Briefing Note

Natural Gas in a Carbon-Constrained World

Ken Costello
Chief, Natural Gas Section
National Regulatory Research Institute
March 2008[1]

I. Description of the issue

Federal greenhouse gas (GHG) legislation will make carbon-based fuels less attractive because of requirements to buy emissions allowances or pay carbon taxes. The legislation's effects on various sources of energy for power generation will differ. The demand for coal, for example, should decrease as power generators switch from this energy source to more environmentally benign ones. Power generators will find renewable energy and other clean technologies more attractive, as they eliminate the need to make payments for allowances or carbon taxes. Natural gas, as a source of energy, emits less carbon dioxide (CO_2) than other fossil fuels, but more CO_2 than nuclear power and renewable energy. Many energy analysts view natural gas as a bridge fuel that power generators will continue to rely on in the near term until new nuclear power plants, clean coal technologies, and the rapid expansion of renewable energy become a commercial reality. Most industry analysts agree that, even with aggressive energy efficiency and renewable energy initiatives, the U.S. will still need to build large power plants that can meet future demands for electricity with zero- or low-carbon emissions.

One concern state commissions have is that GHG legislation could further tighten wholesale gas markets, resulting in higher gas prices to residential, commercial, and industrial customers. 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.

The gravity of the GHG-natural gas nexus has intensified with the recent suspension or cancellation of new coal-fired plant-building projects. New coal plants have become less attractive due to more intense public opposition, high costs, and looming GHG legislation. Because of the need to increase generating capacity over the next several years, electric utilities and non-utility generators will soon have to decide what kinds of facilities to build;[2] some are taking actions already. With high-carbon coal plants facing serious obstacles, new nuclear

[1] The author would like to thank David Magnus Boonin, Chief of the Electricity Section and Scott Hempling, Executive Director, both of the National Regulatory Research Institute, for their helpful comments.

[2] See North American Electric Reliability Corporation (NERC), *2007 Long-Term Reliability Assessment: 2007-2016*, October 2007.

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 seem to be the "filler fuel" for the near term. This situation, notwithstanding the aggressiveness of energy efficiency initiatives and the emergence of low-carbon technologies, parallels events starting in the early 1990s, when natural gas became the fuel of choice for a high percentage of new generating capacity. From 1999 to 2003, for example, 200,000 MW of new gas-fired generating capacity came on the market.[3] Back in the 1990s, wholesale gas prices averaged around $2 per Mcf, whereas future gas prices likely will fall in the $7-8 range.

The purpose of this briefing note is to highlight the predictions of experts on what effect GHG legislation will have on natural gas prices and demand. The briefing note also discusses the argument that in a carbon-constrained world fuel switching from electricity to natural gas could produce large benefits, from both an economic and environmental perspective.

The discussion below draws primarily on presentations made at the 2008 NARUC Winter Committee Meetings. These presentations were striking in both their number and their predictions about the effect of GHG legislation on natural gas markets. Although one might dispute the magnitude of the impact of GHG legislation on natural gas prices, the analyses offered at that meeting raise a legitimate concern that state commissions may want to address.

II. GHG legislation's effects on gas-fired electric generation: supply and price predictions

Below is a summary of different analyses on the future of gas-fired generation in a carbon-constrained environment. Many of these analyses assume the passage of the McCain-Lieberman bill (S. 280) or the Lieberman-Warner bill (S. 2191).[4] What stands out in the analyses is that, at least in the near term, the U.S. may have no choice but to rely on new gas-fired generating facilities to meet the future demand for electricity. Given the tightness of the gas markets, the outcome may be a sharp increase of gas prices, which will affect not only the price of electricity but also the price of natural gas to direct users such as households and businesses.

---

[3] Natural gas was the fuel of choice in the 1990s because of its desirable economic and environmental features.

[4] This McCain-Lieberman bill preceded the current bill most under discussion, the Lieberman-Warner bill, which was introduced in October 2007. Both bills include an economy-wide cap, allowance allocation and offsets. (See, for example, http://www.rff.org/climate.cfm.) The general effects of the two bills on the natural gas sector should be similar and not detract from the comments in this brief. For a discussion of how new GHG legislation can affect state commissions' decisions over the approval of new generation technologies, see Andrew G. Keeler, *State Commission Electricity Regulation Under a Federal Greenhouse Gas Cap-and-Trade Policy*, NRRI 08-01, January 2008 (found at http://nrri.org/pubs/electricity/08-01.pdf).

1. A study by the Natural Gas Council (NGC), published in October of last year, estimated that S. 280 will increase sharply the demand for and the price of natural gas.[5] The study calculated that by 2030, gas prices could be $4 per Mcf higher (in 2005 dollars) than present levels. (At the time of this writing, the Henry Hub price is around $8.50 per Mcf.) The NGC study depicts a high-cost scenario, especially when compared to an Energy Information Administration (EIA) study done in July of last year projecting a more modest outcome of S. 280 on gas markets (to be discussed later in this document).[6] Critics, mostly from the natural gas industry, argue that the EIA study made unrealistically optimistic assumptions about the timing and scale of new nuclear capacity, carbon sequestration, and new renewable energy. [7] Under what it considers to be more realistic assumptions about the commercialization of new technologies, the NGC study estimated that natural gas consumption will increase by 20 percent between 2019 and 2030, whereas the EIA analysis shows a decline over the same period. The NGC study concluded that natural gas will be the most attractive fuel for power generation until carbon-constrained technologies become commercialized and economical, which may not occur until the 2020-2030 period. The natural gas industry has used the NGC study results to argue the urgency for accessing gas resources in offshore and other areas currently unavailable because of moratoria and other restrictions.[8] The industry warns

[5] The following link contains the NGC study: http://www.aga.org/research/studies/greenhousegasinitiativesanalysis.htm.

[6] Both studies used the National Energy Modeling System (NEMS) as their primary analytical tool. Differences in their outcomes mostly stem from the assumptions made by the study teams in providing input into the model.

[7] Regarding nuclear power, questions remain over its social acceptance and the construction costs of new nuclear plants, in addition to the still unsolved question of where and how to store nuclear waste storage. Regarding carbon sequestration, the technology for carbon capture and storage is still in the early stage of development, with some parts of the country lacking the geology suited to carbon storage.

[8] The Department of Interior's Minerals Management Service (MMS), as part of the Outer Continental Self (OCS) inventory requirement of EPAct 2005, has estimated the mean value of technically recoverable natural gas resources from federal offshore areas at 420 trillion cubic feet. (Technically recoverable energy resources are undiscovered resources estimated to exist in favorable geologic settings and producible with current technology. These estimates do not take into account the economic feasibility of developing these resources. Converting technically recoverable resources into economically feasible reserves requires detailed seismic work and exploratory drilling.) A recent study by the Interstate Oil and Gas Compact Commission estimated the technically recoverable resources in the federal OCS moratoria areas at 78 trillion cubic feet for natural gas. Moratoria areas, in other words, contain about 20 percent of the natural gas estimated to be undiscovered recoverable resources located in the OCS. If production from all of the estimated natural gas resources in "moratoria" areas occurs, i.e., assuming that all the technically recoverable resources were economically feasible reserves, these resources could meet the total U.S. demand for natural gas for over three years.

that unless the government removes these restrictions, new GHG legislation could result in sharply higher gas prices, which would impose significant harm on electricity consumers, as well as residential, commercial, and industrial gas consumers. The study does not offer a technical analysis of the extent to which moratoria elimination will affect prices.

2. A presentation by Jennifer Snyder of Wood Mackenzie[9] at this year's NARUC Winter Committee Meetings listed the following factors placing pressure on the U.S. for the future use of natural gas for power generation: pending GHG legislation, regulatory uncertainty toward the approval of new coal-fired plants, rising costs for new coal-fired generation, and declining reserve margins requiring new generation capacity. The presenter projects, at most, modest growth in coal-fired capacity over the next decade. Constraints in the building of coal-fired capacity will place additional pressure on the building of new gas-fired plants. This outcome will cause gas prices to increase and exhibit higher volatility. The presentation projects that GHG legislation will increase natural gas prices, but at a much lower level than what the NGC study projects. Similarly to the NGC study, the presenter predicts that generators will build new gas-fired plants as the technology of choice over the next decade. Two reasons for the attractiveness of gas-fired plants are their short lead time and the absence of viable alternatives. The presenter predicted three major effects of GHG legislation on the natural gas sector: (1) natural gas demand will rise strongly until around 2018, after which nuclear capacity additions will begin to displace gas; (2) natural gas prices will increase rapidly after 2011, but remain competitive with coal because of a carbon tax or allowance price; and (3) aggressive GHG-mitigation targets, and failure in the development of new generation technology, will result in additional pressure on future natural gas prices. She acknowledges that any prediction of natural gas prices is unreliable because of uncertainty over the exact specifications of GHG legislation and the development of low-carbon generation technologies. The presenter also raised concerns about the dependability of gas imports. She discussed the possibility that, in the long term, the U.S. will find it difficult to compete with other countries for LNG imports if oil prices remain above natural gas prices.[10] She also mentioned the likelihood that U.S. imports from Canada will decline sharply over the next several years (which is consistent with the latest EIA projections, *AEO 2008*). If these events occur, the U.S. will face the daunting challenge of meeting growing demand for natural gas (caused mostly by the increase in gas-fired generation) with fewer imports and stagnating domestic production.

3. A presentation by David Sokol of MidAmerican Energy Holdings Company proposed a three-phase GHG strategy, where a cap-and-trade system would not begin until 2017, at which time new carbon-constrained technologies could start replacing old technologies. He argues that most GHG legislation under discussion requires a reduction in CO_2 and a cap-and-trade system prematurely, prior to when new carbon-constrained technologies

[9] Wood Mackenzie is a consulting firm serving the energy industry.

[10] Other countries index LNG prices to oil prices, while the U.S. indexes LNG prices to gas markets such as the Henry Hub.

become commercialized. He says that this type of GHG strategy will cause a dramatic increase in the demand for gas-fired plants, sharply driving up the price of natural gas.[11] The presenter advocates what he calls a "glider slope" to allow a reasonable time for the development of carbon-constrained technologies that can "ramp down use of traditional energy sources." He supports an aggressive R&D program (which he likens to the Apollo program) that combines private and public funding at the level of $4 billion per year.

4. A presentation by Ellen Lapson of Fitch Ratings argues that, over the next five to seven years, the most viable option to expand needed generation capacity is the building of gas-fired plants. Partly for this reason, she expects future gas prices to continue on an upward trend and exhibit high volatility. The presenter predicted that new nuclear plants will be unlikely to operate before the period 2016-2020. She also placed little reliance on new coal-fired capacity over the next several years, in view of recent plant suspensions and cancellations. She noted the limitations of renewable energy's ability to add new capacity, given its intermittent supply. She mentioned the concern of local gas utilities regarding the tendency of gas-fired generation to aggravate tight supplies and high prices. She recommended that state commissions implement integrated resource planning and espouse a diversity of generation technologies, energy efficiency, and research and development funding and demonstration projects.

5. The EIA study on S. 280, published in July of last year, projected that the legislation would lower the total demand for natural gas.[12] This projection is in sharp contrast to other studies that show natural gas usage for power generation increasing. The study also projects that the GHG legislation would slightly lower the price of natural gas to residential and commercial customers because of lower demand. EIA projects that lower wellhead prices account for this drop in the delivered price; power generators and industrial customers, however, would pay a higher price for natural gas than they would absent the legislation because of the costs associated with GHG emissions allowances. Compared to other studies and analyses, over the period 2015-2030 EIA projected a much higher market penetration of carbon-constrained technologies for baseload generation, including nuclear power and renewable energy. The study concedes that if these projections overestimate the penetration of these technologies in conjunction with the replacement, on a large scale, of coal generation by gas generation, natural gas prices could increase dramatically. The latest EIA long-term reference-case projections (which assumes no major energy legislation and regulations, including GHG legislation), *AEO 2008*, show little change in gas consumption for power generation until about 2012, and

[11] He said that "[n]atural gas prices could easily jump to $15-$20/MMbtu, due to power plant consumption that increases from 6 trillion cubic feet (Tcf) per year to 25 Tcf."

[12] The reader can access the EIA study at http://www.eia.doe.gov/oiaf/servicerpt/csia/index.html.

then show a slow rise through 2016.[13] During 2016-2030, EIA projects a decline in gas consumption for power generation, with the gas market share falling from about 20 percent in 2018 to 14 percent in 2030.[14] Some analysts have recently questioned these projections, in view of the number of coal plant suspensions and cancellations that have occurred over the past several months.

6. The Electric Power Research Institute (EPRI) uses what it calls PRISM[15] and MERGE models to examine different futures in a carbon-constrained environment. EPRI's targeted or most preferred future, the "full portfolio," accelerates, over the period 2005-2030, the development of new carbon-constrained generation technologies—for example, greater new nuclear power capacity, the commercialization of carbon capture and storage (CCS) from coal plants, greater development of renewable energy, and advanced coal generation.[16] Compared to the EIA projections for 2030, and to what EPRI labels the limited-portfolio scenario, the full-portfolio future calls for much more nuclear power and renewable energy, more acceleration of energy efficiency initiatives, some advanced coal technology with CCS, and much less gas-fired generation. Under a full-portfolio future, only natural gas and non-captured coal would emit CO_2. EPRI calculated that under a limited-portfolio future, gas-fired generation would accelerate, increasing the use of natural gas for power generation by about 180 percent during 2005-2050. The full-portfolio future would lower significantly future electricity price increases, mainly due to much lower CO_2 emissions costs for the industry. EPRI argues that a large commitment to research and development activities by both the government and the private sector could accelerate the commercialization of carbon-constrained technologies and result in huge benefits for society. EPRI estimates that technology development that makes the full-portfolio future a reality could save society $1 trillion in reducing CO_2 emissions. The research organization argues that research and development funding should occur over a sustained period ($1.4-2.0 billion annually until 2030), with funding starting immediately.

---

[13] See http://www.eia.doe.gov/oiaf/aeo/index.html. Compared to AEO 2007, the latest projections call for much lower natural gas consumption in both 2016 and 2030, particularly in the industrial and electricity sectors. The reasons for the decline are higher natural gas prices (i.e., a price elasticity effect) and slower growth in electricity demand.

[14] The decline in gas-fired generation is offset by increases in generation from new coal, nuclear, and renewable energy plants.

[15] "PRISM" analysis determines the potential for reducing CO_2 emissions from a strictly technical perspective that deploys an advanced technology portfolio.

[16] For a description of the EPRI analyses, see http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2007-Fa/ll1016127.pdf.

III. Electricity-to-gas switching to achieve lower carbon levels

Another issue at hand is the question of the benefits of relying on natural gas for tasks other than power generation to achieve a carbon-constrained world. At least three speakers at the 2008 NARUC Winter Committee Meetings advocated switching away from electricity to natural gas for direct use applications. They asserted that converting from electricity to natural gas for water and space heating, for example, could produce substantial benefits to society. A major reason for these reductions is the much higher loss of energy in the production-delivery cycle for electricity than for natural gas. One presenter pointed out that the direct use of natural gas delivers 90 percent energy efficiency to end users, compared with a 27 percent end-use efficiency when natural gas is used to generate electricity. The same presenter also showed that the direct use of natural gas in home space and water heating results in 40 percent less CO_2 emissions than electricity.

One speaker, William Cantrell, President of TECO Peoples Gas Systems, mentioned the completion of a study in the next few month sponsored by the American Gas Foundation. A preview of the study, titled *Direct Use of Natural Gas: Implications for Power Generation, Energy Efficiency, and Carbon Emissions*, reveals the benefits of switching from electricity to natural gas for direct applications such as space and water heating. These benefits include a decrease in: (1) energy consumption, mostly from eliminating the high energy losses in producing electricity; (2) the need to build new generating facilities; (3) energy costs by end-use consumers; and (4) CO_2 emissions. The presenter showed that under different scenarios for technology development, gas supply conditions, and CO_2 restrictions, switching from electricity to natural gas for residential and commercial end-use applications would in each case reduce energy consumption, energy cost, and CO_2 emissions. Under one scenario with the passage of GHG legislation, energy cost savings could reach $29 billion by 2030.

Another presenter at the 2008 NARUC Winter Committee Meetings, David McClanahan, Chairman of the American Gas Association, listed as the gas distributors' number two priority the promotion of "direct use applications as the most efficient way to use natural gas."[17] He showed an illustration in which switching from electric to natural gas water heaters, on average, could save a residential customer about $220 annually on operating cost. He also showed that CO_2 emissions from natural gas water heaters are about 40 percent lower than those from electric water heaters.[18]

A third presenter, Ron Edelstein of the Gas Technology Institute, echoed the arguments of other presenters by offering evidence to support the use of natural gas for direct applications. He described the merits of natural gas, relative to electricity, for direct applications as "the energy source that provides the least costly, most efficient, lowest carbon-footprint solution to meet a given energy need." He added that, in the near term, the combination of aggressively promoting high-efficiency natural gas equipment and switching from electricity to natural gas for

[17] The number one priority is the promotion of energy conservation.

[18] This calculation assumes the production of electricity equally from natural gas combined cycle and coal-fired plants.

direct applications can produce large economic, energy efficiency, and environmental benefits. He, as did other presenters, emphasized the high energy losses resulting from electricity generation, relative to the much lower energy losses from the production and transportation of natural gas. The natural gas industry has for years argued that natural gas is much more energy efficient than electricity when accounting for the "full fuel cycle." Via pending GHG legislation, the industry is touting, in an aggressive manner, the direct application of natural gas as a low-cost approach to reducing CO_2 emissions.

IV. Questions for state commissions

The forgoing discussion raises several questions for state commissions. First, will GHG legislation lead to higher natural gas prices that impose a serious burden on electricity consumers, as well as residential, commercial, and industrial consumers of natural gas? The consensus among presenters from the natural gas industry is that more gas-fired generation will occur at least over the next five to ten years, with or without GHG legislation. Their argument is that the combination of electricity load growth, shrinking reserve margins, the near-term non-commercialization of clean coal technologies, the capacity limitations of renewable energy, the long lead time needed for new nuclear capacity, and the recent intense opposition to coal inevitably leads to only one outcome, the building of new gas-fired capacity. Less certain is what effect this additional demand for gas-fired generation will have on natural gas prices. The gas industry has taken the position that prices will increase dramatically. Other organizations, such as EIA, are more sanguine about the effect on natural gas prices. State commissions would like to know if they should expect the building of new gas-fired facilities over the next several years to have an adverse effect on consumers who use natural gas directly.

A second issue is whether state commissions should account for a possible natural gas-price effect when reviewing an electric utility's plans for new generation capacity. A price-effect refers to the rise in the market price of natural gas because of an increase in demand by the power generation sector. Economists call this phenomenon a pecuniary externality that has no net economic welfare effect; it does, however, when prices increase, have the effect of benefitting producers offset equivalently by the decline in consumer welfare. Although a single new gas-fired plant would not affect the market price of natural gas, the building of several new plants in a region and across the country could inflate natural gas prices. Should an individual state commission concern itself with such a price effect? Since the rise in natural gas prices around the turn of this century, we have seen state commissions challenged by falling gas consumption per customer (placing upward pressure on retail prices as fixed costs get spread over fewer sales), higher price volatility, increased customer arrearages and bad debt, and the unaffordability of gas service to low-income households. State commissions would see further natural gas price increases as aggravating these problems and leading to more difficult decisions.[19] They may, therefore, want to consider the effect of a proposed new gas-fired generating facility on the market price of natural gas.

[19] The growth of natural gas consumption for power generation in the 1990s contributed to the tight and volatile gas markets of the last several years. A more important factor in the

A third issue is whether a state commission should encourage fuel switching from electricity to natural gas for direct applications. If the evidence presented by the natural gas industry is credible, national and state policy goals of higher energy efficiency and a less-carbon environment would seem more achievable with a shifting of residential and commercial customers to natural gas for meeting their space and water heating needs. Should state commissions approve incentives or utility promotional activities to elicit customer fuel switching to natural gas from electricity? Another question is whether integrated resource plans should consider fuel-switching, since presumably it could have effects similar to energy efficiency initiatives.[20] Should a state commission, as part of a GHG strategy, actually prohibit the use of electricity for direct applications in new structures where natural gas would be preferable from both an economic and environmental perspective? A final question is why the marketplace has not produced more fuel-switching. Are there barriers to fuel-switching that state commissions need to address? Since some state commissions have approved utility incentives to promote energy efficiency, they may want to consider using incentives to encourage fuel-switching. The scenario of additional gas-fired generation in the near and long term offers strong support for promoting the wiser use of natural gas or energy efficiency. With growing demand and constrained supply, energy efficiency can play an important role in moderating future price increases, especially to offset the effect of fuel-switching and increased gas use for power generation.

A last issue is whether state commissions, individually or collectively (for example, through NARUC or regional collaboration), might want to encourage both the private sector and the government to expand R&D initiatives. A more aggressive R&D program could help to accelerate the development of new carbon-constrained technologies. Some analyses have shown that additional R&D could produce large societal benefits. The goal of these activities would be to speed up the commercialization of new generation technologies that could lessen the country's dependency on non-clean coal and natural gas.

---

recent phenomenon, however, is the rapid rise in costs for the exploration, drilling and production of domestic gas supplies.

[20] A paper written over fifteen years ago advocated the use of what the author called inter-energy integrated resource planning, where the challenge is "to bring the gas and electric utility planning processes together to the benefit of all." The paper, among other things, discussed fuel-switching strategies as providing a nexus between gas and electric integrated resource planning. See David M. Boonin, "Bridges between Electric and Gas IRP: Clean Air Act Compliance, NARUC's Fourth National Conference on Integrated Resource Planning, September 1992.