Natural Gas: United States Has It if the Price Is Right

Natural gas companies have long contended that freeing natural gas from artificial price controls would lead to substantial increases in the amount of natural gas available in the United States. They have talked in general terms about discovering new occurrences of gas comparable to those already being exploited, and critics have, with some justification, dismissed their arguments as self-serving. The companies' predictions may have been right, however—albeit for the wrong reasons—in view of evidence presented at a recent National Research Council Forum on Potential Resources of Natural Gas. Participants at that meeting suggested that, if gas companies were allowed to sell new gas at prices comparable to those already charged for intrastate deliveries, they might be able to tap already identified sources that would greatly increase our reserves of natural gas. Even with the price increases, moreover, the price of natural gas would still be competitive with the prices of alternative energy supplies.

The panelists considered four types of natural gas resources that are now relatively unexploited. These are gas trapped in coal deposits, gas from shales, gas from the so-called tight sands, and gas from geopressured zones. Each of these types represents a resource that is potentially larger than the current known reserves of natural gas. In each case, the resources can possibly be exploited with modifications of existing technology. The problem is that the cost of obtaining gas from these sources is substantially larger than the price that gas companies are allowed to charge for the gas in interstate commerce.

The United States now has natural gas reserves—resources that can be produced and sold at current prices—of about 8 trillion cubic meters. This reserve is equivalent to about 11 times the current annual rate of consumption. The United States Geological Survey (USGS) last year estimated that the country has no more than an additional 18.5 trillion cubic meters of undiscovered natural gas in conventional deposits. Many experts, however, consider this to be sheer speculation.

Natural gas now sells at various prices. In interstate commerce, it has two prices: 83 cents per 100 cubic meters if it comes from a well drilled before 1973, and $1.80 per 100 cubic meters (51 cents per 1000 cubic feet) if it comes from wells drilled after that date. In comparison, an equivalent amount of energy costs four times as much if purchased as imported oil and as much as 16 times as much if purchased as electricity. Gas sold in intrastate commerce costs $3.50 to $7 per 100 cubic meters—whatever the market will bear. Imported liquefied natural gas will probably cost as much as $7 per 100 cubic meters and synthetic natural gas from coal as much as $14.

Methane from Coal

The new natural gas source that could perhaps be tapped most quickly and cheaply is methane trapped in coal beds. All coal deposits contain methane—the primary constituent of natural gas—adsorbed to the coal. The amount varies from as little as 1 to as much as 20 cubic meters per metric ton of coal, although the average is probably around 7 cubic meters per metric ton. According to Maurice Deul of the U.S. Bureau of Mines' Pittsburgh Mining and Safety Research Center, known coal deposits in the continental United States thus contain a minimum of 8.5 trillion cubic meters of methane. They may contain more.

This methane is a distinct hazard in coal mining. Most mine explosions result from ignition of trapped methane. It is thus necessary for the mine operator to construct expensive ventilation systems to remove methane from the work area, mix it with enough air so that it is not explosive, and vent it to the atmosphere. There are 67 U.S. coal mines each of which vents more than 28,000 cubic meters of methane per day, Deul says, and another 130 that vent more than 2800 cubic meters per day. The total amount wasted, about 2.25 billion cubic meters per year, is small in comparison to the total demand for natural gas. It could, however, make a significant contribution to the energy budget of the Appalachian region, where many of the mines are located.

This gas could be exploited by three primary techniques. The simplest way is to drill a conventional gas well that intersects the coal seam. The Equitable Gas Company of Pittsburgh has been producing natural gas in this manner from the Big Run Field in West Virginia since 1949, according to James G. Tilton of that company. The amount of gas that can be produced in this fashion is quite limited, however, since most coal is not very permeable to methane. One possible solution is to fracture the coal seam to create channels through which gas can flow to the well. But coal miners, Tilton says, object to fracturing for fear that it will damage rock that will eventually form the ceiling of the mine. A second possibility is to drill a large shaft to the coal seam, then drill horizontal holes through the coal seam to provide channels for gas flow.

The best alternative, Deul says, is to dig the main mine shaft several years before the mine is to be opened. Horizontal holes could then be drilled through the coal from this shaft. To test the possibility, the Bureau of Mines drilled seven such holes in an existing shaft at an Eastern Associated Coal Corporation mine in West Virginia. After 1192 days of operation, Deul says, the shaft has produced 21 million cubic meters of gas, much of which has been conducted into a nearby pipeline. Five similar holes drilled in an adjacent ventilation shaft have yielded an additional 20 million cubic meters. Gas is still being produced at nearly the original rate, and Deul predicts that a total of 142 million cubic meters will be obtained at this one site before the coal is mined.

Even at current gas prices, Deul says, the sale of the gas would pay the cost of digging the shaft before a site is opened for coal mining. The mine operators would receive additional benefits in that they would not have to construct as large a ventilation system for the mine, and productivity would be increased (mine operators currently lose about 40 minutes per shift when methane levels rise above safe concentrations). If the price of gas rises, Deul concludes, many independent entrepreneurs will begin producing gas in this manner.

A second major source of natural gas is the Devonian shale that underlies more than 650,000 square kilometers of the eastern and midwestern United States. This shale, which is more similar to coal than to western oil shale, contains about 0.63 to 0.95 cubic meters of trapped natural gas per metric ton. The USGS estimates that there are about 14 trillion cubic meters of gas in Devonian shale.

Gas has been produced from shale for many years, but only on a limited, regional basis. Approximately 4616 wells in the Big Sandy Field in eastern Kentucky, for example, produce gas from Devonian shale, according to Edward R. Ray of the Kentucky West Virginia Gas Company, Ashland, Kentucky. These wells have so far produced a total of about 482 billion cubic meters from producible reserves estimated at about 565 billion cubic meters. Most of these wells were discovered during the search for conventional natural gas deposits, notes John Avila of Ashland Exploration Company, since it is currently too expensive to explore only for shale deposits.

Most Devonian shale wells, says Porter J. Brown of the Columbia Gas Transmission Corporation, Charleston, West Virginia, are producing only gas that is contained in natural fractures, even though gas flow has routinely been stimulated by detonating explosives within the well. Beginning in 1965, Kentucky West Virginia Gas Company has been experimenting with stimulation by hydraulic fracturing. In this technique, water containing various additives is injected into the well under high pressure to fracture the shale and create channels through which gas can flow to the well. Sand is injected with the water to prop open the channels created by the fracturing. In most of the company's wells, Ray says, about 1000 barrels (1 barrel = 160 liters) of water and 23,000 kilograms of sand are injected.

Fracturing, Ray says, increases the initial flow of gas from the wells by about 50 percent. This is the same order of magnitude as the increase achieved with explosives. But the flow rate is maintained for a longer period of time in fractured wells. This reduces the time required for recovery of the well's reserves by as much as 50 percent in wells with the slowest flow. Fractured wells may produce for as long as 25 years.

Columbia Gas is planning a large-scale effort to exploit gas from Devonian shale in the Appalachian region, according to William Morse of that company. But to do so, he contends, the company will need "lenient" rate treatment from the Federal Power Commission so it can pass on its costs to its customers. This would probably mean a wellhead price for shale gas as high as $7 per 100 cubic meters. He estimates, furthermore, that his company and others will have to spend $100 million on refinement exploration, drilling, and fracturing techniques in order to tap the shale gas.

The third potential source is gas in tight sands. Here, the gas is found in layers of clay, chalk, and sandstone that are interspersed with the shale. These materials have a very low permeability to natural gas, and therefore the only way it can be collected is by massive fracturing of the gas-bearing tight-sand strata. It is thus more difficult and expensive to drill wells and stimulate gas flow, but much more gas is obtained per well. The total resources are also larger. The USGS estimates that there are about 17 trillion cubic meters of gas trapped in the Fort Union and Mesaverde reservoirs in the Rocky Mountains and an equivalent amount at other sites.

Attempts to free this gas have been based on two techniques: fracturing with nuclear explosions and massive hydraulic fracturing. By far the most controversial of these is nuclear fracturing, which so far has been attempted only three times. The first two attempts, Gasbuggy in 1967 and Rulison in 1969, each involved detonation of a single nuclear device. In the third attempt, Rio Blanco, three devices were exploded simultaneously in an effort to stimulate a 400-meter section of tight sands in the Piceance basin of western Colorado. The fracture cavities produced by the three explosions did not become interconnected, however, and gas production has been only one-tenth to one-sixth as high as had been predicted, according to Gerald R. Luetkehans of CER Geonuclear, Las Vegas. Even so, he points out, production of gas by this technique would be economic if the price of gas rose somewhat. But it seems probable that a combination of environmental and political pressures will prevent any significant use of this technique.

Fracturing Tight Sands

Massive hydraulic fracturing is similar to the hydraulic fracturing used in Devonian shales, but the amount of sand and water pumped into the wells is much larger. In one well experimentally fractured by the El Paso Natural Gas Company of El Paso, Texas, for example, nearly 1.9 million liters of water and 620,000 kilograms of sand were injected into the well. A more typical well, however, probably requires only about half those quantities.

Mixed results have been obtained with massive hydraulic fracturing. Experiments conducted by El Paso, by Amoco Production Company of Tulsa, Oklahoma, and by CER Geonuclear (for a consortium of 15 energy companies) have been characterized by a much smaller stimulation of gas flow than had been predicted. These results suggest that knowledge of the exact location of the gas deposits is imprecise. But a series of ten fracturing experiments conducted in western Wyoming by Pacific Transmission Supply Company has produced commercial quantities of gas at flow rates near those predicted.

Many companies are attempting massive hydraulic fracturing in the Rocky Mountain basins in efforts both to learn and to refine the technique. And a few companies, according to Myron Dorfman of the University of Texas, are using the technique to produce gas from tight sands in the Gulf Coast basins, where the gas can be sold intrastate at a price high enough to recoup costs. A price increase in interstate gas would provoke an immediate increase in production from tight sands, according to Lloyd E. Elkins of Amoco. If the price rose to $7, he says, the Rocky Mountain basins could be producing at least 28 billion cubic meters per year in 6 or 7 years.

The most speculative, but perhaps also the largest, potential source of natural gas is the geopressured zone of the Gulf Coast. This zone, which covers all of Louisiana and much of the adjacent states, consists of large aquifers at depths of 2500 to 8000 meters. These aquifers are characterized by high temperatures (above 150°C) and pressures that are as much as twice those of conventional water at comparable depths. At such temperatures and pressures, says Paul H. Jones of Louisiana State University, nearly all organic matter is eventually converted to methane. This methane dissolves in the aquifers at concentrations as high as 1.28 cubic meters per barrel of water. Estimates of the total amount of methane in onshore aquifers vary widely. Bill R. Hise of Louisiana State University estimates they contain 85 trillion cubic meters. The USGS estimates 680 trillion cubic meters. And Jones estimates a staggering 1400 trillion cubic meters. The magnitude of the variation suggests how little is actually known about the aquifers. Similar quantities of gas probably exist in offshore aquifers.

Exploiting the gas will not be simple. For wells to be commercially viable, they will have to produce as much as 100,000 barrels of water per day. This type of flow rate has never been attempted before. And even at that flow rate, production of 28.3 billion cubic meters of gas per year would require 1000 wells—at a cost of as much as $3 million apiece. Disposal of the water could be a major environmental problem, particularly if it contains appreciable quantities of dissolved solids. Subsidence of the land over the aquifers could also be a severe problem. Offsetting these problems somewhat, however, is the energy content of the hot water, which could possibly be used for production of electricity.

Because of subsidence, it will probably be possible to remove only about 5 percent of the water from the aquifers. This would produce at least 3.54 trillion cubic meters of gas, even at the most conservative estimates. The crucial question is what will happen in the aquifer then. Jones suggests that pumping out 5 percent of the water will lower the aquifer pressure enough so that the gas will exsolve from the water and collect in "artificial" gas caps that can be tapped by conventional techniques. It would thus be possible to obtain most of the gas. Hise argues, however, that the exsolved gas would remain dispersed throughout the aquifer.

The USGS has developed a plan, supervised by Dorfman, to explore the feasibility of obtaining gas from geopressured zones. There are many problems involved in exploiting this gas, Dorfman says, but it must be remembered that the difficulties are minimal in comparison to those associated with other technologies, such as nuclear energy.—THOMAS H. MAUGH II