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GENERATION
THE EMERGING NATURAL GAS CRISIS
By Andrew Weismann

After two back-to-back years of financial turbulence, the U.S. energy industry is about to face another momentous challenge: a multi-year period of far higher than predicted natural gas prices, heightened price volatility, and extraordinarily tight supplies. And this is likely to persist for much of the rest of the decade. In many regions, it will be accompanied by an equally steep rise in electricity prices, especially during the summer months.

The causes of the current crisis are deep-seated. It stems first from the march to build more (gas-fired) generation. From there, you could say that gas has fallen victim to extraordinary events—but we're only beginning to feel the repercussions.

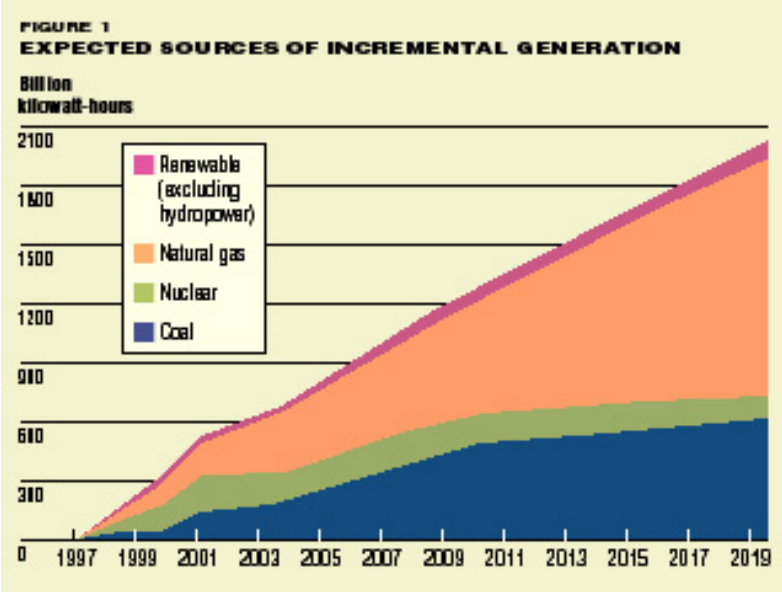
Build, Build
In the 1990s, most regions of the country saw the need for new generation. Reserve margins also began to fall to unacceptable levels. As a result, for the first time in more than two decades, every region of the country needed to add significant amounts of new generating capacity.

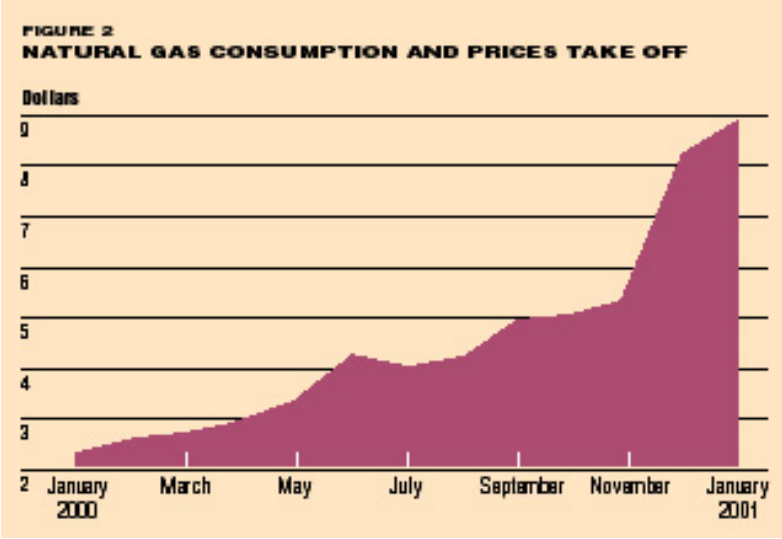
This was accompanied by a shift to gas-fired generating units as the near-exclusive source for new capacity. The shift occurred for many reasons, but the most important were the Clean Air Act and its Amendments. It was widely recognized the 1990 Amendments were likely to put significant upward pressure on natural gas supplies. Most expected U.S. demand to increase to at least 30 trillion cubic feet (TCF) a year, with an accompanying increase in prices to at least $3-$4 per million British thermal units (MMBTUs) in 1990 dollars (the equivalent of roughly $4.25-$5.50/MMBTUs today).

The power industry responded by undertaking one of the most massive construction programs in U.S. history. In fewer than four years, more than 200,000 megawatts (MW) of new capacity came on line at a cost of more than $100 billion—enough to serve almost half of current European needs and rivaling the total amount of

generating capacity in the world outside of the United States and Europe. With only a handful of exceptions, virtually all these units were gas-fired.

Many of these units will not be fully used for several years. Still, the United States counts on expanding their use to meet the economy's incremental electricity needs for many years. (See Figure 1.) In its most recent forecast, the Energy Information Agency (EIA) projects total demand to grow by more than 30 percent over the next 20 years.





At the time many of these units were built, there was little reason to doubt the ability of the exploration and production (E&P) industry to supply the natural gas those units required. The price for gas had been declining in real terms for years.

Further, prior concerns regarding long-term adequacy of supply consistently had been proven unwarranted.

Beneath the surface, however, a more complex picture emerged. While prices for natural gas had remained relatively stable, demand

also was flat during the last half of the decade (due mostly to a string of unusually mild winters). As a result, the E&P industry's ability to expand supplies of natural gas significantly and rapidly had not recently been seriously tested.

On a more fundamental level, however, there was mounting evidence that, after 20-30 years of intensive development, some of the largest fields in the United States and Canada were beginning to tire. Onshore production in Texas, Louisiana, and Oklahoma (the three largest gas-producing states), for example, had hit a plateau. In fact, production also began to decline rapidly in portions of both Oklahoma and Texas. For several years, this decline had been largely offset by increased production from the near-shelf region (shallow waters where the drilling is at depths of no more than 656 feet) in the Gulf of Mexico. By the mid-1990s, however, production there also had begun to decline. Losses in production from these conventional sources were replaced by deepwater drilling (at great cost) further out in the Gulf and rapid expansion in Canadian imports. By the end of the decade, there were increasing signs that the rate of growth in supply from both was leveling off.

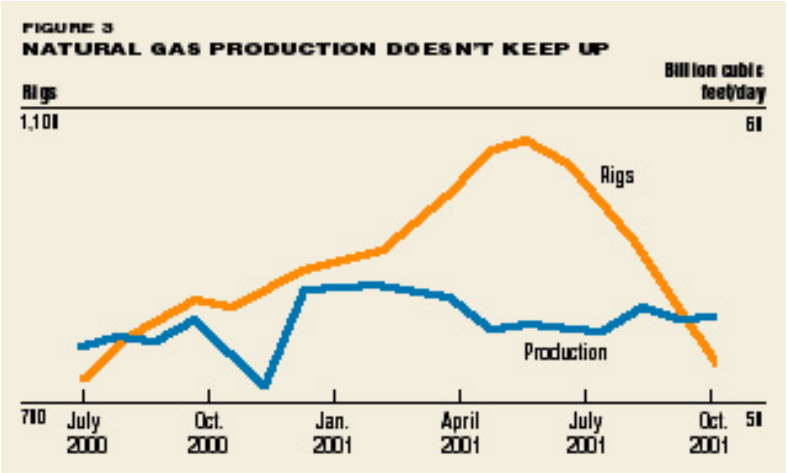
The Emerging Supply Crisis

Few industry observers anticipated what has transpired over the past 36 months. In 2000, winter temperatures returned to more normal levels for the first time in several years, and the use of natural gas for electricity began to take off. The impact on gas prices was immediate and severe: Prices quadrupled in less than 12 months, reaching $10/MMBTU in December 2000 and averaging well above $8/MMBTU for more than two months. (See Figure 2.)

As one might expect, the E&P industry responded with a massive increase in development activities. Between mid-2000 and mid-2001, more than twice as many new wells were drilled than just two years prior, with almost every available rig in North America actively deployed in the field. Spending increased by at least $10 billion-$15 billion in a period of just 12 months.

In response to this unprecedented ramp-up, however, production barely budged. Even at the peak of the cycle, production never increased by more than 1.4 billion cubic feet (BCF) per day—an increase of about 2.7 percent, or less than half of the increase in consumption that occurred over the same period. (See Figure 3.)

As more new wells were drilled, it became clear that they were needed simply to replace the rapid decrease in production from existing wells that was occurring as major U.S. fields aged. In hindsight, the inability to expand production when a multi-year increase in demand for natural gas was expected should have raised some flags.



When the E&P industry ramped up drilling in 2000 and 2001, it was not exploring new ground—either literally or figuratively. Instead, companies typically were drilling in basins (under development for many years) with the benefit of improved seismic technology that provided a more accurate picture of developing reserves than had been previously available. The developers also had every incentive to maximize returns on their investments.

There is every reason to believe, therefore, that the E&P companies used their resources wisely and efficiently and achieved the maximum increase in production that reasonably could have been expected given the timeframe and expenditures involved. The minimal production increase achieved as a result of this massive effort does not bode well for the E&P industry to meet the current need for additional natural gas supplies.

Flaws in Conventional Wisdom

In the immediate aftermath of the late 2000 and early 2001 price shocks, relatively little effort was made to understand their causes or future implications. Given the events of 2001 and 2002, the absence of such an examination is hardly surprising—to say the least, there were enough urgent issues to occupy the full attention of most companies.

Furthermore, at least superficially, the price spike appeared to be short-lived. Prices remained well above $5/MMBTU until late April but soon fell. By January 2002, prices were again at the $2.25/MMBTU level, exactly where they had been 24 months earlier when the cycle first began.

Many drew the natural conclusion that the run-up was just another (albeit more extreme) example of the boom-and-bust cycle that has plagued the E&P industry for years. The conventional wisdom has been that, in response to higher prices, production rapidly increased and demand quickly dropped, bringing prices right back to prior levels. Many also believed that the 2000-02 cycle was proof that when price spikes occur, market forces quickly bring them back to an equilibrium.

But as we have seen, while the E&P industry reacted to the spike

with more development activity, the resulting increase in production was anemic at best.

Further, while natural gas users clearly reacted to higher prices, the response was more complex than many analysts recognized. During the first four months of 2001, consumption actually increased relative to the same four months in 2000, even though prices were 2-4 times as high.

Consumption did not begin to fall until later in the year after prices began to drop rapidly. On a year-over-year basis, during the period between April 1, 2001, and March 31, 2002, U.S. consumption declined by 2.2 TCF relative to consumption in the prior 12 months. It was this record drop, not the meager increase in production, that caused the decline in prices during the second half of 2001 and the accompanying huge build-up in storage. The more prices dropped, the more consumption dropped. (See Figure 4.) Further, consumption began to increase immediately after prices began to rise.

This extraordinary sequence of events, in turn, is attributable to the unique combination of events in 2001 and early 2002, not to any long-term stable equilibrium between supply and demand. These events included: the worst manufacturing recession in 22 years, the September 11th attacks, Enron's collapse, and one of the mildest winters in years. All these factors had the effect of significantly reducing demand in a single, compressed time period—with the mild winter weather during the 2001-02 winter heating season being the most important factor. In effect, it was almost as if winter never arrived; as a result, the usual winter season drawdown from storage never occurred.

Causes of the Current Crisis

The collapse in prices forced the E&P industry to cut back sharply on drilling of new wells, clearly one of the factors that is bringing about the current crisis. (See the sidebar, "No Magic Bullet.") It is important to recognize, however, that while drilling is currently well below the 2001 peak, it is only modestly below levels that were typical during the 1990s. It would be a mistake, therefore, to see the current crisis as a short-lived phenomenon that results primarily from a temporary decline in drilling in 2001 or 2002.

Instead, over the past year it has become increasingly apparent that the E&P industry has reached a point of diminishing returns, in which it is no longer likely able to significantly expand production from conventional sources in the United States and Canada.

This does not mean that the United States or Canada is running out of natural gas; instead, at least on paper, there clearly are ample supplies in the ground to meet the needs of the U.S. market for many years. At the same time, however, with each passing year, the fields continue to age.

- The decline rate (the rate at which the industry loses production from existing wells) is increasing every year, with more than a 50-

percent increase over the past five years in the new supplies that must be produced each year to offset the loss in production from existing wells.

- The size of a typical new well has been declining rapidly.
- The break-even cost required to justify new drilling has been increasing every year.
- The half-life of a typical well has dropped rapidly—to the point that it now is necessary to drill one new well every 12 months just to replace the loss in production that is expected to occur from every two new wells drilled during the prior 12 months.

As a result of these factors (coupled with the slowdown in drilling), U.S. production has been declining significantly every quarter for at least eight consecutive quarters and is likely to continue declining through the remainder of this year, even if the pace of drilling picks up. For the year, total U.S. production in 2003 is likely to fall to its lowest level in 16 years. Further, Canadian imports have begun to decline, and the United States has begun to export significant amounts of natural gas to Mexico (largely to serve new gas-fired plants built there, which serve the U.S. market). The net impact of these factors is to create an unprecedented structural deficit, with total supplies of natural gas available to the U.S. market in 2003 likely to fall as much as 1.5-2.0 TCF below EIA's most recent forecast of demand for the year.

Early Warning Signs

The first clear warning signs of the current crisis emerged in the second half of last year. Beginning in February, the amount of natural gas in storage declined every month, compared to five-year average levels. For a time, these declines were largely ignored, since the amount of natural gas in storage remained above historical norms. Declines of this magnitude only could have occurred, however, if the rate at which new supplies were being delivered to the U.S. market were continuing to fall further behind current monthly consumption levels.

With the 2002-03 winter heating season, the rate of decline in storage began to accelerate sharply. By mid-January, weekly withdrawals were averaging as much as 50-75 BCF per week greater than might be expected on a weather-adjusted basis, if supply and demand were in balance for the year. This equated to a deficit of as much as 7-10 BCF per day. By the end of the winter heating season, storage had dropped to all-time record lows. This in turn set the stage for continued upward pressure on natural gas prices until at least the end of October, as local distribution companies and their suppliers struggled to rebuild storage to adequate levels in anticipation of the next winter heating season.

Fundamental Challenge

The initial reaction of many in the industry has been to attribute the record withdrawals from storage this past winter to colder-than-normal weather. In fact, however, while the tail end of the winter was especially cold, temperatures as a whole almost precisely equaled historical norms. This winter represented a return to more normal conditions, therefore, not an aberration.

Over time, a ramp-up in drilling of conventional wells and accelerated development of coal bed methane will help to rebuild supplies—at least to a degree. Given the lead times involved, however, it is likely to take a year or more before the ramp-up in drilling is sufficient to stem the continuing deterioration of supply. Issues of lead time aside, the experience of the past two years teaches strongly that increasing production from conventional sources is likely to be a Herculean task.

To meet the projected needs of the U.S. market, therefore, it will be necessary to undertake a whole new generation of highly capital-intensive, multi-year projects to tap more distant and difficult-to-develop supply sources. The required development efforts include

- construction of the infrastructure required to massively increase imports of liquefied natural gas (LNG) into the U.S. market (including new delivery terminals, new production and liquefaction facilities, and a major expansion of the existing worldwide fleet of LNG tankers);
- construction of the MacKenzie Delta Pipeline to bring natural gas from the Arctic Circle in Canada into the U.S. market;
- maximizing the potential of proven gas reserves at Prudhoe Bay; and
- ultra-deepwater drilling projects in the Gulf.

Few if any of these projects are likely to bear fruit any earlier than the 2008-2010 timeframe. In the interim, the energy industry is likely to experience a prolonged period of sustained higher prices and tight supplies (with periodic steep dips in the spot market price when winter temperatures turn out to be mild).

Promoting a Constructive Response

For some sectors in the industry, higher prices may be welcome news and bring much-needed financial relief. For many load-serving electric utilities and end-use customers, however, the repercussions could be severe. Further, the public outcry is likely to be intense. No matter how unfounded, allegations of price manipulation are likely, accompanied by renewed pressure—however unwise—to reinstitute price caps or some new form of service regulation.

First, we need to be open and honest about the nature and likely duration of the crisis. It is not realistic to expect a quick fix.

Second, while additional development efforts clearly are essential, over the critical period of the next three to five years, energy efficiency will be paramount. This will include upgrades or replacement of existing combustion turbines and steam boilers that still burn natural gas. We also need to improve the availability and output of existing coal-fired units (which remain the primary source of electric generation in the United States). In addition, energy efficiency means working closely with end-use customers, particularly in the commercial sector, where the greatest inefficiencies occur.

Finally, we need to develop a long-term energy strategy that recognizes the limits on our ability to continue to expand supplies of natural gas and the likely long-term costs for new supplies. Over the

past decade, without ever making a careful, well considered decision to do so, the United States has bet much of its future energy strategy (and therefore, potentially its economic health) on the use of natural gas as the near-exclusive source to meet the incremental energy needs of the economy. Clearly, maintaining a balanced mix of fuels for electricity generation is a more sustainable approach.

There is growing evidence, however, that "30 TCF" scenario is simply not achievable. The quicker we reorient our long-term energy strategy, therefore, the better our prospects for renewed economic growth.