First Person—From "Moonbeam Gas" to Shale Revolution to What's Next

What Plentiful, Low-Cost Natural Gas Means for the Electric Power Sector

The Story in Brief

Vello Kuuskraa, President of Advanced Resources International and an internationally recognized expert on natural gas supply and markets, was among the first analysts to predict the North American fracking boom. Drawing from his deep understanding of natural gas resources and the technologies required to convert them into productive reserves, Kuuskraa speaks with *EPRI Journal* about the implications of the shale revolution for the electric power sector, the outlook for natural gas markets and prices, and how power companies can navigate potential price volatility.

EJ: How has your career shaped your current perspectives on natural gas supply and markets?

Kuuskraa: When starting my work on natural gas resources nearly 40 years ago, I wanted to better understand how progress in technology could change the size, productivity, and economic viability of resources and expand the natural gas market.

Vello Kuuskraa

My first major project was in 1978. It led to a three-volume report for the Energy Research and Development Administration (ERDA) on the status and potential of unconventional gas, which includes shale gas, tight gas, and coalbed methane. It examined how investments in research and technology could make these resources a bigger part of domestic supply.

The following year, my company provided much of the geological foundation and reservoir engineering to help ERDA and the Gas Research Institute implement numerous field demonstrations that enabled these resources to become economically viable. The projects included coalbed methane in Alabama and New Mexico, tight gas in the numerous basins of the Rockies, and the shallow Antrim

Shale in the Michigan Basin. A crowning achievement was my work with Mitchell Energy on the Stella Young #4 well. This Barnett Shale well in Texas demonstrated that if you increase contact with a natural gas reservoir using a slant or horizontal well and shatter the reservoir with high-intensity hydraulic fracturing, you could make deep shale gas resources much more productive and economic. The Stella Young #4 was three times more productive than the previously drilled Barnett Shale wells. Then I helped Southwestern Energy make the next major shale play, the Fayetteville Shale, commercially viable.

EJ: You were among the first analysts to predict the natural gas fracking boom in North America. How did you see it coming, and how did others in the natural gas industry react?

Kuuskraa: Through the Gas Research Institute demonstration projects and later engineering and geological services for the natural gas industry, I had the benefit of seeing firsthand the results of properly applying hydraulic fracturing and horizontal wells to coalbed methane, shale gas, and tight gas resources. I also knew from my company's extensive set of basin-by-basin, play-by-play resource assessments that the unconventional gas resource base was massive.

In the early 1980s, I built my company's unconventional gas resource, economics, and production model with two unique attributes—fine-grained resource data and an ability to project impacts of advancing technology on future well performance and costs.

In the 1990s, when I began presenting our natural gas outlook under the headlines "The Future is Unconventional" and "Progressing from Fears of Scarcity to Expectations of Plenty," there was considerable skepticism. Some attendees at an industry conference even called these unconventional resources "moonbeam gas." Much of this attitude was from other energy forecasting firms and industrial companies that had bought into Alan Greenspan's guidance that massive imports of liquefied natural gas would be the only solution to the upcoming natural gas supply crisis. With natural gas demand increasing and offshore wells and other domestic conventional resources getting depleted, others in the industry didn't believe unconventional gas could fill the gap.

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EJ: How has the shale gas revolution affected the U.S. power sector's natural gas consumption? What do you see for future demand?

Kuuskraa: With increased availability of lower cost natural gas supplies and emphasis on lowering CO_2 emissions, the use of natural gas in the U.S. electric power sector jumped from 17 billion cubic feet per day (Bcfd) 10 years ago to more than 27 Bcfd this year, making it the largest fuel source for power generation. With nearly 20 gigawatts of new natural-gas-fired capacity due to come online in the next three to four years—mainly to replace older, less efficient coal units—I expect continuing growth in natural-gas-fired power generation, though at a less spectacular pace than in the past decade.

Still, I see considerable uncertainties for the outlook for natural gas use by the power sector. These include the timing for implementing the Clean Power Plan, the extent to which natural-gas-fired capacity will be needed as backup power for intermittent wind and solar generation, and the reliability and affordability of carbon capture and storage technology to make natural-gas-fired plants a zero CO_2 emissions source.

With continuing changes in the sources and locations of new supplies, I expect power companies to follow a variety of strategies to integrate with natural gas supply to support its reliable delivery to power plants. Recent examples include Southern Company's purchase of AGL Resources, the largest natural gas distributor in the

United States; Southern Company's acquisition of half of Kinder Morgan's Southern Natural Gas; and Duke Energy's proposal to acquire Piedmont Natural Gas. Other power companies may look to purchase or build natural gas storage and potentially even acquire production assets as hedges against future price volatility.

EJ: How does natural gas consumption in the electric power sector vary regionally in North America?

Kuuskraa: The South, even with substantial coal and nuclear plants, is the "600-pound gorilla" of natural gas consumption for power generation, using more than 16 Bcfd to generate more than 40% of its power. With significant nuclear and hydropower and a history of limited, higher cost natural gas before the onset of the Marcellus Shale, the Northeast offers growth opportunities when pipeline restrictions are overcome. The Midwest is still dominated by coal-fired power generation, with natural gas accounting for only 15% of generation, but the increasing westward flow of low-cost Marcellus and Utica shale gas makes this market ripe for expansion. The West—with low-cost coal, substantial hydropower, growing wind and solar power, and increasingly stringent carbon regulations in California—uses nearly 5 Bcfd of natural gas to generate about 30% of its power. It represents a challenging market area unless natural-gas-fired power can achieve zero CO_2 emissions with carbon capture and storage.

With the installation of new pipelines and the reversal of northward-flowing pipelines to move Marcellus and Utica gas south, I expect the Southeast to provide the bulk of the next phase of market growth for natural-gas-fired power generation.

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EJ: What are the risks of the electric sector becoming more reliant on natural gas?

Kuuskraa: Today's low-cost natural gas resource base and price situation is very different from those at the turn of the millennium when new gas-fired plants were stranded by high gas prices. Back then, new supply from offshore deep water resources and exploration for conventional gas fields had long lag times, resulting in extensive periods of price volatility. Therefore, a significant rise in natural gas prices was needed to bring on additional supply, drive down demand, and balance the market. Today, the large, lower cost shale and other unconventional gas supplies, with many active wells, can be brought to market much more quickly—within months instead of years. This reduced the lag between price signals and availability of new supply and decreased the need for longer term price increases to drive out demand. Periods of price volatility will be shorter than in the past. As a result, electric utilities that rely more on natural gas have lower supply and price risks now than they did 10–15 years ago.

To better understand this risk, it's critical to understand the nature of the natural gas cost-supply curve that sets long-term prices. Our company's approach has been to build a natural gas supply resource database characterizing the diversity of all the natural gas basins, plays, and smaller areas within plays in North America, including their break-even prices and resource volumes. This enables us to define a natural gas cost-supply curve comprised of nearly 1,000 distinct segments. We link our detailed database to our technology progress, resource depletion, and economic models to capture the dynamic nature of production, enabling reliable supply and price projections with fine-grained local and regional detail. Electric utilities can manage and reduce price and supply risks by understanding the natural gas cost-supply situation in their regions, and by integrating power plants with appropriate natural gas transportation, storage, and supply.

EJ: During the polar vortex of 2014, regional constraints in natural gas supply and distribution led to price spikes and strained U.S. power systems. How do you expect such events to impact the natural gas–electric interface?

Kuuskraa: There will be unexpected events, such as another polar vortex, that will stress the U.S. power and natural gas supply systems and create price volatility. In my view, however, these periods of price volatility will be much shorter than in the past because of the different nature of today's natural gas resource base, as I previously discussed.

Again, closer integration of power plants with natural gas transportation, storage, and supply can help power companies avoid shortages and manage price volatility.

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EJ: How do you expect North American natural gas production, demand, and prices to change over the next 10 years? Are there factors that could cause price volatility?

Kuuskraa: With modest increases in natural gas consumption by the electric power and industrial sectors, plus strong increases in pipeline exports to Mexico, and liquid natural gas exports to other countries, I expect a significant increase in demand for U.S. natural gas—10 Bcfd over the next 10 years. The resource base is sufficiently robust to meet this demand without excessive price increases.

A number of factors will affect the efficiency with which supply and demand are balanced. One is the amount of natural gas produced from tight oil formations, which represents 20% of total U.S. natural gas production. Continued low oil prices will result in lower natural gas production from these formations and therefore less supply and higher prices. Having a reliable outlook for oil prices now becomes important for domestic electric power companies. A second factor is the availability of natural gas imports from Canada, where a similar unconventional gas revolution has dramatically expanded supply. In my view, this will enable Canada to continue providing significant exports to the United States.

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EJ: In the media, we can find many expert projections about natural gas prices. How can nontechnical readers view these with a critical eye?

Kuuskraa: Projections for prices range from "low forever" to "sharply rising," causing considerable uncertainty for nontechnical and technical readers. Some of this reflects valid uncertainties, but many "flavor of the month" projections reflect emotion and hope rather than analytical rigor. To help decide which experts to trust, readers should look at their track records—have their projections generally been on- or off-target? Readers can also evaluate the consistency of an expert's projections. Do they fluctuate dramatically from month to month, or do they provide a consistent year-to-year trend with accommodations for short-term price volatility? This will help the reader understand if there is analytical rigor and a valid supply-cost curve behind the projections. When a projection changes, does the expert provide a sound rationale? Finally, is the expert neutral, or does he have some "skin in the game"?

EJ: What research is needed to help U.S. electric utilities determine the most reliable, cost-effective use of natural gas?

Kuuskraa: One key area is assessing the North American natural gas supply-cost curve and how the race between the competing forces of resource depletion and technology progress is playing out in different areas. Also important is gauging the extent to which deployment of intermittent wind and solar generation will require closer integration with natural-gas-fired generation. The power industry can also benefit from examining the benefits, costs, and risks of greater integration of electric power generation with natural gas transmission, distribution, storage, and supply, and from sponsoring research and field demonstrations of CO_2 capture and storage from natural-gas-fueled power plants.

The views and opinions in this interview do not necessarily reflect the views of the Electric Power Research Institute.

EPRI Examines the Electric–Natural Gas Interface

Natural gas markets are rapidly changing, and EPRI is building an advanced model to better understand the drivers and dynamics of supply, demand, and interregional delivery. This project will assess energy and environmental policy proposals related to natural gas and inform utility investment decisions on new natural-gas-fired generation, environmental retrofits, and additional natural gas delivery capacity.

EPRI's Environment Sector offers EPRI members the opportunity to participate each year in a Natural Gas Interest Group—a collaborative forum for power companies to improve their understanding of the supply, demand, and pricing of natural gas and the implications for the electricity sector. Participants learn about relevant research at EPRI and elsewhere, discuss emerging natural gas–electric issues, and have opportunities to engage with regulators, developers, and scientific, engineering, and environmental organizations.