What to do when you have gas

Here's an analysis of the economic and environmental benefits to be gained from not simply flaring natural gas

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No, this article has nothing to do with antacid. Rather, it examines the possible alternate value-added scenarios for the optimum use of natural gas resources in some major applications.

Basis for evaluation. This value-added analysis is based on the yearly economic cost for operating the gas-consuming facility. The amortization of capital is based on a simple payout period of five years on the total installed cost for the facility. Operating costs are based on estimated costs for labor, maintenance, chemicals and lubricants, cooling water, power, rights of way, property taxes and insurance.

In cases where a certain portion of the gas is consumed in the process (for example, compressing gas for a pipeline or an LNG facility using a gas turbine), the gas consumed was valued at 50 cents/MMBtu (HHV) at the production well. This value is low in developed economies. However, in remote developing economies, this nominal value is appropriate.

Venting or flaring. Other than venting, flaring is the least productive use of natural gas. There is no economic value addition by flaring gas. This unit operation is performed for safety reasons and as a method of dealing with effluent. Another reason gases are flared rather than simply vented is to lower greenhouse gas emissions. It is estimated that worldwide 5 trillion cubic feet/year of natural gas are vented or flared each year.[1] This equals approximately one-quarter of total demand for natural gas in the US.

On a pound-for-pound basis, methane has 21 times the greenhouse effect of carbon dioxide. Therefore, as combustion produces only 2.75 lb of carbon dioxide for each pound of methane flared, flaring is 7.6 times more preferable than venting from a greenhouse point of view. Of course, every effort should be made to capture and use the natural gas as opposed to venting or flaring.

As countries that extract oil with associated gas begin to develop their economies, the gas can find markets. Russia, Nigeria, Algeria and Iran are some examples where venting and flaring have been reduced substantially. The capital cost of a flare system to burn 100 million standard cubic feet per day (MMscfd) of natural gas is approximately $200,000.[2] There are essentially no operating costs for the system.

Therefore, if capital is recovered on a simple payout basis in five years, the yearly costs associated with running a flare system and the "value added" compared with simply venting the gas is $40,000/yr for a facility with a base capacity of 100 MMscfd. This equals approximately 0.1 cents per MMBtu.

Compression and reinjection. The next lowest form of value added is to capture the gas, compress it to an elevated pressure and reinject the gas back into the reservoir to maintain reservoir pressure and, in turn, production capacity. The capital cost for collection and reinjection at the rate of 100 MMscfd is of the order of magnitude of $5 million.[3] For this economic evaluation, the cost of natural gas at the wellhead to power the compression turbines is arbitrarily set at 50 cents per Mscf.

Approximately 3% of the natural gas is consumed in the compression system. Therefore, 3 MMscfd of natural gas equals $1,500/day or approximately $550,000/yr. Other operating costs for the reinjection system are labor, maintenance, chemicals and lubricants, property taxes and insurance. These are estimated at $450,000/yr. Capital recovery over five years equals $1 million/yr. Therefore the total value added for the reinjection system is $2 million/yr or about 5.5 cents/MMBtu. Adding the 50 cents/MMBtu for the gas at the wellhead, the value of gas reinjected into the production field is 55.5 cents/MMBtu.

Compression and sale by pipeline. The capital cost for compression and a 50-mi pipeline to transport 100 MMscfd is of the order of magnitude of $40 million.[4] For this economic evaluation, the cost of natural gas at the wellhead to fire the compression turbines is arbitrarily set at 50 cents/Mscf. Approximately 3% of the natural gas is consumed in the compression system. Therefore, this equals 3 MMscfd of natural gas or $1,500/day or approximately $550,000/yr.

Other operating costs for the compression and pipeline sys-

Many applications

Natural gas or methane is a widely distributed fuel and can be used for a variety of economic purposes. These include, but are not limited to: generating electricity in simple-cycle and combined-cycle stations; raising steam in boilers; producing ammonia and ethylene; manufacturing hydrogen and carbon monoxide; producing synthesis gas for diesel and for methanol; compressing the gas into tanks as a transportation fuel; liquefying the gas for transport and sale in a distant market; compressing the gas into a pipeline for sale elsewhere; or, if all else fails, flaring or venting gas that has no immediate use.

tem are labor, maintenance, chemicals and lubricants, rights of way, property taxes and insurance. These are estimated at $1.1 million/yr. Capital recovery over five years equals $8 million/yr. Therefore, the total value added for the compression and pipeline system is $9.1 million/yr or about 25 cents/MMBtu, without any value for the gas. Adding the 50 cents/MMBtu for the gas at the wellhead, the value of gas delivered to the end of the pipeline 50 mi away is 75 cents/MMBtu.

Liquefaction. Capital cost for a liquefaction plant to process 100 MMscfd is of the order of magnitude of $400 million.[5] For this economic evaluation, the cost of natural gas at the wellhead to fire the compression turbines is arbitrarily set at 50 cents/Mscf. Approximately 9% of the natural gas is consumed in the compression system. Therefore, this equates to 9 MMscfd of natural gas or $4,500/day or approximately $1.65 million/yr.

Other operating costs for the liquefaction plant are labor, maintenance, chemicals and lubricants, rights of way, property taxes and insurance. These are estimated at $20 million/yr. Capital recovery over five years equals $80 million/yr. Therefore, the total value added for the liquefaction plant is $100 million/yr or about 275 cents/MMBtu, with no value placed on the natural gas that is liquefied. Adding the 50 cents/MMBtu for the gas, the total value is 325 cents/MMBtu. Note that this is FOB the liquefaction plant and does not include transportation to the destination.

Simple-cycle power generation. The 100 MMscfd of natural gas can power a 390-MW power plant at a heat rate of 10,000 Btu/kWh.[6] The power plant with substation costs about $485,000/MW or a total cost of $189 million.[7] The cost of the natural gas at 50 cents/MMBtu is $5,000/day or approximately $18.25 million/yr.

Other operating costs for the simple-cycle power generation station are labor, maintenance, chemicals and lubricants, cooling water, property taxes and insurance. These are estimated at $8 million/yr. Capital recovery over five years equals $37.8 million/yr. Therefore, the total value added for the simple-cycle power generation station is $64.25 million/yr or about 176 cents/MMBtu, including the gas at 50 cents/MMBtu. Excluding the value of the gas, the value added is 126 cents/MMBtu. Note that this value is FOB the substation at the simple-cycle power generation station and does not include power transmission and distribution to the point of use.

Combined-cycle power generation. The 100 MMscfd of natural gas can power a 550-MW power plant at a heat rate of 7,000 Btu/kWh.[8] The power plant with substation costs about $654,000/MW or a total cost of $360 million.[9] The cost of the natural gas at 50 cents/MMBtu is $5,000/day or approximately $18.25 million/yr.

Other operating costs for the simple-cycle power generation station are labor, maintenance, chemicals and lubricants, cooling water, property taxes and insurance. These are estimated at $14 million/yr. Capital recovery over five years equals $72 million/yr. Therefore, the total value added for the combined-cycle power generation station is $106.25 million/yr or about 291 cents/MMBtu, including the value of gas at 50 cents/MMBtu. The value added without any value placed on the gas is 241 cents/MMBtu. Note that this value is FOB the substation at the combined-cycle power generation station and does not include power transmission and distribution to the point of use.

Hydrogen manufacture. The 100 MMscfd of natural gas can produce 254 MMscfd of hydrogen.[10] The steam methane reformer, shift conversion and pressure swing adsorption purification system that comprise the hydrogen plant cost $150 million.[11] The cost of the natural gas at 50 cents/MMBtu is $50,000/day or approximately $18.25 million/yr.

Other operating costs for the hydrogen plant are labor, maintenance, catalysts chemicals and lubricants, water, property taxes and insurance. These are estimated at $11 million/yr. Capital recovery over five years equals $30 million/yr. Therefore, the total value added for the hydrogen plant is $59.25 million/yr or about 162 cents/MMBtu, including the value of gas at 50 cents/MMBtu. The value added without any value placed on the gas is 112 cents/MMBtu. Note that this is FOB the hydrogen production plant and does not include hydrogen compression and storage.

Methanol production. The 100 MMscfd of natural gas can produce 240 million gal/yr of methanol and 63.5 MMscfd of hydrogen.[12] The steam methane reformer, methanol synthesis and pressure swing adsorption purification system that comprise the plant cost $250 million.[13] The cost of the natural gas at 50 cents/MMBtu is $50,000/day or approximately $18.25 million/yr.

Other operating costs for the plant are labor, maintenance, catalysts chemicals and lubricants, water, property taxes and insurance. These are estimated at $20 million/yr. Capital recovery over five years equals $50 million/yr. Therefore, total value added for the methanol synthesis plant is $88.25 million/yr or about 242 cents/MMBtu, including the value of gas at 50 cents/MMBtu. The value added without any value placed on the gas is 192 cents/MMBtu. Note that this is FOB the hydrogen and methanol production plant and does not include hydrogen compression and storage or methanol transportation.

Direct reduced iron concentrate. The 100 MMscfd/day can be used to produce 3.5 MMton/yr direct reduced iron (DRI)[14] as is done in several locations presently. This DRI facility will cost approximately $400 million.[15] Unfortunately, DRI is not a fully tradable commodity and is a poor substitute for scrap steel.

There is a technology to upgrade DRI further to direct reduced concentrate (DRC)[16] that is an excellent substitute for scrap steel. The additional investment to convert 3.5 MMton/yr of DRI into 3.3 MMton/yr DRC is approximately $50 million,[17] making the total investment $450 million. The cost of the natural gas at 50 cents/MMBtu is $50,000/day or approximately $18.25 million/yr. Iron ore at $51.40/ton would cost $274 million/yr.[18] Power costs are estimated at $6.3 million/yr.

Other operating costs for the plant are labor, maintenance, catalysts chemicals and lubricants, water, property taxes and insurance. These are estimated at $40 million/yr. Capital recovery over five years equals $90 million/yr. Therefore, total value added for the manufacture of DRC steel scrap substitute is $410.3/yr or about 1,172 cents/MMBtu, including the value of gas at 50 cents/MMBtu. The value added without any value placed on the gas is 1,122 cents/MMBtu. Note that this is FOB the DRC scrap steel substitute facility and does not include DRC transportation.

Overview. Tables 1–3 summarize the value-added findings of this article. Excluding venting or flaring, in developing countries with natural gas resources, the least capital-intensive method to add value is to reinject the gas. The next least capital-intensive

TABLE 1. Capital required to treat 100 MMscfd of natural gas by various processes

Process	Total capital cost for process
Venting	$200,000
Flaring	$200,000
Reinjection	$5 million
Pipeline	$40 million
Liquefaction	$400 million
Simple-cycle power	$189 million
Combined-cycle power	$360 million
Hydrogen production	$150 million
Methanol production	$250 million
DRC (steel scrap substitute)	$450 million

TABLE 2. Value added in cents/ MMBtu (not including gas value)

Process	Value added
Venting	0.1
Flaring	0.1
Reinjection	5.3
Pipeline	25
Liquefaction	275
Simple-cycle power	126
Combined-cycle power	241
Hydrogen production	112
Methanol production	192
DRC (scrap steel substitute)	1,122

TABLE 3. Value added in cents/ MMBtu (with gas value of 50 cents/ MMBtu)

Process	Value added
Venting	0.1
Flaring	0.1
Reinjection	55.3
Pipeline	75
Liquefaction	325
Simple-cycle power	176
Combined-cycle power	291
Hydrogen production	162
Methanol production	242
DRC (scrap steel substitute)	1,172

method to add value in these developing economies blessed with natural gas resources is to pipeline the gas to cities and towns where there is residential, commercial or industrial use for the gas.

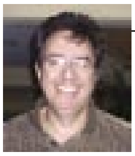
The third least capital-intensive enterprise is to produce electric power using simple-cycle gas turbines. Hydrogen production is meaningless unless coupled with methanol, diesel, or fertilizer synthesis. DRC iron (scrap steel substitute) is the technology with by far the highest value addition. This technology is capital intensive, requires iron ore and may be applicable only in certain situations.

Combined-cycle power production or LNG are the two other most capital-intensive technologies. While these two technologies increase the economic value added over the other technologies that were analyzed, excepting DRC steel scrap substitute, their high capital requirements may imply that only major multinational corporations are capable of financing and developing such projects in lesser developed countries.

All efforts should be made to reinject or pipeline natural gas that is presently flared as this will have both environmental and economic benefit without a high level of capital intensity. **HP**

REFERENCES

[1] US DOE Energy Information Administration, International Energy Outlook, April 2004.
[2] Rough order of magnitude estimate for a simple flaring system capable of burning 100 MMscfd of gas.
[3] Rough order of magnitude estimate for a simple compression system to reinject 100 MMscfd of gas into a production well.
[4] Rough order of magnitude cost of a 50-mi pipeline, including compression system to deliver 100 MMscfd of gas.
[5] Based on scaling down the cost of a 4-million-ton/day LNG facility.
[6] Based on a heat rate of 10,000 Btu/kWh LHV for a simple-cycle gas turbine.
[7] Based on a total installed cost of $485/kW for a simple-cycle power generation station.
[8] Based on a heat rate of 7,000 Btu/kWh LHV for a combined-cycle gas turbine.
[9] Based on a total installed cost of $654/kW for a combined-cycle power generation station.
[10] Based on a steam methane reformer with shift conversion having an overall thermal efficiency of 75%.
[11] Based on a rough order of magnitude estimate for a two-train steam methane reformer with shift conversion and pressure swing adsorption purification facility with a capacity of 254 MMscfd of hydrogen.
[12] Based on a steam methane reformer without shift conversion having an overall thermal efficiency of 75% and subsequent methanol synthesis with a thermal efficiency of 75%. Excess hydrogen is also marketed and sold.
[13] Based on a rough order of magnitude estimate for a two-train steam methane reformer and single-train methanol synthesis.
[14] Based on a heat rate of 10 MMBtu/ton of DRI.
[15] Based on a rough order of magnitude estimate for a two-train Midrex DRI system.
[16] Patents held by DRC Technology.
[17] Based on a rough order of magnitude estimate for a two-train DRC system.
[18] Iron ore with 60% Fe content, DRC with 97% Fe content.



Lindsay Leveen began working in industry at Air Products and Chemicals where he was involved in designing, constructing and operating industrial gas producing facilities in the areas of liquefied natural gas, hydrogen, carbon monoxide, oxygen and nitrogen. After six years, he joined L'Air Liquide, and was responsible for developing large onsite supply systems for industrial gas plants. He later became vice president of planning in the Paris, France, headquarters. Mr. Leveen has consulted to major corporations in areas of energy deregulation, fuel cells, telecommunication, alternate fuels, thin film deposition, power generation, transmission and distribution, as well as a variety of other process-based technologies. He received a BS in chemical engineering and an MBA from the University of the Witwatersrand, Johannesburg, South Africa. He also has an MS degree in chemical engineering from Iowa State University of Science and Technology.