while at the same time marketing natural gas in an environment of abundant supply.

Regulators should have the following knowledge and experience in addressing new ratemaking proposals:

1. Decision analysis to address multi-objective actions

2. Understanding of consumer behavior under different rate designs

3. Determination of the "just and reasonableness" of different ratemaking methods

4. Economic analysis of the efficiency and equity effects

5. Cost-benefit analysis of different ratemaking methods

6. Flexibility in review of rate designs and the methods for such review, along with acceptance of the clear inability of any particular method or group of methods to provide precise and unproblematic answers to questions about the balancing of interests.

B. Risk management and hedging

In avoiding a dramatic run-up in gas prices charges to their customers, most gas utilities hedge a portion of the gas they purchase. Utilities have continuously modified their hedging activities over time to better accommodate changed market conditions and in response to past experiences. Some regulators have begun investigating the merits of existing hedging programs. They are asking: How have hedging programs worked relative to expectations? Have programs been oversold? Should commissions revisit their policies on hedging? Triggering these inquiries is evidence that some hedging programs, over the past few years, have added millions of dollars to customers' bills.

In evaluating past hedging strategies, regulators need knowledge and a reasonable amount of experience in the following areas:

1. Financial derivatives (e.g., futures, options, swaps, collars)

2. Risk analysis involving natural gas prices

3. Financial markets

4. Gas procurement practices

5. Contracting

C. Gas-fired electricity generation

With high-carbon coal plants facing serious obstacles, new nuclear capacity unavailable until at least the middle of the next decade, and the expansion of renewable energy falling short of additional generating requirements, gas-fired plants have emerged as the "filler fuel" for the near term. Some analysts also see natural gas as a long-term fuel for electricity generation.[58] Unlike most of the other fuels used in power generation, natural gas is consumed for a wide variety of reasons and across a large portion of the population. When the demand for natural gas increases for one sector, it tends to drive up the price paid by all natural gas users.

In addressing this issue, regulators need knowledge and a reasonable level of experience in the following areas:

1. Interpretation of different forecasts

2. Developments in the electricity industry

3. Different electricity generation technologies

4. Proposed greenhouse gas legislation and regulations and their effects on the gas market.

D. Wholesale gas markets

A major part of retail customers' gas bills is the wholesale cost of gas. Although state regulators do not have authority over wholesale markets, they need to understand these markets and assess their future prices and supply. They should, for example, synthesize and analyze recent gas supply, price, and other market developments. If the consensus is that gas prices will rise dramatically over the next five years, regulators might want to presently initiate policies and take other actions in anticipation of this development.

In understanding wholesale gas markets, regulators need knowledge and a reasonable level of experience in the following areas:

1. Identification of credible forecasts

2. Evaluation of these forecasts[59]

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[58] EIA has projected in its reference case that natural-gas plants will account for 46 percent of new generating capacity additions between 2009 and 2035. *See* U.S. Energy Information Administration, *Annual Energy Outlook 2010*, May 2010, 67.

[59] *See*, for example, the NRRI paper "Looking before Leaping: Are Your Utility's Gas Price Forecasts Accurate?" at NRRI 10-08.

3. Major short-term and long-term market developments

4. Unconventional natural gas (e.g., shale gas, coal bed methane, tight sands gas) and LNG

5. The major factors affecting wholesale gas prices and availability

E. Integrated resource planning and energy efficiency

Integrated resource planning (IRP) compares demand-side options such as energy-efficiency programs on an equal basis with supply-side alternatives. Questions relate to the role that a utility should play in advancing energy efficiency, the definition of energy efficiency, the design of cost-effective initiatives, the financing of those initiatives, and the required utility incentives for promoting energy efficiency. Some gas utilities have suggested that regulators should promote electric-to-gas substitution (EGS)[60] in an IRP process or in some other venue. They have argued that EGS has benefits comparable to energy efficiency and that regulators should therefore evaluate electric-to-gas substitution similarly.[61]

The U.S. will expend substantial resources in the following decades to promote energy efficiency.[62] The Obama administration has emphasized the importance of advancing energy efficiency by allocating billions of dollars to the states to further this goal. State public utility commissions and other state entities are also aggressively pushing energy utilities to promote

[60] "Electric-to-gas substitution" refers to the decision of small, generally residential consumers to use natural gas rather than electricity for certain end-use applications. The decision can involve conversion from electricity to natural gas in an existing home or installation of gas-burning equipment in a new home. In each instance, the consumer must decide on the appliance or energy-using equipment she wants to purchase. End uses in which electric-to-gas substitution is common include space heating, water heating, cooking, and clothes drying.

[61] *See* the NRRI paper "Electric-to-Gas Substitution: What Should Regulators Do?" at NRRI 09-07.

[62] Efforts to advance energy efficiency stem from the presumption of market problems and consumer irrationality. Examples include inadequate consumer information or information that is confusing and difficult for utility customers to interpret; significant uncertainty about benefits; high transactions costs; and split incentives between builders and occupants. Market problems can also derive from regulatory actions such as setting faulty rate structures. One example of faulty pricing is subsidized rates that are offered to one class of customers and paid for by other customers. Behavioral problems can arise from consumers undervaluing the multi-year benefits of energy efficiency relative to the initial costs, as well as from inertia (e.g., laziness), in which consumers decide to do nothing even though they expect to receive net benefits from devoting resources to energy efficiency.

energy efficiency.[63] With large energy-efficiency expenditures, it is imperative to maximize the benefits. It is not enough just to implement energy-efficiency initiatives that pass some cost-benefit test; they should also produce the highest possible benefits for the dollars expended.[64] A good IRP process should strive to achieve this goal.

Regulators will need knowledge and a reasonable amount of experience in a wide range of areas in providing guidelines to utility plans, reviewing proposed plans, and judging whether they are in the public interest. These areas include:

1. Forecasting techniques
2. Optimization tools such as linear programming and portfolio theory
3. Wholesale gas markets, including supply and demand conditions
4. Gas utility operations
5. Decision analysis under uncertainty and multi-objectives
6. Measurement and verification of energy efficiency initiatives
7. Contracting and hedging
8. Utility behavior under different incentives and regulatory policies and rules

F. Customer choice programs

In quantifying the effects of retail competition on consumers, which in some instances might be negative, regulators will need to collect and interpret the data with sophisticated statistical techniques. The analysis requires an understanding of markets and what features separate markets that perform to the benefit of consumers from markets that don't. Regulators can use the evidence to continue with "customer choice," terminate it, or modify it to increase benefits.

Areas of needed knowledge and experience for evaluating "customer choice" include:

1. Market assessment
2. Different market structures and their effects on consumers and a firm's performance

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[63] Gas utilities spent nearly $565 million in energy efficiency programs in 2008 and close to $1 billion in 2009.

[64] *See* the NRRI paper "How Regulators Can Help to Increase the Benefits from Utility Energy-Efficiency Initiatives" at NRRI 09-09. This paper identifies ways to achieve maximum benefits from utility energy-efficiency initiatives.

3. Features of well-functioning markets

4. Conditions needed for workably competitive markets

5. Market power and its measurement

6. Market definitions

7. Market problems

G. Natural gas vehicles

Discoveries of shale gas, recognition of natural gas's smaller carbon footprint relative to gasoline, and advances in transportation-oriented gas technology have all induced renewed interest in natural gas vehicles (NGVs). Compared to vehicles using other forms of energy, NGVs have some favorable and unfavorable features.

Regulators should have the skills to evaluate studies and other analyses of the economics of natural gas vehicles (NGVs). They should also have skills in determining whether NGVs are in the public interest. If they are in the public interest, regulators should then have the capabilities to decide: (a) whether existing rules and regulations act as barriers to the development of NGVs, (b) the most effective actions to take in removing uneconomical barriers, (c) whether, to what extent, and how utilities should proceed in the development of NGVs, and (d) the effect of any utility actions to develop NGVs on customers and other regulatory objectives (e.g., cost-of-service rates, fair competition).

H. Penetration of new technologies

Gas utilities are likely to introduce new supply- and demand-side technologies in the years ahead. New technologies frequently have potentially high, but uncertain, benefits to consumers and society. In determining cost recovery and the speed of optimal market penetration, regulators will have to evaluate the merits of these technologies in terms of their effects on consumers. Regulators will require skills in: (a) measuring the risks to consumers and utility shareholders, (b) determining how different cost-recovery mechanisms would affect the utility's financial condition and the risks to consumers, (c) conceptualizing and measuring the benefits and costs of new technologies, and (d) determining the effects of consumer education on the market penetration of new demand-side technologies (e.g., innovative gas heat pumps, condensing water heaters).

I. Energy affordability to low-income households

Regulators should review different energy assistance initiatives if they desire to make energy affordable to low-income households.[65] A review should determine whether a particular

[65] Households who currently find energy unaffordable can include members of the middle class who lose their jobs or suffer serious losses in their financial wealth.

initiative achieves the regulatory goal of utility-service affordability (1) most effectively and (2) with minimal adverse effects on other goals.[66] An important dimension of effectiveness is to maximize the benefits to targeted households given the dollars funded by other utility customers. "Minimal adverse effects" means that in funding and executing energy assistance, regulators should mitigate distortions in pricing, energy consumption, and recipient behavior driven by moral-hazard incentives.[67] Regulators should have the skills needed to examine, and quantify to the extent possible, the differing effects of various energy-assistance options.[68] These effects include the benefits to participants, and changes in (a) the utility's net revenues, (b) the rates to funding customers, (c) energy consumption by participants, and (d) economic efficiency.

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[66] See the NRRI paper "How to Determine the Effectiveness of Energy Assistance, and Why It's Important" at NRRI 09-17.

[67] One example of a moral hazard is changes in customer actions based on being insulated from some or most risks relating to a particular area, e.g., paying for utility services.

[68] These options include: (1) lifeline rates, (2) rate discounts, (3) lump-sum bill assistance, (4) percentage-of-income plans, (5) customer-charge waivers, and (6) weatherization programs. *See* NRRI 09-17.