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Natural Gas Market Outlook

Gas Positioned To Displace Coal Plants

By Vikram Rao

RESEARCH TRIANGLE PARK, N.C.–When natural gas is combusted for electric power production, the amount of carbon dioxide produced is about half that from coal-fired electric generation. Beyond this, the environmental externalities associated with natural gas are small when compared with those attributed to coal consumption, notably mercury, sulfur and nitrogen-oxide emission possibilities, and less noticeably, fly ash disposal problems.

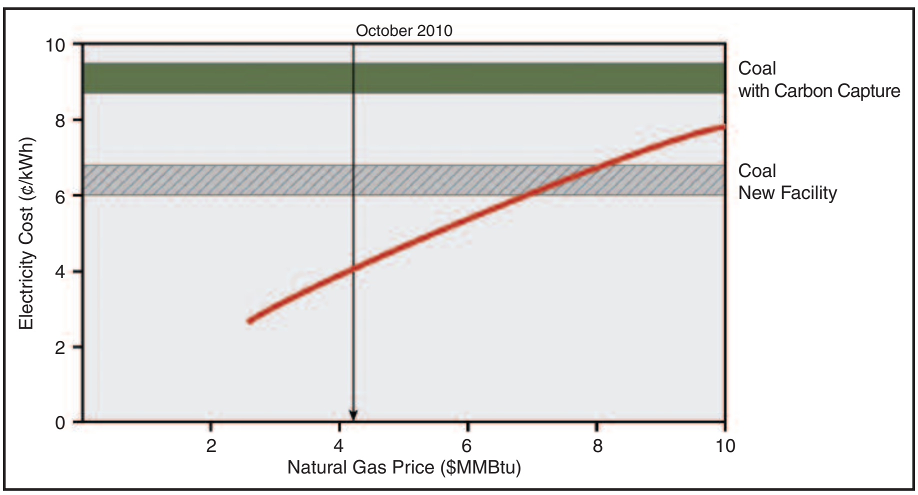
A decided shift toward natural gas stalled in the early 2000s when gas prices became unpredictable. The shift started when gas was priced around $2.00 an MMBtu and the all-in cost of electricity production was less than with coal. In the latter part of the past decade, a quandary was reached where although natural gas prices were increasing, so were construction costs for coal plants. This inevitably led to a large number of planned coal plants being postponed.

Today, Congress has reached no consensus on legislation to mitigate carbon emissions and the new shift in political balance makes that prospect less likely. The bottom line is that a price on carbon is unlikely in the near future. The European version of cap-and-trade simply has not worked. The price has fluctuated, and uncertainty in price dampens investment because there is no choice but to make the discount rates higher. That raises the overall cost of investment. A price on carbon much less than $40 a metric ton will have little effect because of the cost of sequestration.

However, the U.S. Environmental Protection Agency is expected to levy strong restrictions on mercury, sulfur and NOx. One report states that more than 40 percent of coal generation plants that do not meet these standards are 50 or more years old. One can reasonably expect many of these to be mothballed, leaving room for either new coal plants, new gas-fired plants or alternative methods such as nuclear, with the problem exacerbated as the global economy continues to expand.

FIGURE 1

Electricity Cost as a Function of Gas Price



With gas plants less costly to build, cheaper to operate (at forecast gas prices), and easier to obtain regulatory approvals on new construction, the bias toward gas power generation will be significant. The lead time to first electricity production is also low for gas compared with either coal or nuclear.

The catastrophe in Japan and the reported problems at the nuclear plants will have a chilling effect on the nuclear option. Switzerland already has put a freeze on new plant permits, and Germany is discussing going back on an agreement to extend the life of existing nuclear plants. All this occurred within days of the events and with no firm finding regarding the true impact. No one is seriously considering wind or solar for base load any time soon.

Cost Variables

However, coal and gas are polar opposites with respect to cost. For coal, the capital cost is a high proportion of the all-in cost (around 60 percent), while the commodity is relatively stable. In 2010, coal varied little, costing about $2.25 per MMBtu. This is the best way to express the cost of coal because the Btu content is highly variable. In fact, the BTU content differs by more than a factor of two from brown coal to anthracite. So in comparing with other fuels, the price per ton is not a meaningful figure, even though it often is quoted.

Gas-based power, on the other hand, has a relatively low capital cost (around 15 percent), but it has had a highly variable price in the recent past, at least over the lifetime of amortizing equipment. Consequently, while coal power is highly susceptible to construction costs and inflation in general, gas economics depend primarily on the price of the commodity.

Figure 1 plots the all-in cost for power produced from natural gas as a function of gas price. The figures are from a Bernstein Research report and reflect 2006 economics using the October 2010 average price (the most recent month available). Price was episodically over $5.00 during the year and also below $4.00.

The generally accepted cost of production from new coal-based construction meeting emission standards is drawn as a horizontal band between $0.06 and $0.065. The impact of a price on carbon can be treated in one of two ways. Post-combustion capture with technology that is known but not yet perfected can be expected to cost $0.03/kilowatt-hour to reduce the carbon dioxide to comparable natural gas levels. This is plotted as the second horizontal band above the first. The second way to treat it is to simply pay the carbon penalty. At a price of $25/ton, this would add $0.01/kWh. This accentuates the point that any price less than $40/ton is simply not reflective of the cost of taking out the carbon.

Of immediate note is that in late 2010, the gas-based cost was well below that of a new coal plant. In particular is the observation that the break-even with coal kicks in at a natural gas price between $7.00 and $8.00/MMBtu. This is without considering any carbon penalty. If that is included, the break-even moves to a gas price between $9.50 and $12.00/MMBtu, depending on which model of carbon penalty one uses. The memory of the natural gas price spikes of several years ago still endure, but the fact is that prices were above $12.00/MMBtu for only about four noncontiguous months. The predictability of price and assurance of supply are needed for a major shift from coal to gas.

Supply Assurance

A scant three years ago, the issue of supply assurance would have had a different answer. Any discussion would have involved liquefied natural gas imports and the environmental risk posed by importing LNG. Shale gas has changed all of that. The United States can expect to be self-sufficient for 100 years.

This also could change the entire debate around natural gas in Prudhoe Bay. Natural gas in copious quantity has been reinjected because of the high cost of a pipeline to the lower-48. Under the circumstances, the industry dodged a substantial bullet by the delay in that decision. Had a pipeline been built, the fully loaded cost of the gas would have been challenged by that of shale gas production and utilization could have plummeted.

As an alternative, the nation could reopen the possibility of exporting Alaskan North Slope gas as LNG, which had been politically impossible in the past because of the net U.S. supply shortage, with the exception of a single permit for exporting Cook Inlet gas as LNG. That should no longer be an issue. In fact, ConocoPhillips has sought an extension to the Cook Inlet permit. Shale gas from the Horn River Basin in British Columbia already is slated for LNG export by Apache Corporation. Gas exports from North America could become a trading force.

In regard to future gas prices, the floor will be determined by demand. Last year, prices hovered around $4.00/MMBtu even without demand creation. A shift from coal to gas obviously will drive demand. So the concern is likely more at the upper end. Is there a mechanism for a ceiling? The answer is affirmative, and it results from the setting in which shale gas is found.

Most shale gas is either proximal to the intended market, as in the case of the Marcellus, or close to major pipelines, as in the case of the Barnett, Haynesville and Woodford, to name three big ones.

Compared with conventional gas, shale wells are relatively shallow and on land. One study conducted a year ago examining 100,000 wells showed that the average drilling time for a horizontal well from spud-to-spud was 27 days. With the steep learning curve this industry is accustomed to, these numbers have doubtless improved even more over the past year. In fact, shale gas is particularly advantaged in this respect because the sheer numbers of wells allows for innovation to be perfected in what amounts to a "gas factory" manufacturing approach.

From Spud To Sales

However, the time from spud to gas sales has been much greater, averaging closer to 150 days a well. It varies by shale play, but curiously, the Haynesville–with the longest drilling times because of the depth and complexity of the wells–has the shortest time to market at about 90 days.

The concept of drilling 15 or more wells from a single pad was pioneered in Colorado as an environmentally friendly technique. However, this may be the culprit for the long time to market, because it allows wells to be drilled and completed in batches. This necessarily greatly increases the time from first spud to first delivery. That said, this technique is likely here to stay, particularly in heavily populated areas of the Marcellus. It dramatically reduces the traffic associated with pump trucks, proppant delivery, water disposal, etc. The aggregation also permits higher levels of sophistication in areas such as water handling, remote decision making and quality control. Ultimately, operators will balance the economics of batch operations against the opportunity cost of later deliveries.

Depending on the area and the business drivers, new production can be brought to bear in as little as 60 days, and certainly within 180 days. This is compared with more than four years for a conventional offshore gas field. This short time span basically will keep a lid on the high end. Speculators will be aware of the industry's quick-response ability. This throttle effect likely will keep prices under $8.00, and possibly closer to $6.00/MMBtu. This is the crux of the thesis that shale gas will enable natural gas to remain within a tight band between $4.00 and $6.50 for a long time.

At numbers north of $4.00/MMBtu, most operators will make a very good profit, especially if a portion of the gas is condensate-laden. Newer technologies will continue to drive down cost, as has been the case in every new resource play since Colonel Drake's find. So the businesses will be sustainable and continuous supply will be assured (it should be noted that LNG imports have a built-in transportation cost of $3.00-$4.00/MMBtu over and above the production cost).

Environmental Concerns

The favorable economics notwithstanding, freedom to operate considerations centered on environmental issues merit discussion. The concerns all relate to water issues. In the early going, frac chemicals were a big concern, largely because of the industry's reluctance to disclose details on frac fluid constituents. In actuality, the concentration of chemicals in shale gas frac water is less than 0.5 percent and often less than 0.1 percent.

Consequently, combined with eliminating the bad actors such as BTEX (which really are not needed), and substituting greener ingredients in general, the frac fluid chemicals issue essentially should go away. However, industry will need to continue doing its part by being transparent and proactive in educating the public.

The real issues will center on three areas: freshwater withdrawals for operations, frac flow-back water, and produced water handling and disposal. The last area, of course, is common to all petroleum operations, and not just shale gas.

Much also has been made of well water contamination. The industry is aware that this can happen only because of poor practices. Adherence to good practices, possibly combined with some level of monitoring and oversight, should make this issue go away, at least in real terms–award-winning documentaries notwithstanding.

A horizontal shale well with multiple completion stages typically uses 3 million-5 million gallons of water, and freshwater routinely has been used as the base fluid. Shale operations are somewhat unique in that only 25-35 percent of the water returns during production, and the rest remains in the formation. Also, the flow-back water is almost always more salty than what went in. Disposal has been an issue in terms of cost and allegations of improper discharge.

The key to addressing this issue is the ability of the frac water to tolerate some level of chlorides. Research has shown that not only is this possible, but that it can be beneficial. The chlorides actually stabilize the clay constituents of the shale and improve production, although companion chemicals such as cross-linkers and friction reducers may need to be modified.

This has two possible implications to water withdrawals. The first is that after some measure of treatment, the flow-back water should be usable. But withdrawals for makeup water will be necessary. This is where the second implication comes in. It should be possible to get moderately saline water from another source, since salinity is tolerable. The key here is that flow-back water could, and over time should, be completely reused, thereby creating a zero-discharge scenario.

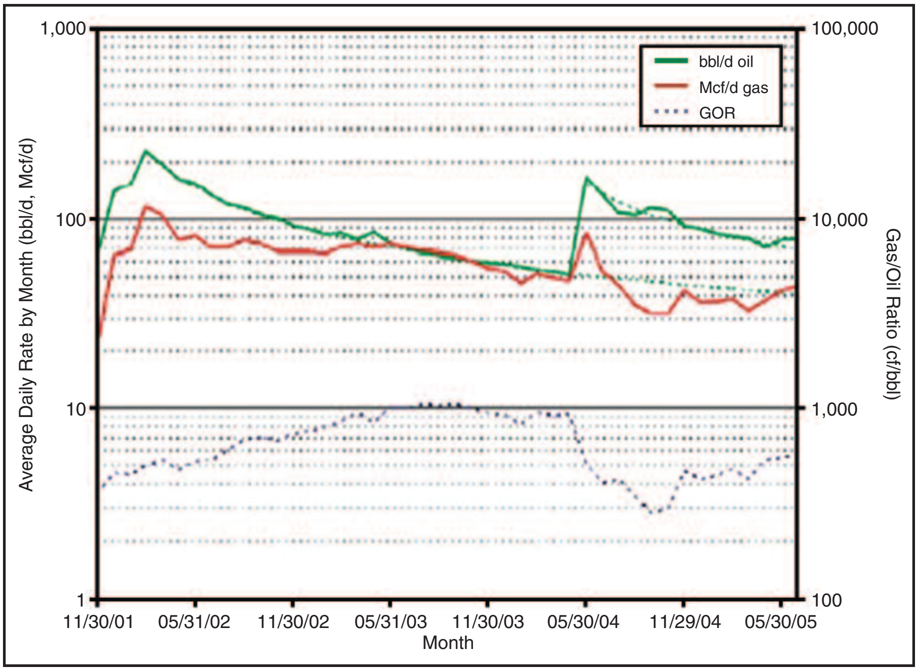
Today, the industry can likely tolerate 40,000 ppm chlorides. If flow-back water comes in higher, it will need to be desalinated to some degree or diluted by freshwater withdrawals. In some parts of the country, the latter operation likely is completely feasible. Another option could well be to use seawater as the water of convenience. Seawater averages 35,000 ppm chlorides. That already is in the range of acceptability with the possible removal of some minor constituents such as divalent ions.

Finally, there is the option of producing from saline aquifers, as is being done already in some cases. Saline water wells drilled as companions to gas wells are very likely in areas with challenging surface water availability.

Eventually, one could expect the industry to develop fracture fluids tolerant of even higher salinities. That would open some very interesting outcomes. Today, seawater and brackish water reverse-osmosis plants have a problem waste that comprises brines with 75,000 ppm dissolved solids. This waste now could be usable by the drilling industry.

FIGURE 2

Example Refracturing Results



Decline Rates

Shale gas wells certainly appear to decline more rapidly than conventional wells. In the first year or two, the decline is hyperbolic and then goes asymptotic. There are two possible solutions to this. One is to figure out the mechanism and ameliorate the effect. One theory is that proppant sand does not penetrate far into the formation because of the low density of the slick water, resulting in gradual closure of the fractures with an attendant permeability stage.

One possible remedy is using low-specific gravity proppants, although the cost/benefit would be a driving factor. Another avenue would be to radically rethink the problem and assure flow through some completely different mechanism for keeping fractures open. The general take-away is that these are early days in shale development and mechanisms continue to be better understood, and ingenious solutions for improving productivity are very likely.

Refracturing is an example of a technology that already is overcoming early declines, initiating new fractures in well bores, often directly on top of the old ones. In the few cases where it has been attempted in the Barnett Shale, the results have been dramatic.

Initial refrac production rates have reached and exceeded the original IPs. Sometimes, they decline at the same rate as before, which is generally the case in the example shown in Figure 2. This is in-

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dicative of the possibility that new rock pores are being accessed, and in fact, the results in the figure suggest that the refrac contacted previously undrained portions of the reservoir. Research is ongoing and one can expect results to be variable for some time.

The success of refracturing may be perversely based on a shortcoming of the resource: poor reservoir permeability. Ordinarily, poor permeability means less flow, and hence, less production. Fracturing improves that. But if the fractures are imperfect, the gas in the stimulated reservoir volume does not get fully drained.

However, the gas is available for new fractures, and is for all practical purposes, from new rock despite being proximal. From the standpoint of the economics of the prospect, all that matters is that each operation causes enough production to assure a rate of return. The fast declines are not highly material if this threshold is met. One final point is that refracturing costs a fraction of the original well cost.

In summary, shale gas has changed the game for the natural gas industry as well as the power generation sector. For the first time in memory, a major fuel can be predicted to price in a tight band at low to moderate levels for many years, and it can be sourced 100 percent domestically. This is the type of certainty that drives investment. The timing of the realization is impeccable in dealing with upcoming EPA regulations on coal power plant emissions and possible ones on CO_2. No new coal generation plants are economically justifiable. ❒