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North American Natural Gas Markets

Energy Modeling Forum

Stanford University

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Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy problems. The ninth EMF study, *North American Natural Gas Markets*, was conducted by a working group comprised of leading natural gas analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 9 working group met five times from October 1986 through June 1988 to discuss key issues and analyze natural gas markets.

This report summarizes the results of the working group study. It is based upon the full working group report and other technical papers prepared during the study. Inquiries about the availability of these other reports should be directed to the Energy Modeling Forum, 406 Terman Center, Stanford University, Stanford, CA 94305 (Telephone: 415-723-0645).

Funding for this study was generously provided by the U.S. Department of Energy, the Electric Power Research Institute, and member organizations of the EMF Affiliates Program. Affiliate organizations include: Alberta Department of Energy, ARCO, Bonneville Power Administration, Conoco, Consolidated Edison, Gas Research Institute, General Motors, Interstate Natural Gas Association of America, Maxus, Pacific Gas and Electric, Shell U.S.A., Southern California Edison, and Union Pacific Resources. Additional support for this study from Amoco, California Energy Commission, Southern California Gas, and Benjamin Schlesinger and Associates is also gratefully acknowledged.

EMF's Senior Advisory Panel continues to offer valuable advice on topics as well as comments and suggestions for improving EMF reports. And finally, we would also like to acknowledge Edith Leni, Pamela McCroskey, Douglas Robinson, Dorothy Sheffield, and Susan Sweeney for their assistance in the production of this report.

This volume reports the findings of the EMF working group. It does not necessarily represent the views of Stanford University, members of the Senior Advisory Panel, or any organizations providing financial support.

Contents

List of Figures

List of Tables

Senior Advisory Panel†

The Energy Modeling Forum (EMF) seeks to improve the usefulness of energy models by conducting tests of models in the study of key energy issues. The success of the Forum depends upon the selection of important study topics, the broad involvement of policymakers, and the persistent attention to the goal of improved communication. The EMF is assisted in these matters by a Senior Advisory Panel that recommends topics for investigations, critiques the studies, guides the operations of the project and helps communicate the results of the energy policymaking community. The Panel is not responsible for the results of the individual EMF working group studies.

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Executive Summary

This report summarizes the research by an Energy Modeling Forum working group on the evolution of the North American natural gas markets between now and 2010. The group's findings are based partly on the results of a set of economic models of the natural gas industry that were run for four scenarios representing significantly different conditions: two oil price scenarios (upper and lower), a smaller total U.S. resource base (low U.S. resource case), and increased potential gas demand for electric generation (high U.S. demand case). Several issues, such as the direction of regulatory policy and the size of the gas resource base, were analyzed separately without the use of models.

Pricing

- By 1990, gas prices in the United States and Canada begin to reverse their decline of the 1980s in the scenarios analyzed, reflecting the elimination of the current excess deliverability condition.

- After 1990, gas prices in the United States and Canada rise continuously, reflecting higher oil prices and smaller field size and higher exploration and development costs of future reserve additions. By 2000, inflation-adjusted gas prices reach their peaks of the early 1980s, even in the lower oil price case.

- In the long run, burnertip natural gas and residual fuel oil prices need not necessarily equate on a per Btu (i.e., heat content) basis. Depending upon the model, gas prices are at or below parity with residual fuel oil in the upper oil price case; are generally at parity in the high demand case; and are at or above parity in the low resource and lower oil price cases.

- There currently exists considerable capability for switching between natural gas and residual oil in equipment that can burn either fuel (the dual-fuel market). When gas supplies are plentiful enough to saturate this dual-fuel market, gas prices may fall below the price of residual fuel oil; conversely, when supplies are limited enough to cause this dual-fuel market to be lost, the gas price will rise above the residual fuel oil price. As long as a large amount of gas continues to be used by these dual-fired industrial and powerplant customers, gas prices will tend to be capped by residual fuel oil prices.

Supply

- Resource base estimates are highly uncertain. The cost of proving and producing resources is as important as the extent of resources in place for determining gas supply and price. Despite standardizing on oil price and the physical magnitude of the resource base, substantial variations in incremental resource costs exist among the models.

- Poorly drained reservoirs or uncontacted compartments in existing reservoirs may contain significant gas reserves that can be produced through infill drilling and recompletions. This phenomenon, reserve growth, represents a potentially significant source of additional gas, although confirmation of preliminary estimates is needed.

- Changes in oil prices, undiscovered resources, and gas demands can lead to a wide variation in production across the four scenarios—from 14 to 18 Tcf by 2000 and from 12 to 19 Tcf by 2010 (according to the average of all model results).
- Total U.S. gas imports rise substantially in all scenarios, reaching 1.5 Tcf by 2010 in the lower oil price case and 2 Tcf or more in the other scenarios compared to 1 Tcf in 1987. Although Canada remains the principal source of U.S. imports, liquefied natural gas (LNG) and, in some instances, Mexican gas, also contribute to U.S. imports.
- To sustain annual Canadian gas export levels at 2 Tcf in the upper oil price case, Canadian frontier and unconventional supplies need to be developed in a timely manner for delivery after the turn of the century. In this study, Canadian gas exports are generally less in the Canadian and North American models than in the U.S. models in all scenarios.

Consumption (Demand)

- Variations in the projections of industrial demand are quite large by 2010, ranging from a total of 4 Tcf to approximately 8 Tcf in different models in the upper oil price scenario, constituting 22 to 41 percent of total demand. Much of this variation stems from fuel-switching and different assumptions about the penetration of new industrial gas-fired technologies. The range in the demand by electric utilities is also large—from 2.9 to 5.7 Tcf by 2010—depending upon assumptions about environmental regulations, fuel prices, and load growth.
- In the lower oil price and low resource cases, gas consumption declines relative to the upper oil price case as industrial and electric utility users switch to oil, primarily in dual-fired boilers. Since U.S. oil production is expected to decline in the future, some of the lost gas consumption will be met by rising oil imports. The average gas consumption decline across all models was 2.9 Tcf in 2010 in the lower oil price case and 3.5 Tcf in the low U.S. resource case, or in oil-equivalent terms, 1.4 million barrels per day (MMBD) and 1.7 MMBD, respectively.
- Satisfying the higher electric utility gas demands of the high U.S. demand case requires higher gas prices than in the upper oil price case. The higher gas price brings forth additional gas supplies, primarily domestic, by encouraging exploration and development, and reduces consumption in other gas demand sectors. While potential gas demand is increased by 2.8 Tcf, actual total gas consumption rises by only 1.5 to 2.0 Tcf by 2010 as a result of the higher gas price.

Regulatory Policy

- The U.S. gas industry has been highly regulated and regulatory decisions have often interfered with market forces. With increased competition, the focus of regulation is changing from price and volume controls to the conditions of access to and participation in the gas market. In the future, regulators—state, provincial, and federal in the U.S. and Canada—will continue to have a major impact on the gas market.
- The distribution of gains and risks among producers, pipelines, local distribution companies (LDCs), and end-users will be an important element in many regulatory issues, such as rate design, the allocation of pipeline capacity, and bypass of LDCs by their customers. Nevertheless, market forces will constrain the ability of regulators to reallocate economic benefits and risks among market participants.

- A streamlined approval process for the construction of new interstate pipeline facilities into new markets will be important to improve the allocation of resources.

- Under some scenarios—especially a lower resource base—regulators may face political pressures to overturn, or not adopt, some pro-competitive policies. To the extent industry participants anticipate that pro-competitive policies will be reversed by regulators, some participants may respond to this uncertainty by reducing investment.

Natural Gas Modeling

- Several methodologies exist to model natural gas markets. Methodology, however, accounts for only a portion of the variation among model results. Different perspectives about fundamental gas supply, demand, and pricing relationships are also important explanations for variations between model results.

- The models used in this study were originally developed to project long-term trends in gas prices, production, and consumption. They have been useful for understanding some key long-run relationships and developing insights about the industry's development. Most models, however, did not directly incorporate regulatory behavior in their structures, nor did they allow transmission and distribution margins to be determined by gas market forces.

- As the gas market develops, it will be important to better reflect within the model frameworks the increasing integration of the U.S. and Canadian gas markets, interregional competition within each country, impacts of regulatory policy, technological changes in gas supply and demand, alternative natural gas resource base estimates, the setting of transmission and distribution margins, price volatility, environmental regulations, and short-run dynamics. Developing better analyses of these factors will improve decisionmaking and represents an important challenge.

North American Natural Gas Markets

A dozen years ago, the United States was in the throes of a severe natural gas shortage. Moratoria on new customers were instituted and large existing customers had their gas service curtailed. Prices were set under long-term contracts, which were subject to regulation from the field to the *burnertip*.[1] In this environment, frequent reference was made to natural gas being a "premium" fuel that in an unregulated market could attract a price above that of distillate fuel oil, reflecting its cleaner-burning properties.

Gas market conditions are dramatically different today. The gas-producing industry has been mired in excess deliverability for several years. Both U.S. and Canadian producers are aggressively searching for new markets for their surplus gas, while consumers are enjoying the benefits of lower prices. Many long-term contracts with fixed prices have been renegotiated to incorporate market-responsive pricing and many have been replaced by shorter-term contracts and *spot market* sales. More than half of today's annual gas sales are spot-market transactions. The regulatory policy debate has shifted from an emphasis on the security of supply to the deregulation of field prices and then to the issues of access to and the allocation of pipeline capacity. Gas prices are being set by *"gas-to-gas" competition*, which has lead to burnertip gas prices falling below *residual fuel oil* prices.

This shift in market conditions from one constrained by regulations to one relying more upon market forces emphasizes the uncertainty about this industry's future evolution. What will this market look like through the 1990s and beyond? Will excess deliverability continue? Will the pricing of natural gas revolve around the switchable end-use market comprised of large industrial and electric utility users with dual fuel-burning capacity? Or will natural gas and residual fuel oil prices diverge under certain conditions? How will the regulatory environment resolve such issues as "open access" to the nation's gas transmission system?

In short, growing competition in the North American natural gas market has increased the uncertainty about the industry's development. In addition, industry experts hold divergent opinions on such critical issues as resource availability, end-use demands, the proper regulatory climate, and pricing.

The *Energy Modeling Forum* working group (EMF 9) analyzed the development of the North American natural gas industry under different conditions with respect to oil prices, the natural gas *resource base*, and gas demand. In addition, regulatory policy issues were addressed. This group comprised leading natural gas analysts, listed at the beginning of this report, from government, industry, universities, and research and consulting organizations. In conducting the analyses, the group pursued two broad goals. First, it sought to develop insights about the gas market's development under a range of different environments by using economic models and additional analyses. Second, it sought to evaluate the existing analytical approaches available for understanding this industry and discuss their strengths and limitations.

The models of the natural gas industry guided the group's thinking about many important market relationships and helped identify important differences of opinion about future outcomes. While

[1]Italics indicate the first use of words or phrases listed and defined in the Appendix.

many of the conclusions depend on the model results, several issues, such as regulatory policy and the size of the resource base, could not be analyzed using the models. These latter issues were studied separately by group members to determine how they might affect the industry's evolution.

Scenarios

Models are often used to develop projections about the "most likely" market conditions. The working group, however, did not define such a case in this study. Given the uncertainty about the future development of the North American natural gas market, the group found it more valuable to develop insights about key gas market relationships under very different environments. In this study, the working group evaluated four standardized scenarios that included the effects of different gas resource bases, oil price paths, and potential sources of gas demand on the natural gas market.

The key scenario inputs are listed in Table 1. The two oil price scenarios are extensions of price paths analyzed in a National Petroleum Council (NPC) study.[2] In the upper oil price scenario, the oil price rises from $15 per barrel in 1986 to $36 in 2000 and $44 in 2010 (1986 dollars). In the lower oil price scenario, it rises to $21 in 2000 and $26 in 2010. The two oil price scenarios incorporate a lower-48 natural gas resource base of 933 trillion cubic feet of undiscovered and inferred resources plus proved reserves.[3] Using the upper oil price assumptions, the group also investigated two other scenarios. In one scenario, the effects of a lower U.S. resource base of 591 trillion cubic feet of undiscovered resources plus proved reserves (low U.S. resource case) were examined.[4] Another scenario assumes a higher level of potential gas demand for electric generation resulting from an acid rain policy and from increased penetration of *combined-cycle gas turbine* technologies (high U.S. demand case). In all four scenarios, Canadian gas exports to the United States are capped at 2 trillion cubic feet per year, reflecting the working group's assessment of the maximum economically sustainable export levels between the two countries.

Eleven models of the U.S. and Canadian gas markets were run for each scenario by standardizing on the key inputs contained in Table 1. In some cases, e.g., the resource base, the EMF inputs differed substantially from those often used by the proprietors of a model.

The EMF 9 working group also surveyed a group of oil companies and other organizations to determine their natural gas supply and demand outlooks for comparison to the model results. A similar survey was conducted by the National Petroleum Council in 1986. The results from the EMF 9 survey were in close agreement with the NPC survey results.

Major Findings and Issues

Based upon discussions and analysis, the group reached conclusions on gas pricing, consumption, supply, regulatory policy, and the use of models. Table 2 contains averages of the model results for selected variables for the 1985- 2010 period across the four scenarios.

Natural Gas Pricing

Surplus deliverability—the *gas bubble*—has existed in the U.S. gas industry since the beginning of the 1980s and has contributed to declining gas prices in recent years. The model results show this price trend reversing by 1990 in all scenarios (Figure 1), suggesting that the period of excess deliverability is nearing an end.

Once the current excess deliverability of natural gas is eliminated and gas supply and demand are

[2] National Petroleum Council, *Factors Affecting U.S. Oil and Gas Outlook*, Washington, D.C., 1987.

[3] For comparison, a recent DOE lower-48 estimate is 1059 trillion cubic feet. See U.S. Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States*, Washington, D.C., May 1988.

[4] For comparison, a preliminary 1988 Department of Interior estimate is 517 trillion cubic feet.

Table 1: **Key Scenario Inputs for EMF 9**

Key Assumptions	Upper Oil Price	Lower Oil Price	Low U.S. Resource	High U.S. Demand
World crude oil price (1986$/barrel)				
1986	$15	$15	$15	$15
1990	$22	$14	$22	$22
2000	$36	$21	$36	$36
2010	$44	$26	$44	$44
US economic growth rate, 1985-2000 (% p.a.)	2.6%	2.7%	2.6%	2.6%
US Lower-48 inferred and undiscovered resources (Tcf)				
Conventional	627[a]	627[a]	388[b]	627[a]
Unconventional at $5/Mcf	97	97	0	97
Infill Drilling at $5/Mcf	50	50	44	50
TOTAL	774	774	432	774
Proven Reserves Lower-48 (Tcf, 1986)[c]	159	159	159	159
Total Undiscovered Plus Proven	933	933	591	933
Canadian Export Cap (Tcf/yr)	2	2	2	2
Extra potential U.S. utility gas demand (Bcf/yr)				
1990	0	0	0	296
2000	0	0	0	1431
2010	0	0	0	2807

Tcf—Trillion cubic feet.
Bcf—Billion cubic feet.
Mcf—Thousand cubic feet.

[a]1986 Potential Gas Committee (PGC) Most Likely Estimate, plus 7 Tcf for offshore gas deeper than 1000 meters. Estimate is not based upon any explicit price assumptions.

[b]Based upon 1986 PGC Low Estimate, which assumes "that there is approximately a 90 percent or greater probability that at least this much natural gas resources is present." Also includes 4 Tcf of offshore gas in water deeper than 1000 meters. Estimate is not based upon any explicit price assumptions. See "EMF 9 Study Design" in Volume 3.

[c]Discovered gas that is excluded from estimates of undiscovered resources.

Table 2: **Average of Model Results from EMF Scenarios**

	Gas Volumes in Trillion Cubic Feet (Tcf) Oil and Gas Prices in 1986$/Thousand Cubic Feet (Mcf)					
	1985	1990	1995	2000	2005	2010
Upper Oil Price:						
Marketed Production	16.38	16.47	16.69	17.25	17.14	17.11
Total Imports	0.95	1.12	1.58	1.58	1.84	2.17
Total Consumption[a]	17.28	17.41	18.03	18.87	19.04	19.35
Average Wellhead Price	$ 2.57	$ 2.25	$ 3.10	$ 3.86	$ 4.50	$ 4.96
Average Delivered Price	$ 4.84	$ 4.07	$ 4.86	$ 5.72	$ 6.36	$ 6.75
Crude Oil Price	$ 4.83	$ 3.79	$ 4.83	$ 6.21	$ 6.90	$ 7.59
Lower Oil Price:						
Marketed Production	16.38	15.19	14.45	14.92	14.07	14.79
Total Imports	0.95	0.93	1.43	1.39	1.56	1.69
Total Consumption[a]	17.28	15.94	15.67	16.14	15.47	16.43
Average Wellhead Price	$ 2.57	$ 1.86	$ 2.54	$ 3.10	$ 3.71	$ 4.17
Average Delivered Price	$ 4.84	$ 3.59	$ 4.22	$ 4.84	$ 5.50	$ 6.03
Crude Oil Price	$ 4.83	$ 2.41	$ 2.93	$ 3.62	$ 3.97	$ 4.48
Lower Resources:						
Marketed Production	16.38	16.07	15.41	14.84	14.07	12.92
Total Imports	0.95	1.17	1.70	2.23	2.74	2.88
Total Consumption[a]	17.28	17.07	16.88	16.88	16.63	15.77
Average Wellhead Price	$ 2.57	$ 2.40	$ 3.38	$ 4.93	$ 5.59	$ 7.28
Average Delivered Price	$ 4.84	$ 4.22	$ 5.19	$ 6.82	$ 7.56	$ 9.36
Crude Oil Price	$ 4.83	$ 3.79	$ 4.83	$ 6.21	$ 6.90	$ 7.59
High Demand:						
Marketed Production	16.38	16.73	17.31	18.12	18.13	18.76
Total Imports	0.95	1.12	1.65	1.95	2.26	2.52
Total Consumption[a]	17.28	17.66	18.69	19.84	20.12	21.21
Average Wellhead Price	$ 2.57	$ 2.34	$ 3.26	$ 4.28	$ 4.95	$ 5.77
Average Delivered Price	$ 4.84	$ 4.14	$ 4.99	$ 6.09	$ 6.84	$ 7.57
Crude Oil Price	$ 4.83	$ 3.79	$ 4.83	$ 6.21	$ 6.90	$ 7.59

Averages for seven U.S. models; excludes GRI Hydrocarbon for which no consumption or imports were reported.
[a]Consumption excludes changes in inventories and unaccounted for.

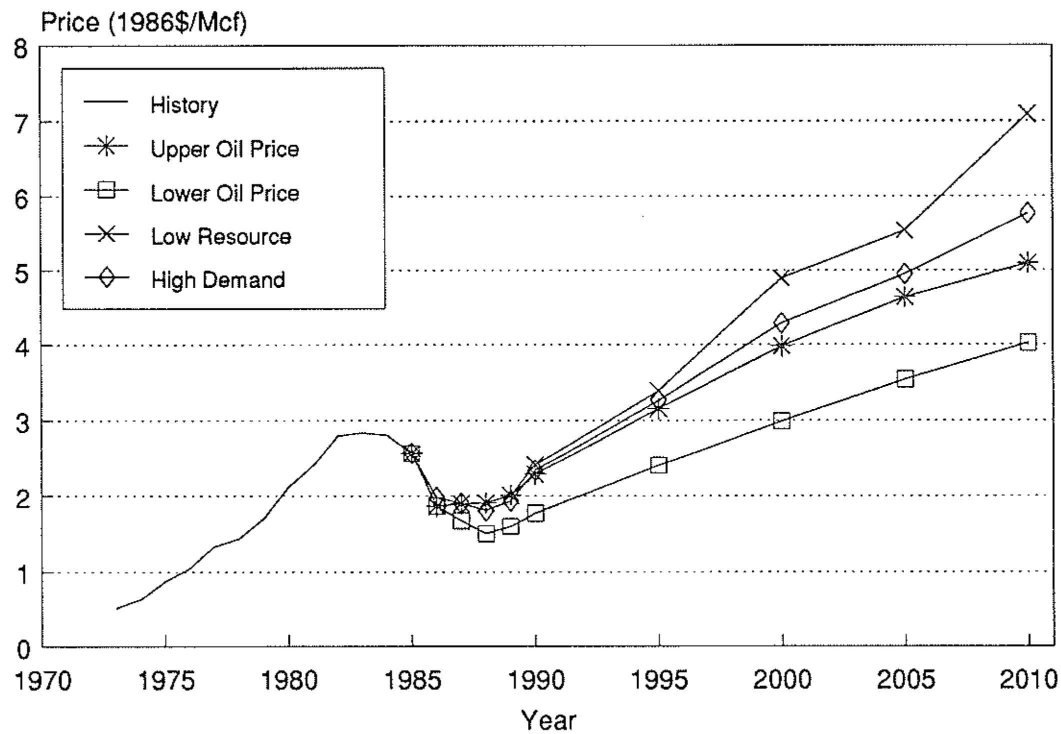

Figure 1: Model Means for Average U.S. Wellhead Price by Scenario

more in balance, gas prices in the United States and Canada rise continuously in the scenarios analyzed. Prices increase most rapidly in the low resource case and least rapidly in the low oil price scenario. By 2000, the inflation-adjusted gas price exceeds its early 1980s peak of almost $3 per thousand cubic feet (*Mcf*) in 1986$, even in the low oil price case.

Through the early 1990s, higher gas prices reflect increases in oil prices and the elimination of today's excess deliverability condition. Over the long run, *wellhead gas prices* reflect the higher cost of finding and developing gas reserves. Over the next 25 years, the results show that the U.S. gas industry will need to find and develop another 350 to 400 trillion cubic feet (*Tcf*) of reserves. Increased drilling productivity, above that represented in the model runs, could reduce the rate of cost increase but is unlikely to reverse the upward trend in costs and prices. In addition, price volatility around these long-run trends can be expected as the industry adopts more flexible-pricing mechanisms. Seasonal conditions will contribute to swings in price as well.

As the North American natural gas industry becomes more competitive, rapid and accurate gas price signals from the wellhead through the burnertip will maintain a better balance between gas supply and demand. Moreover, in the long run, natural gas and residual fuel oil prices need not necessarily track each other on a *Btu* (i.e., heat content) basis. Simple "rules-of-thumb" relating the two fuels, e.g., oil *netback prices*, may lead to incorrect forecasts and decisions.

There currently exists considerable capability for switching between natural gas and residual fuel oil in equipment that can burn either fuel (the dual-fuel market). When gas supplies are plentiful enough to saturate this dual-fuel market, gas prices may fall below the price of residual oil; conversely, when supplies are limited enough to cause this dual-fuel market to be lost, the gas price will rise above the residual fuel oil price. As long as a large amount of gas continues to be used by these dual-fired in-

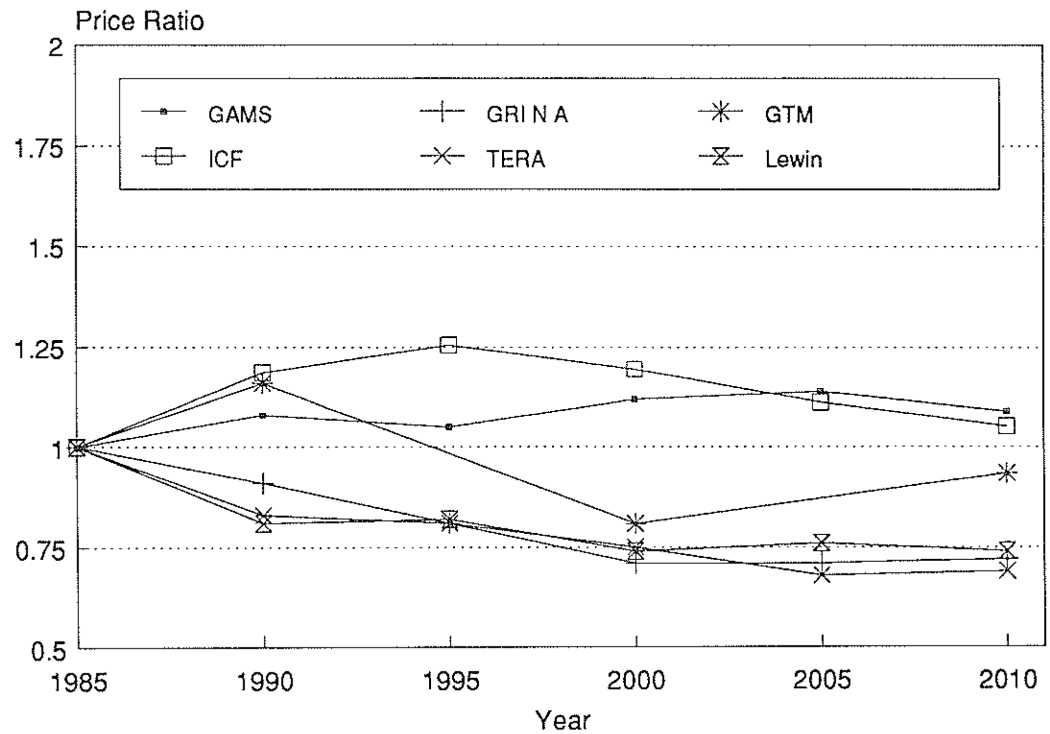

Figure 2: Industrial U.S. Gas-Oil Price Ratio by Model in the Upper Oil Price Scenario

dustrial and power-plant customers, gas prices will tend to be capped by residual fuel oil prices.

In the upper price path, sufficient gas supply is forthcoming to meet a growing gas market at industrial burnertip prices competitive with or less than residual oil prices. Half of the models show national residual fuel oil and natural gas prices in rough equivalence on a Btu basis (Figure 2).[5] In the other models, the gas price falls below the residual fuel oil price at the industrial burnertip.

Under the lower oil price conditions, industrial burnertip gas prices rise relative to residual fuel oil prices. Gas loses market share to oil as it becomes less price competitive. With oil prices only modestly higher than today's levels by 2000 ($21 per barrel in 1986$), gas prices rise above the average residual fuel oil price in those models that indicated residual oil-gas parity in the upper oil price case (Figure 3). Meanwhile, gas competes directly with residual fuel oil in those models that had indicated a gas price below the oil price in the higher oil price scenario.

Fuel Switching

Fuel switching between oil and gas, especially in dual-fired boilers, has important implications for how gas markets will adjust to changes in market conditions. As gas supply and demand conditions change, gas price change, restoring the supply-demand balance. If gas becomes more or less expensive to use than oil, the larger the amount of demand that can readily switch between gas and oil, the smaller the price change needed to rebalance demand and supply at any one time. Estimates of the amount of fuel switching capability with dual-fuel boilers vary considerably. As much as 30 percent of U.S. gas consumption may be switchable to other fuels with the lion's share being to oil—

[5] Model abbreviations in Figure 2 are identified in Table 4. Burnertip parity pricing for large industrial customers is maintained in the ICF results by the assumption that transportation costs are heavily discounted for these customers.

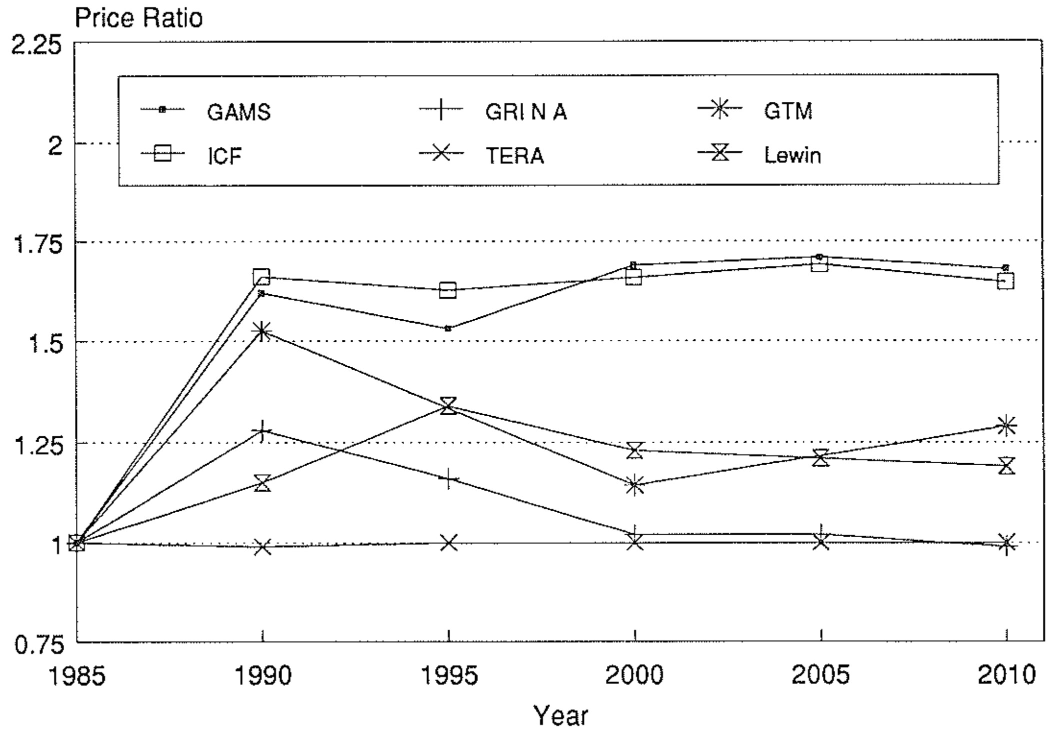

Figure 3: Industrial U.S. Gas-Oil Price Ratio by Model in the Lower Oil Price Scenario

primarily residual fuel oil—in the electric utility and industrial sectors.

This potential fuel-switching response will be critical in determining gas prices under alternative conditions. When fuel choices are very sensitive to relative fuel price changes, gas prices will not change appreciably in response to shifts in supply or demand conditions because large swings in gas usage will be experienced. Under these conditions, oil prices will essentially be determining gas prices. On the other hand, if fuel switching is less extensive, shifts in supply or demand conditions could cause gas prices to rise or fall sharply, with oil and gas prices diverging from each other.

Consumption (Demand)

The future level of gas demand will depend on gas and other energy prices, economic and demographic growth, technological change, regulatory and environmental policy, and the adequacy of the gas transmission and distribution infrastructure. Variations in the projections of industrial demand are quite large by 2010, ranging from a total of 4 Tcf to approximately 8 Tcf in different models in the upper oil price scenario. Much of this variation stems from fuel switching and different assumptions about the penetration of new industrial gas-fired technologies. The range in the demand by electric utilities is also large—from 2.9 to 5.7 Tcf by 2010—depending upon assumptions about environmental regulations, fuel prices, and *load* growth.

Based on the averages of the model results, total gas use (Figure 4) ranges from 16 to 20 Tcf by 2000 and 15.5 to 21.5 Tcf by 2010. Total consumption averages 19.4 Tcf in the upper oil price case by 2010, ranging from 18.4 to 21.4 Tcf, depending upon the model.

In the low oil price scenario, total gas consumption in the various results falls by between 1 and 5 Tcf by the year 2010 relative to the high oil price scenario, with an average decline of 2.9 Tcf. In the low resource case, total gas consumption falls

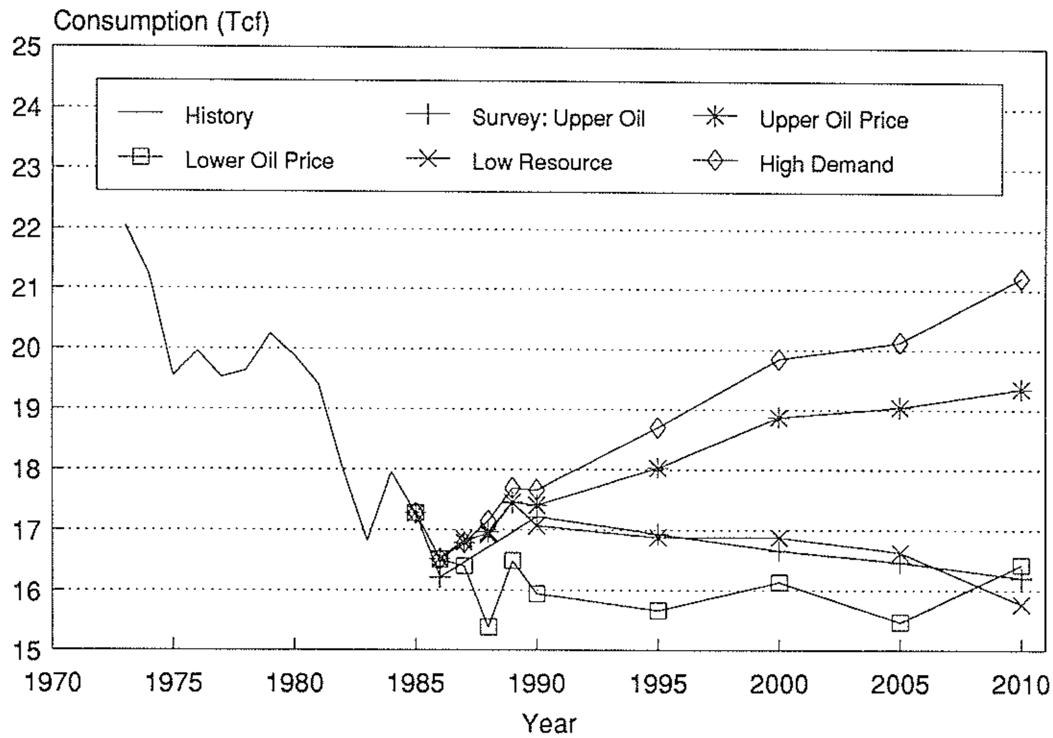

Figure 4: Model Means for Total U.S. Consumption by Scenario

by between 1 and 7 Tcf by the year 2010, with an average decline of 3.5 Tcf.

Natural gas consumption declines in both the lower oil price and low U.S. resource cases because gas becomes more expensive relative to residual fuel oil. Initially, a lower oil price causes gas users to switch to oil. Gas prices fall but not by as much as residual fuel oil prices, however, because lower gas prices reduce the incentives for gas production, making gas a scarcer, more valued fuel (relative to residual fuel oil) than before the decline in oil prices. In the low U.S. resource case, the available gas supplies are less than in the upper oil price at any given price level. In order to allocate the scarcer gas supply to higher valued uses, gas prices must rise even though oil prices remain unchanged in this scenario.

Much of the reduction in gas consumption in these two cases is due to industrial and electric utility users switching to oil. While not all lost gas consumption will be replaced by oil imports, the average declines are equivalent to 1.4 to 1.7 million barrels per day of oil use. These trends indicate increasing reliance on oil imports to replace gas. However, other indigenous fuels, e.g., coal, may also be substituted for gas.

The effect of an increase in gas demand in the electric utility sector is analyzed in the high demand scenario. Additional combined-cycle gas turbine capacity and an acid rain policy favoring gas use are assumed to augment potential gas demand in this scenario by 2.8 Tcf by 2010.

The model results indicate that higher demand levels by electric utilities can be sustained under these conditions, but gas prices must increase to bring forth the required gas supplies. The higher price encourages additional exploration and development of gas resources. It also reduces electric utility and industrial gas usage that competes with lower valued fuels (such as residual fuel oil) as well as gas consumption in other sectors. As a result, the net increase in total consumption is considerably smaller than 2.8 Tcf—between 1.5 and 2.0 Tcf by the year 2010. Increased U.S. domestic production in response to the higher gas prices accounts for most of the additional gas sold. Imports rise by less than 0.2 Tcf from their upper oil price case levels in most models, due partially to the upper bound of 2 Tcf per year imposed on Canadian gas trade.

While gas prices in the high demand scenario are higher than those in the upper oil price scenario, gas continues to be competitive in the dual fuel-burning boiler market in most models. In several models, where there is already price parity between natural gas and residual fuel oil, fuel switching by industrial customers prevents prices from rising much more with the higher demand.

Supply

The level and location of U.S. and Canadian gas production will depend on oil and gas prices, the two countries' resource bases, advances in exploration and production technology, the producer decisionmaking process, and pipeline availability to move domestic and imported supplies.

Resource Base

Future gas production depends on future reserve additions, which are influenced by future wellhead gas prices as well as by the size of the resource base. Recently, the Department of Energy (DOE)[6] and the *United States Geological Survey (USGS)* and *Minerals Management Service (MMS)* of the Department of Interior (DOI)[7] developed new U.S. gas resource estimates, which have generated some controversy.

Table 3 places the EMF scenario inputs in the context of the recent DOI and DOE estimates. The 1988 DOI estimate of un*proven* recoverable gas is 34 percent lower than its 1981 estimate—358 Tcf versus 670 Tcf—because (1) new discoveries since 1979 have caused some undiscovered resources to move into the proved reserves category, (2) drilling since 1979 has produced new geologic information that has reduced the estimated undiscovered resource in some basins, (3) DOI now uses a *play* methodology, as opposed to a volumetric approach, which reduces the amount of estimated undiscovered gas in some basins, (4) DOI is using a more explicit economic criterion in its current report for assessing how much gas may become recoverable, and (5) *tight gas* formations are explicitly excluded from the 1988 gas estimate.

The assessment of natural gas resources conducted for the U.S. Department of Energy also analyzed the major components of the natural gas supply, based upon existing resource estimates derived using established methodologies. This study found a technically recoverable resource base of 1059 trillion cubic feet of natural gas in the lower-48 states, including proven reserves (Table 3).

In addition to the traditionally defined elements of the natural gas resource base, a new component—reserve growth from heterogeneous reservoirs—is quantified in the DOE study. Disaggregation of oil reserve addition figures[8] has shown that most recent additions have been through reserve growth rather than new field discoveries. Despite the greater mobility of gas in the reservoir, the same factors of reservoir heterogeneity are believed to apply to gas. In the DOE study, a geological assessment of the gas reserve growth capacity was made on a play-by-play analysis. The result is a reserve growth potential of 180 Tcf through *infill drilling* when extrapolated across the full lower-48

[6]Fisher, W.L., Finley, R.J., Seni, S.J., Ruppel, S.C., White, W.G., Ayers, W.B., Jr., Dutton, S.P., Kuuskraa, V.A., Mcfall, K.S., Godec, Michael, and Jennings, T.V., *An Assessment of the Natural Gas Resource Base of the United States*, The University of Texas at Austin (Bureau of Economic Geology), ICF-Lewin Energy Division (ICF, Inc.), and Argonne National Laboratory, report prepared for Office of Policy Planning and Analysis, U.S. Department of Energy, under contract no. 80622401, 77 p., plus appendices (bound separately), 126 pp., May 1988.

[7]U.S. Department of Interior, U.S. Geological Survey and Minerals Management Service, *National Assessment of Undiscovered Conventional Oil and Gas Resources*, USGS-MMS Working Paper, Open-File Report 88-373, May 1988.

[8]W.L. Fisher, "Can the U.S. Oil and Gas Resource Base Support Sustained Production?" *Science*, Vol. 236, pp. 1631-1636, 1987.

Table 3: **Estimates of the Recoverable Gas Resource**

	Trillion Cubic Feet					
	PGC 1986				DOI[a]	
	Most Likely	EMF Control	EMF Low	DOE 1988	1981 Mean	1988 Mean
Undiscovered[b]						
Lower-48						
Onshore	356.1	356.2	212.4	219.0	390.2	187.7
Off-shore	109.9	116.9	61.4	134.0	102.4	74.0
Total Lower-48	466.0	473.1	273.8	353.0	492.6	261.7
Alaska, Total	109.8	n. e.	n. e.	93.0	101.2	2.4
Total Undiscovered	531.6			446.0	593.8	264.1
Lower-48						
Undiscovered Conventional (From Above)	466.0	473.1	273.8	353.0	492.6	261.7
Inferred/Probable	153.6	153.6	113.8	108.0	171.9	95.8
Unconventional at $5.00/Mcf	n. e.	97.0	0.0	146.0	n. e.	n. e.
Infill Drilling	n. e.	50.0	44.0	180.0	n. e.	n. e.
Lower-48 Unproven	619.6	773.7	431.6	787.0	664.5	357.5
Proven Reserves (end of 1986)	158.9	158.9	158.9	158.9	158.9	158.9
Unconventional above $5.00/Mcf	n. e.	37.0	0.0	113.0	n. e.	n. e.
Total Resource	778.5	969.6	590.5	1058.9	823.4	516.4

Table places EMF scenario inputs in the context of other resource estimates; it is not meant to be a rigorous comparison of estimates because: (1) economic assumptions are not the same across studies, and (2) some studies did not estimate all categories, resulting in their totals not being directly comparable.

n. e.–not estimated. PGC and 1981 DOI estimates include some unconventional gas in undiscovered category; 1988 DOI estimates include little or no unconventional in this category.

[a]The 1988 Department of Interior (DOI) estimate was developed by the United States Geological Survey (USGS) and Minerals Management Service (MMS) using different methodologies, while the 1981 DOI estimate was developed by USGS.

[b]*Potential Gas Committee (PGC)* and Energy Modeling Forum (EMF) undiscovered includes *possible* and *speculative* resource only. PGC estimate includes some gas in tight formations.

onshore *associated* and *nonassociated* gas reserve base, including *probable* resources.

Estimates of gas volume from reserve growth are less sensitive to price because this gas exists in reservoirs already discovered. In addition, since most existing fields are already attached to existing pipeline systems, this gas will be fairly low cost to bring to market, if the cost estimates for reserve growth are correct.

As shown in Table 3, the EMF low resource scenario for the lower-48 gas resource base falls close to the new DOI estimate. Moreover, the EMF estimate of 774 Tcf of unproven natural gas resources (plus 159 Tcf of proved reserves, totaling 933 Tcf) for the other scenarios is close to the DOE estimate of 946 Tcf of technically recoverable natural gas resources available in the lower-48 states.[9] Thus, the EMF cases provide a reasonable range of estimates for those who want to analyze the impacts of variations in the resource base.

Gas Costs

The costs of proving and producing reserves are as important as the extent of resources in place for determining gas supply and price. There is wide disagreement, however, over what these costs will be in different producing regions.

Costs to find, develop, and produce the gas resource are critically affected by field size, location, geologic setting, and depth of occurrence. Assumptions about these factors and the way these assumptions are implemented affect the relationships between future gas supplies and wellhead gas prices (the *supply curves*) represented in a model. The model results emphasize that these costs are at least as important as geologic estimates of the extent of the resource base in physical terms in determining gas supply. However, since most published resource estimates are given in terms of the ultimate resources yet to be discovered, market analysts must translate the published estimates into a form usable for their analyses.

As a result, despite standardizing on oil price and the physical magnitude of the resource base in this study, there were substantial differences in incremental resource costs among the models. Modelers using the same aggregate resource base are generally not using the same supply curve relating future production to prices. More optimism about supply costs leads to lower market-clearing prices and higher consumption; less optimism about these costs results in higher market-clearing prices and lower consumption. In addition, important differences in interpretation of the low resource scenario were discovered. One expert may believe that a more pessimistic resource outlook means less high-cost gas but little change in the amount of low-cost gas. To another, a lower resource base may mean less gas for all cost categories. Gas production and prices generally change more between the two resource scenarios when the gas resources for all cost categories are reduced proportionately than when only the high-cost gas resource is reduced.

Gas Production

Based on the average model results, changes in oil prices, the level of the resource base, and gas demand cause marketed U.S. gas production to range from 14 to 18 trillion cubic feet (Tcf) by 2000 and from 12 to 19 Tcf by 2010 across the four scenarios. Despite this wide range, gas production remains below 19 Tcf in all scenarios through 2010 (Figure 5), or several Tcf below its historical peak of 21.7 Tcf in 1973. Substantially higher wellhead gas prices are required to keep gas production at the upper end of this range. Generally, the models indicate that while gas supplies are definitely responsive to price, the percentage increase in marketed production is less than the percentage increase in the wellhead gas price.

Marketed production in the United States remains relatively stable at about 16 to 17 Tcf in the upper price scenario, as shown in Figure 5. Both the lower oil price and the low resource conditions

[9] This number does not include unconventional gas economic above $5.00 per thousand cubic feet (Mcf). The addition of this category would bring the DOE total to the 1059 Tcf shown in Table 3.

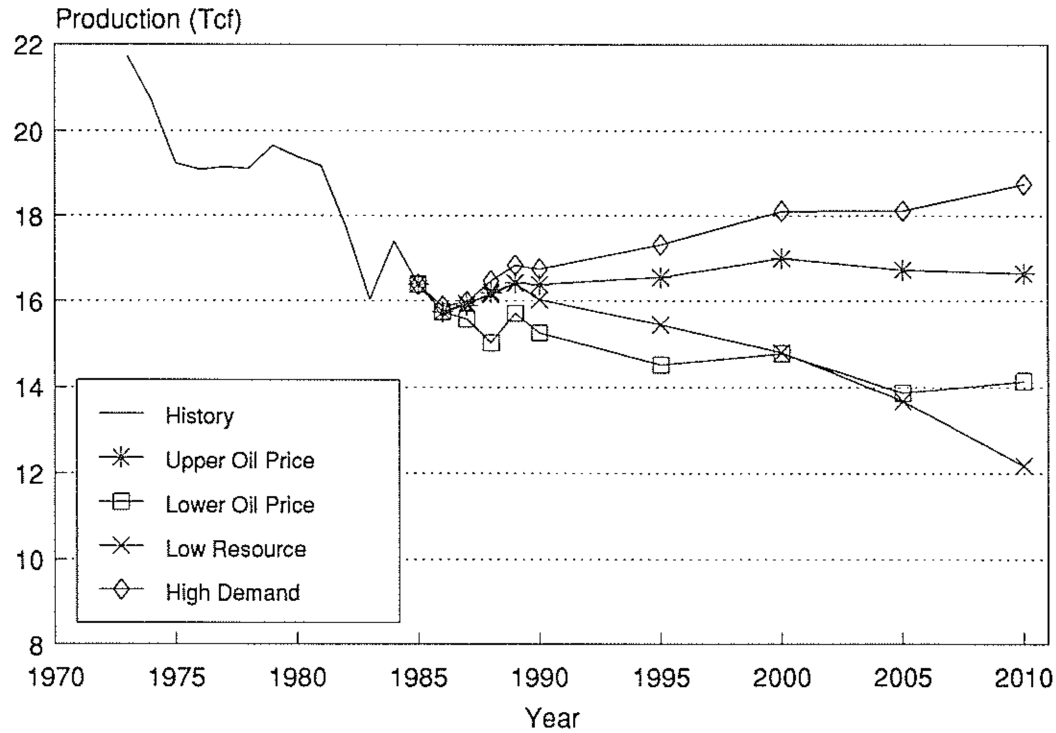

Figure 5: Model Means for U.S. Marketed Production (Dry Gas) by Scenario

result in declines in U.S. gas production relative to the upper oil price scenario. Production, on average, is 2.5 Tcf lower in 2010 in the lower oil price case and 4.5 Tcf lower in 2010 in the low resource case.

Production declines in the lower oil price case because falling gas prices reduce drilling and exploration incentives. It falls in the lower U.S. resource case because it becomes more costly to find and develop the same volume of gas as in the upper oil price case. As gas prices rise in this scenario, consumers demand less than before, resulting in lower levels of production and consumption.

A survey of industry forecasts was also compiled and averaged. Figure 6 shows that the EMF industry survey's average estimate for U.S. dry gas production with the upper oil price assumptions lies much more in line with the EMF model results for the low U.S. resource scenario through 2000. By 2010, the average survey estimate lies between the average EMF results from the upper oil price and low U.S. resource cases, but closer to the latter. The lower estimates from the survey respondents can be attributed to one or more of the following factors: a lower resource base estimate than in the EMF control resource inputs, less future spending for oil and gas drilling, and higher costs for finding and developing natural gas. For the lower price case (Figure 7), the survey respondents show less production than the modelers, the average being 15 percent lower in 2000 and about 30 percent lower in 2010.

Gas Imports

U.S. gas imports rise in all scenarios (Figure 8), reflecting the need to supplement stable or declining domestic production in meeting U.S. demand at the projected prices. In most scenarios, total U.S. gas imports reach an average of 2 Tcf or more by 2010 compared to about 1 Tcf in 1987. The import share of total consumption is higher under the low U.S. resource and high U.S. demand cases. Most of the imports are from Canada, but some of the models

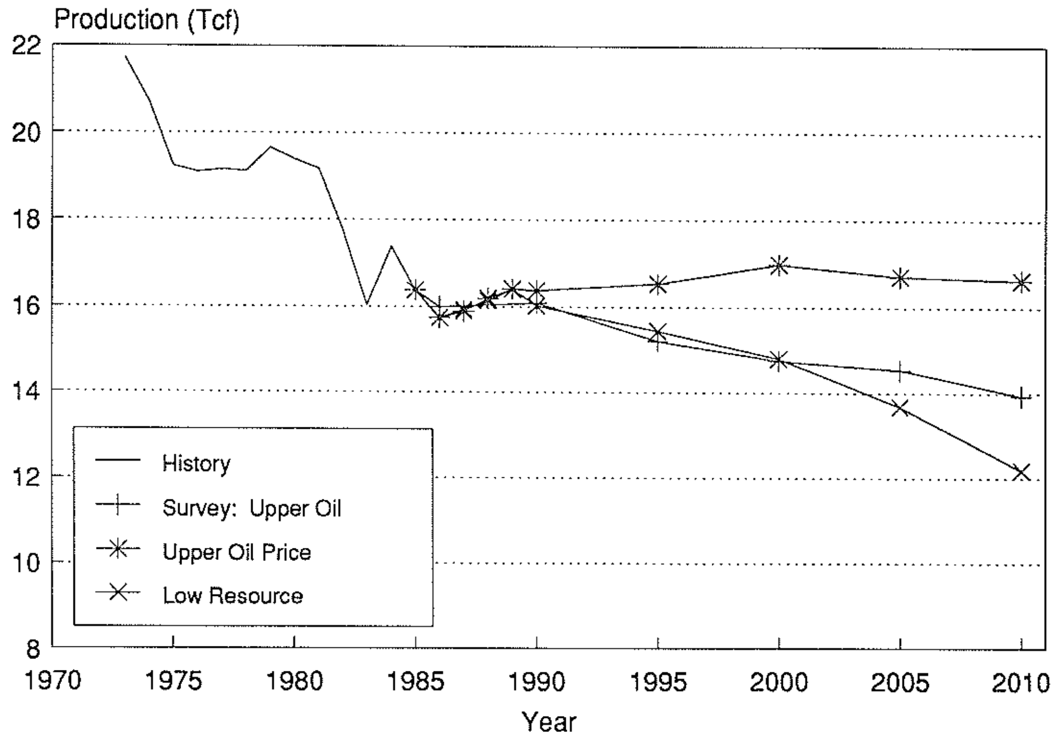

Figure 6: U.S. Marketed Production in Industry Survey and EMF Results with Upper Oil Price Path

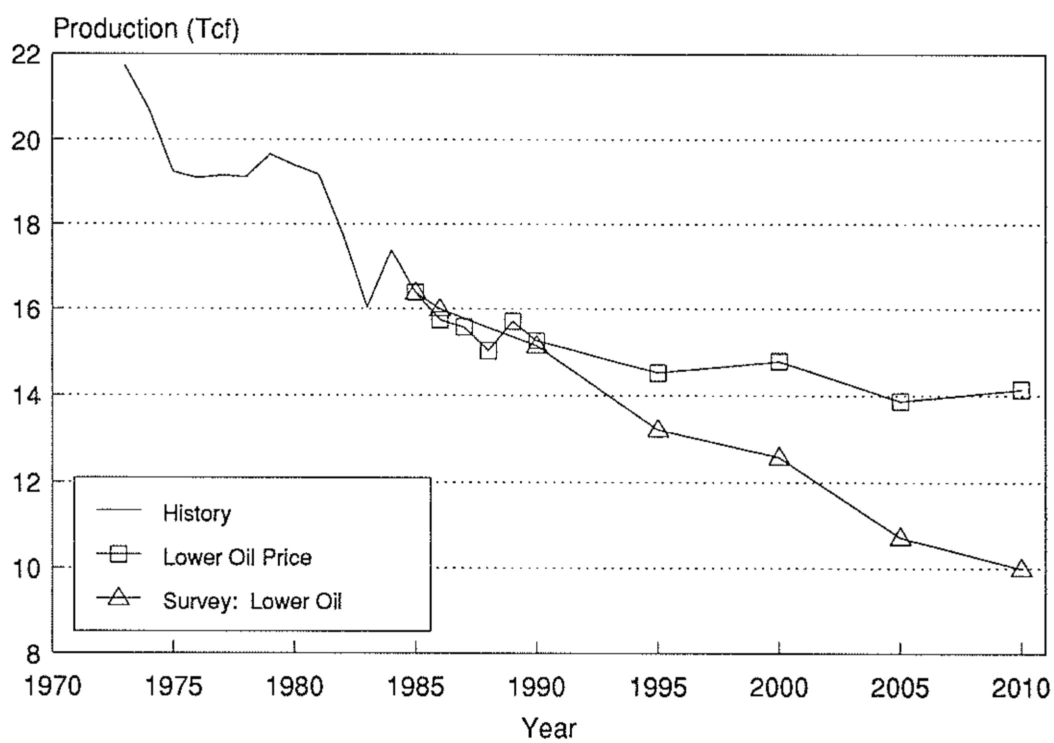

Figure 7: U.S. Marketed Production in Industry Survey and EMF Results with Lower Oil Price Path

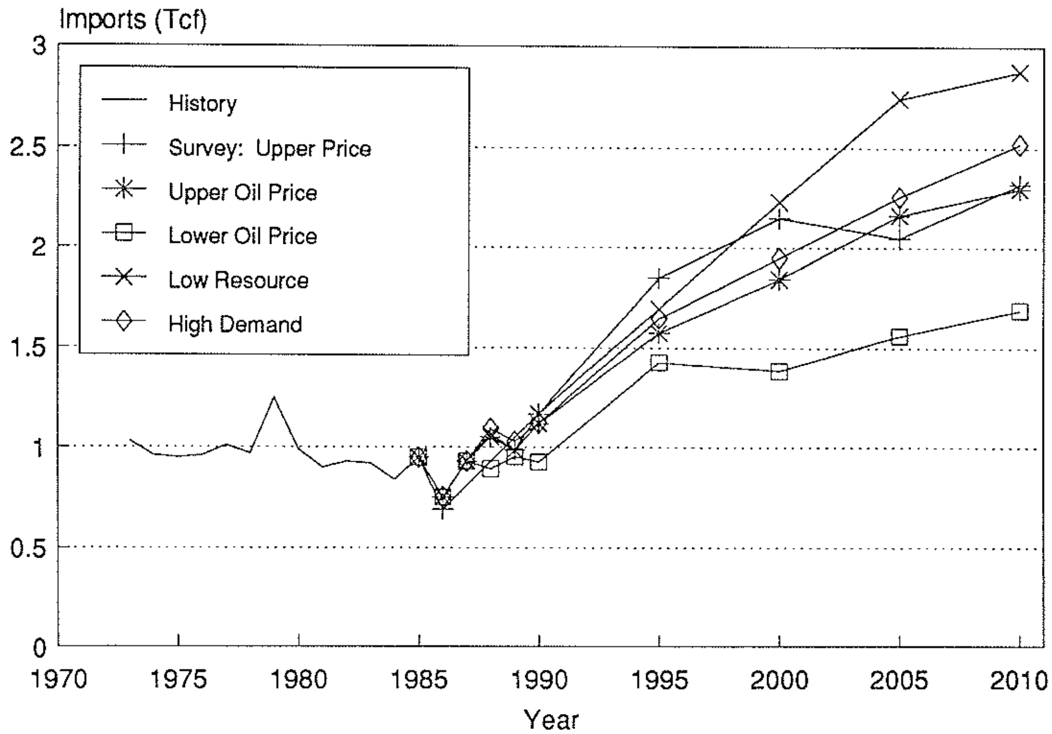

Figure 8: Model Means for Total U.S. Imports by Scenario

also include large amounts of *liquefied natural gas (LNG)* or Mexican gas.

Imports become more important in the low resource case. They rise to 2.5 Tcf by 2000 and 3.0 Tcf by 2010, increasing the import share from about 5 percent to 15-20 percent of total U.S. consumption. In the other cases, the import share rises steadily to about 10 to 15 percent of the U.S. market in this case.

To sustain Canadian gas export levels at 2 trillion cubic feet in the upper oil price case, Canadian *frontier* and *unconventional* supplies need to be developed in a timely manner for delivery after the turn of the century. Under the low oil price conditions, Canadian gas exports to the United States are likely to remain below 2 trillion cubic feet since inadequate incentives exist to maintain Canadian production and develop new transmission facilities to the United States.

The response of Canadian gas exports to different U.S. market conditions underscores the value of considering the North American gas industry as an integrated market. Many U.S. projections do not incorporate the feedbacks between Canadian and U.S. markets. In this study, Canadian gas exports are generally less in the Canadian and North American models, which incorporate these interactions, than in the U.S. models for most scenarios. These differences are particularly pronounced for the low oil price case (Figure 9).

Regulation

The U.S. gas industry has been highly regulated and the regulators' decisions have often interfered with market forces. Virtually unregulated at its beginning, the gas industry became increasingly regulated from the 1930s through the 1970s with regard to supply, demand, price, and entry. Since the late 1970s, the trend has been toward deregulation in the more competitive aspects of the industry, primarily wellhead gas sales, pipeline transportation, and end-user/*local distribution company (LDC)* gas supply.

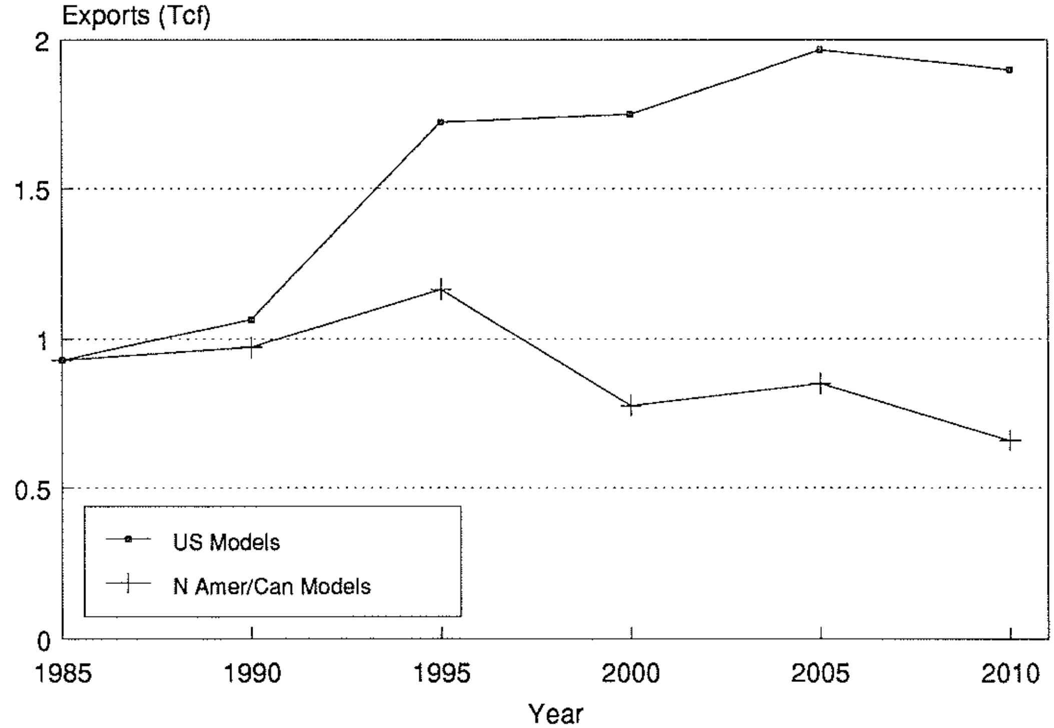

Figure 9: Total Canadian Exports in Lower Oil Price Scenario for U.S. Models and for North American/Canadian Models

A key to this pro-competitive shift is the *unbundling* of pipeline and LDC services, allowing market forces to guide the allocation of goods and services. Most important is the separation of gas sales from transportation, encouraged by partial wellhead decontrol and increasingly *open access* to *interstate* pipeline transportation. The two major regulatory issues facing the gas industry are:

1. how best to complete the process of unbundling gas sales and *transportation service*, assuming political support for pro-competitive policies continues to prevail, and
2. under what conditions to place a higher priority on regulatory objectives other than economic *efficiency*.

Key Issues in Completing the Process of Unbundling

While much progress has been made, a number of regulatory issues must be addressed in order to complete the unbundling of pipeline and LDC services:

Pipeline—FERC Issues

1. Implementation of pipeline open access—The *Federal Energy Regulatory Commission (FERC)*, in Orders 436 and 500, facilitated the unbundling of services in the interstate gas market, but difficulties in resolving *take-or-pay* concerns have slowed the transition to a more competitive market.
2. Pipeline rate structure—Even though many pipeline services will be unbundled, they will remain regulated. The rate structures used by regulators to price those services will have a significant impact on the efficiency of the evolving market, on the allocation of different types of service, and on the interplay of regulated and unregulated services.
3. *Pipeline service obligation*—Part of the tradition of public utility regulation in the pipeline

industry has been that pipelines, in exchange for monopoly privileges in a particular market, are not allowed to unilaterally reduce the level of service provided once they are officially certificated. FERC Orders 380 and 500 have reduced the obligation of local distribution companies (LDCs) to purchase gas from pipelines, but have left pipelines with the obligation to remain ready to meet the original *contract demand* levels of their LDC customers. A method of compensating pipelines for this responsibility must be found if pipelines are to remain reliable gas suppliers.

4. Economic allocation of pipeline capacity—A key aspect of pipeline rates is how they allocate pipeline capacity, especially during peak periods. On an annual basis, there is considerable excess capacity in the U.S. pipeline system as a whole, but in some segments bottlenecks exist during peak periods. Allocating capacity on these segments on an economic basis, e.g. through the use of a secondary market in capacity rights, will increase the likelihood that gas is used by those who value the space most and may provide a clearer indication of where additional pipeline capacity is needed.

5. New pipeline entry—Proposals to build new pipelines must currently move through a lengthy regulatory process. Improvements to the approval process are needed to enhance the responsiveness of the pipeline network to changes in supply and demand, while reconciling gas needs with environmental concerns and property rights.

Local Gas Distribution Company (LDC)—Public Utility Commission (PUC) Issues

6. LDC open access with unbundling—In response to the unbundling of pipeline service initiated by the FERC, many state *public utility commissions (PUCs)* are requiring utilities to offer transportation through their system on an unbundled basis. As at the pipeline level, open access at the LDC level must be reconciled with the LDC's obligation to serve, particularly in the case of large industrial customers, for whom an obligation to provide gas sales service may no longer be appropriate.

7. LDC *bypass*—Under current utility rate structures, some industrial customers find it desirable to build their own direct link to the pipeline system rather than go through their local utility. More competitive utility rate structures or legal restrictions on bypass will reduce the tendency of industrial customers to connect directly to pipelines. PUC decisions in this area are likely to be important as the gas industry evolves.

8. LDC marketing/growth policy—Historically, many PUCs, concerned about possible gas shortages resulting from wellhead price controls, have impeded the attempts of utilities to market gas service to new customers. With a largely deregulated wellhead market allowed to balance supply and demand, such policies need rethinking.

9. PUC oversight of LDC contracts—As the spot market has grown, PUCs and state legislatures have imposed a plethora of new regulations affecting gas purchasing decisions of local gas utilities. These policies are designed to encourage their gas utilities to choose a mix of long-term contracts and spot-market purchases that will ensure supply reliability and price stability at the lowest possible cost to consumers.

Regulations Affecting Canadian Natural Gas Exports

10. Canadian export policy—In 1987 the National Energy Board replaced its *surplus determination formula* for natural gas exports with a "Market-Based Procedure." This procedure has two main objectives. First, Canadians should have access to Canadian gas on terms and conditions similar to those of the proposed export (for comparable service). Second, the proposed exports should not cause Canadians difficulty in meeting their energy needs at fair-market prices. The operation of this new framework will unfold in forthcoming export applications. In addition to Canadian policies, U.S. pipeline regulations and tariffs will continue to influence the amount of Canadian gas exported to the United States.

Regulatory Policy Stability and Market Conditions

Under some scenarios, regulators may face strong political pressure to overturn some pro-competitive policies. Some of the factors which may prompt regulators to place greater priority on objectives other than economic efficiency are described below.

If delivered gas prices fall and stay below parity with delivered oil product prices, policymakers might face political pressures to raise burnertip gas prices to industrial customers with dual-fuel capability, and use the additional revenue to subsidize residential customers. Such *cross-subsidization*, however, will be possible only if industrial gas customers are restricted from buying their own gas and transporting it through the utility, or from bypassing the utility altogether.

If gas prices increase sharply, regulators may face pressure to ensure that high-priority customers (e.g., residential customers, hospitals, schools, etc.) receive the supplies they need at "just and reasonable" prices. In essence, such a strategy implies price controls for high-priority customers and cross-subsidization by lower-priority customers. In addition, a PUC may choose to disallow the recovery of some gas costs if the utility's average cost of gas rises too high. The frequent price renegotiation required under most new long-term contracts may protect LDCs from some retroactive disallowances, but there is nothing to prevent PUCs from later arguing that LDCs should have locked in low prices when the market bottomed out.

Lastly, with additional gas demand, capacity bottlenecks might become increasingly tight, leading to price increases on these segments. Regulators, seeking to protect high-priority customers, might abandon an economic system for allocating capacity and adopt fixed priorities for particular customer classes.

If industry participants believe that regulatory policies are unpredictable and may be reversed, they may respond to this uncertainty by reducing investment in gas-using capital equipment, new pipeline capacity, new gas wells, and computerized systems to cut costs in gas trading and transportation.

Natural Gas Modeling

The models used in the study were particularly helpful in organizing information about various segments of the industry into a coherent and consistent picture of the natural gas market. For example, in a competitive environment, the underlying U.S. resource base and supply conditions will affect the oil-gas pricing relationship, which will, in turn, alter overall gas demand levels and the incentives for Canadian producers to export gas. Such relationships are often difficult to follow and analyze fully without the use of a formal framework. Such use of models helped to focus the working group's discussion on the critical issues and quantify their relative importance (e.g., the relationship between oil and gas prices, the interaction between Canadian and U.S. markets, the implications of a lower resource base, and the effects of increased gas demand).

In general, the models assume competitive behavior; producers and consumers respond to price,

Table 4: **Natural Gas Models Used in EMF 9**

Model	Organization	Primary Focus
Group A:		
AGAS	Alberta Research Council	North America
GRI North American (GRI N A)	Decision Focus, Inc.	North America
Gas Trade Model (GTM)	Stanford University	North America
MIT North American (MIT)	Massachusetts Institute of Technology	Canada
Rowse	University of Calgary	Canada
Group B:		
Gas Analysis Modeling System (GAMS)	Energy Information Administration	United States
GRI Hydrocarbon (GRI Hydro)	Energy & Envir. Analysis	United States
ICF Gas Market Evaluation System (ICF)	ICF, Inc.	United States
Lewin Natural Gas Model (LEWIN)	ICF-Lewin Energy	United States
NEB Energy Demand/Gas Supply Models (NEB)	National Energy Board	Canada
A.G.A.—TERA (TERA)	American Gas Association	United States

Abbreviation of model name used in this report is shown in parentheses.

and prices adjust with shifts in supply and demand conditions. Many of the models used in the study, however, did not incorporate the regulatory environment explicitly in their frameworks.

While the models used in this study have a similar focus, they form a heterogeneous group. Those listed under Group A in Table 4 were developed primarily to study the interdependence of supply-demand balances in many different regional markets. Rather than using detailed submodels to describe drilling activities and finding rates by resource category, these models represent supply conditions as reduced-form relationships linking gas production to gas prices. These relationships are often based upon more detailed studies of the resource base and production activities. Similar reduced-form relationships are used to describe consumption as a function of price. The models focus their analyses on how gas produced in a supply region is allocated to demand regions on the basis of competitive economic conditions. These models are particularly well suited for analyzing future regional gas flows if the industry is *workably competitive* at all levels.

The models in Group B devote considerably more attention to studying the specific relationships governing supply and demand decisions in the market. They generally employ engineering-economic relationships to describe these interactions. The demand submodels usually represent residential and commercial consumption decisions with statistical equations, while using detailed submodels representing different technologies and processes to simulate industrial and electric utility decisions. These models were generally constructed for detailed studies of the economic and technical factors influencing supply and demand decisions. They were not developed primarily to analyze how regional gas flows would be allocated based upon competitive economic conditions, even though all but one were used in this study to determine market-clearing prices equating the quantity supplied to that demanded.

Methodology accounts for only a portion of the variation among model results. Different perspectives about fundamental gas supply, demand, and pricing relationships are also important explanations for why model results vary.

Both groups of modelers potentially can learn much from each other. Additional physical realities, such as leasing, exploration, development, and the production cycle, could be usefully incorporated in economic models focusing on regional supply-demand interactions. Additional economic realities of regional competition for gas flows could be usefully incorporated in engineering-economic models that represent supply and demand decisions in considerable detail.

Many of the models used in this study were originally developed to reflect a long-term, workably competitive natural gas market. Most of the models did not directly incorporate regulatory behavior in their structures, nor did they explicitly link transmission and *distribution margins* to changes in market forces. As the gas market develops, it will be important to better reflect within the model frameworks the increasing integration of the U.S. and Canadian gas markets, interregional competition within each country, impacts of regulatory behavior, technological changes in gas supply and demand, alternative natural gas resource base estimates, transmission and distribution margin development, price volatility, environmental regulations, and short-run dynamics. Developing better analyses of these factors will improve decisionmaking and represents an important challenge.

Further Research

During the study, the group identified several natural gas industry issues, listed in Table 5, that required additional research. Some of the topics require theoretical analyses (e.g., effects of regulatory decisionmaking on the gas industry's structure and behavior, and gas price volatility) before they can be modeled. Other issues that are understood theoretically require more accurate data (shape of the gas demand curve and fuel switching) to improve the analysis. Several analysts have already begun work on some of these issues. Nevertheless, further resolution of these uncertainties is needed. A better understanding of these issues, both theoretical and quantitative, will improve analyses and decisionmaking within the gas industry at all levels—regulatory, producer, distributor, pipeline, and end-user.

Table 5: **Issues Identified by the EMF 9 North American Natural Gas Working Group as Requiring More Analyses**

1. Modeling of Regulations
2. Transportation and Distribution Rates
3. Regional Wellhead Price Differentials
4. Interaction of Canadian and U.S. Gas Markets
5. Price Volatility and Seasonality
6. Shapes of Gas Supply and Demand Curves
7. Potential Fuel Switching
8. Gas Conservation
9. Effect of Electric Utility Deregulation on Natural Gas Use
10. Impact on Natural Gas Use of Advanced Gas/Non-Gas Technologies
11. Potential for Natural Gas as a Transportation Fuel
12. Supplemental Gas Supplies (e.g., LNG, Alaska, Canadian, Frontier, etc.)
13. U.S. and Canadian Resource Bases
14. Effects of Advanced Gas Drilling and Production Techniques
15. Effect of Environmental Regulations on Gas/Oil Drilling and Production
16. Pipeline and Storage Capacities

Appendix

A Glossary of Economic and Industry Terms Used in the Summary Report

Associated Dissolved Gas Natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

British Thermal Unit (BTU) The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at or near 39.2 F.

Burnertip The point of end-use consumption of a particular fuel, most often natural gas or residual fuel oil.

Bypass The ability of industrial customers to obtain gas directly from a pipeline and thereby circumvent local distribution companies.

Combined-Cycle Gas Turbine A turbine that uses the waste heat from an initial stage turbine as fuel for a second-stage turbine. Higher heating efficiency relative to a single-cycle gas turbine is the result.

Contract Demand The amount of gas a seller agrees to deliver on a daily basis for a specific price in accordance with a service agreement. The buyer need not take this maximum quantity on any given day.

Cross-Subsidization The practice of charging rates higher than actual costs to industrial and utility customers and passing on lower rates to residential and commercial customers.

Distribution Margin The excess of LDC gas revenue over LDC total gas purchase costs divided by throughput. On a system basis, end-user gas cost minus citygate gas cost.

Efficiency An economic condition in which resources are allocated to move "as far as possible in the satisfaction of wants within resource and technological constraints." (*New Palgrave*, ed. by J. Eatwell, M. Milgate, P. Newman; New York: Stockton, 1987, Vol 2, p. 107).

Energy Modeling Forum An international activity headquartered at Stanford, devoted to improving application of analytical techniques to energy policy and planning.

Federal Energy Regulatory Commission (FERC) The Federal agency with jurisdiction over natural gas pricing, wholesale electric rates, hydroelectric licensing, oil pipeline rates, and gas pipeline certification.

Frontier Frontier areas are new, large, relatively remote and unexplored areas that are expected to be productive. Examples are the Beaufort Sea and offshore Atlantic areas of Canada.

Fuel Switching The ability of a boiler to burn alternate fuels, such as gas or residual fuel oil. Switching occurs when one fuel is substituted for another on the basis of price and can be categorized by the rate at which it occurs:

- Very short-term switching of gas to an alternate fuel in dual-fired boilers. Much of this switching would be to residual fuel oil.
- Intermediate term switching through retrofits to make gas boilers which can only burn gas, dual fired with other fuels.
- Longer-term switching of gas equipment to totally or partially use non-gas fuels.

Gas Bubble The persistent excess of national gas deliverability above market demand. Deliverability, or the maximum rate at which a well or field can produce, is the important factor, not actual production.

Gas-to-Gas Competition The competition between different gas suppliers competing for markets. Primarily a function of decreasing demand, the presence of multiple pipelines serving particular markets, and excess deliverability.

Infill Drilling Reducing the effective spacing in already developed fields by drilling between existing wells. This is a means of recovering incremental reserves or accelerating reserve recovery.

Interstate Transmission of gas across state lines.

Liquefied Natural Gas (LNG) Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

Load The amount of electric power or gas delivered or required at any point on a system. Load originates primarily at the energy-consuming equipment of the customers.

Local Distribution Company (LDC) A company that obtains the major portion of its gas revenues from the operation of a retail gas distribution system and that operates no transmission system other than incidental connections within its own system or to the system of another company.

Mcf One thousand cubic feet of natural gas at 60F and atmospheric pressure at sea level. Roughly equivalent to a million Btus.

Minerals Management Service (MMS) A department in the U.S. Department of Interior that is charged with overseeing leasing operations and reserve analysis in offshore U.S. areas.

Netback Pricing A calculation that involves starting at a competitive fuel burnertip price and calculating backwards through the system, incorporating distribution and transmission charges, to arrive at the resultant wellhead gas price.

Nonassociated Gas Natural gas that is unassociated with conventional oil. Exists in the reservoir as a dry gas phase. Liquids may condense and be a separate phase at the wellhead, but they contain much lighter hydrocarbons than conventional oil.

Open Access Non-discriminatory transportation of gas on a first-come first-served basis. First initiated by FERC Order 436 in October 1985.

Pipeline Service Obligation The contractual obligation of pipelines to hold supplies sufficient to meet the contractual demands of customers.

Play A term for a geologic prospect that has not been drilled yet. Usually refers to an exploration target.

Possible Reserves Resources that are a less assured supply source because they are postulated to exist outside of known fields, but are associated with a productive formation in a productive province.

Potential Gas Committee The PGC consists of volunteer members from the natural gas industry, government agencies, and academic institutions who provide estimates, based upon expert knowledge, of the potential supply of natural gas which, in conjunction with estimates of proved reserves of natural gas, make possible an appraisal of long-range gas supply.

Probable Reserves Inferred resources associated with known fields that are the most assured of potential supplies.

Proven Reserves The currently estimated quantities of gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions, and technology.

Public Utility Commission (PUC) A state regulatory body that governs intrastate gas movements and Local Distribution Company operations within a particular state.

Residual Fuel Oil Fuel that remains after the removal of valuable distillates (gasoline) from petroleum. Different classes of residual fuel oil are based on differing physical properties, and are used in different applications. Generally, the higher the sulfur content of residual fuel, the lower the price it commands on a Btu basis.

Resource Base The amount of natural gas that is yet to be recovered. In order for reserves to be included in the "resource base", they must be recoverable using current or foreseeable future technology.

Speculative Reserves Resources expected to be found in formations or provinces that have not yet been proven to be productive.

Spot Market The market for gas supplies in which gas is sold to the highest bidder without any long-term commitment to sell or buy gas.

Supply Curve An economic representation that depicts the amount of production that can be brought forth at different prices in a given time period.

Surplus Determination Formula A procedure that is used to determine whether proposed gas for export in Canada is in excess of domestic needs and can be exported to the U.S.

Take-or-Pay Amount of gas required to be purchased and paid for, even if not taken. Some quantities are based on minimum daily quantities, annual quantities, or minimum contract quantities. Take-or-pay quantities may change over time under initial provisions of the contract or may be changed in an amendment to the contract.

Tcf One trillion cubic feet of natural gas at 60F and atmospheric pressure at sea level. Roughly equivalent to 1 Quad or 0.5 million barrels per day of oil.

Tight Gas Gas that lies in formations with very few pores or openings permitting the flowthrough of gas and liquids. (Permeabilities are generally below .01 millidarcy).

Transportation Service Pipelines act solely as a transporter of gas, moving gas from receipt to delivery point without taking title.

Unbundling The separation of pipeline services into discrete components, e.g., transportation, storage, firm service, etc. With unbundling, separate fees are charged for each service.

Unconventional Reserves found in coal seams, Devonian shales or extremely low permeability formations that often require stimulation or secondary recovery mechanisms.

United States Geological Survey (USGS) A department in the U.S. Department of Interior with responsibilities for geologic analysis, research, and reserve estimates pertaining to U.S. domestic areas.

Wellhead Price The price received by the oil or gas producer for sales at the wellhead, including charges for natural gas plant liquids subsequently removed from the gas, gathering and compression charges, and State production, severance, and/or similar charges.

Workably Competitive A market that has sufficient numbers of buyers and sellers, with no one firm or group of firms exercising any significant control over the market, such that interfirm rivalry will eliminate most distortions to an economic efficienct allocation of resources.