

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILE 8672
1624 SCOMM 62 • SENATE SPEC. COMM. ON OIL & GAS, 1989-1990

II. DOMESTIC NEED FOR THE NORTH SLOPE GAS

The ERA has declared that domestic U.S. need for the gas is an important consideration in this proceeding. Let me make clear our understanding that a determination of domestic "need" for the Alaskan gas must be based on an economic test. If the gas is reasonably expected to be saleable on a free-market basis in the lower-48 states, without government subsidy, then it meets this prima facie test. By definition, if competitively-priced Alaskan gas is not available, demand for that energy could be met only if American consumers make use of higher priced and/or less desirable alternatives.

The currently proved Prudhoe Bay gas reserves, delivered to the lower-48 states by a pipeline system, can meet this free-market test based on the following considerations:

--Cost of the ANGTS. The revised cost estimate for the remaining elements of the ANCTS and use of a levelized tariff will make the delivered gas price highly competitive domestically during the proposed period of export. Mr. Cuba Wadlington, our Vice President for Regulatory Affairs, will elaborate on this and will also cover the concept we are considering for marketing the gas.

--Independent Supply/Demand Forecasts. Reasonable forecasts of a domestic "need" for the Alaskan gas during Yukon

Pacific's ostensible period of export (i.e., 1996-2021) 2/ have been made by independent, respected analytical organizations such as the Gas Research Institute ("GRI"), and have already been placed in the record. 3/

A new study lends additional weight to those we have previously cited. Entitled "Natural Gas: A Strategic Resource for the Future," it was prepared by the Washington Policy and Analysis consulting group ("WPA Report"), using a number of highly experienced energy professionals under the direction of a former Deputy Secretary of Energy. 4/ Regarding delivery of North Slope gas to the lower-48, it concludes that:

Precise timing is difficult to forecast, but it is reasonable to conjecture that a suitable pipeline could go into service within the first decade of the 21st century. This was one of the assumptions used in projecting supply to support the 'accelerated U.S. gas-use scenario' [that is recommended by the study team]. . . . (p.9)

In broader perspective, the study authors reported:

2/ Yukon Pacific's proposed "1996" starting date is likely to slip significantly in view of the following facts: (1) no gas sales commitments have been obtained; (2) no gas purchase agreements have been consummated; (3) no financing has been arranged; (4) the North Slope gas conditioning facility, a critical-path item with substantial regulatory ramifications, remains in limbo; and (5) Yukon Pacific, by its own admission, has not even commenced basic engineering of the system.

3/ Various supply/demand studies were introduced by Alaskan Northwest in its comments of August 24 and September 27, 1988. The GRI, as one example, projects commencement of Alaskan pipeline gas flow in 2007.

4/ Washington Policy and Analysis is a Miller and Chevalier Consulting Group; the study was released November 28, 1988. (Copy attached as Exhibit A.)

. . . a formidable and rapidly growing national consensus on the multi-faceted promise of natural gas for the rest of this century and into the next . . . [and] its increased use is an indispensable factor in the kind of mixed-and-balanced energy equation that best suits the nation. (pp. 1, 38)

--U.S. National Energy Security. Domestic demand for natural natural gas is almost certain to grow beyond current forecasts due to the rapidly increasing U.S. dependence on foreign oil, now over 40% and expected to be about 70% by 2010. ^{5/} Our nation obviously will become dangerously vulnerable to oil supply disruptions and/or price shocks. Much greater use of domestic natural gas predictably will become a public policy imperative as an important means to limit this vulnerability. The aforementioned WPA Report (Exhibit A), in a comparison to its "conventional wisdom" base case, concludes that the greater use of natural gas that WPA forecasts will result in a 2 million barrel per day reduction in demand for imported oil. The ANGTS, at full capacity, will provide the energy equivalent of 30 percent of this total--an impressive contribution to U.S. energy security by any measure.

President Bush, in addressing means to enhance U.S. national security last year, declared:

^{5/} See the WPA Report, page 25. See also the tabular comparison of the Baseline and Accelerated-Gas-Use Cases modeled by the WEFA Group (a merger of Chase Econometrics and Wharton Economic Forecasting Associates), as a backup to the WPA Report, dated November 22, 1988, "Baseline Scenario" (Table 8.2) for 2010, which projects a U.S. dependency on imports of 73% for crude petroleum and natural gas liquids.

There's no security for the United States in foreign oil. 6/ . We must turn to alternatives like natural gas.

--Environmental Requirements. Concern is growing about the damaging environmental effects of acid rain, ground-level ozone, carbon monoxide, atmospheric particulates, and the "green house" effect. Increased use of natural gas clearly can improve the situation, as we have previously established in the record. More stringent standards appear inevitable and will result in increased demand for natural gas. The WPA Report (Exhibit A) concludes:

A major force driving the introduction of more natural gas into the U.S. economy in the future could be an effort to meet environmental standards in the most cost-conscious manner. (p.19)

An even more compelling case is made in a report with recommendations by the National Academy of Sciences, the National Academy of Engineering and the Institute of Medicine, in concert, to President Bush, as follows:

. . . we should explore means for reducing energy demand without impeding economic growth, for example, by using fossil fuels with greater efficiency, as well as incentives and other means to increase use of the 'cleanest' fossil fuels such as natural gas. However, the finite availability of natural gas, a premium source and valuable chemical feedstock, also needs to be considered. (Emphasis added) 7/

6/ George Bush, Leadership on the Issues, November 1988, page 103. The statement was made on October 16, 1988.

7/ See National Academy of Sciences, National Academy of Engineering, Institute of Medicine, "Global Environmental Change, Recommendations for President-Elect George Bush," released January 5, 1989, page 3.

--Imports Are Not Enough. It is unrealistic to assume that U.S. imports of gas from Canada, Mexico, or of LNG can be obtained essentially without limitation, indefinitely and at more attractive prices than Alaskan pipeline gas. As we have previously pointed out, credible forecasts which take both price and availability into consideration call for gas from an Alaskan pipeline in addition to substantially increased foreign imports. The WPA Report (Exhibit A) reinforces this view. The Canadian National Energy Board, moreover, recently released a revised energy supply and demand forecast through 2005 which envisions an increasing Canadian reliance upon gas from "frontier" areas starting in 1999. ^{8/} Gas from these areas, including the Mackenzie Delta and Arctic Islands, will be subject to many of the same economic costs faced in constructing the ANGTS from a remote Arctic area.

Mexican gas imports do not appear to be a likely source of substantial future supply. Mexican Government policy is to maximize the use of natural gas domestically in order to obtain as much foreign exchange credits as possible from the sale of oil.

Regarding LNG imports, when the limited unused capacity in existing domestic terminals is used up, any additional capacity can then only be obtained by a costly,

^{8/} See Canadian National Energy Board, Canadian Energy: Supply and Demand, 1987-2005, September 1988 (Released December 7, 1988), pp. 114-118.

controversial and protracted process of siting and environmental approvals of major new terminals. Obviously, any increase in imports can only worsen our trade balance. It seems clear, therefore, that the U.S. gas market will be served by a variety of sources, each with its limitations; in such an environment, the overland delivery of the Prudhoe Bay reserves should be highly competitive. These reserves, therefore, are needed domestically.

--Potential Electric Power Generation Shortfalls. There is a very serious looming shortfall of electric power generation capability in the U.S. in the next ten years and into the next century. Natural gas turbines, which can be constructed relatively quickly and at far less cost than any type of steam-generating plant, are probably the only realistic hope this nation has to avert power shortages. I will elaborate.

The U.S. Energy Information Administration ("EIA") recently projected a base-case need for about 127 gigawatts of additional electric generating capacity by the year 2000, including about 33 gigawatts currently under construction. ^{9/} This total is equivalent to about 127 major new nuclear power plants. It is a conservative statement of need and assumes that major investments are

^{9/} A "gigawatt" equals 1,000 megawatts, the approximate capacity of a major electric utility generating plant.

made to extend a large number of existing electric generating plants beyond their normal retirement dates. If such life-extending investments are not made, the total requirement for new capacity by 2000 would be about 148 gigawatts. 10/

The American Gas Association ("AGA"), drawing on a number of other relevant studies, including those recently conducted by the North American Electric Reliability Council ("NERC"), concluded that between 50 and 105 gigawatts of new capacity will be required by 1997 in addition to plants currently under construction. 11/

The significance of these projections is the 10- to 12-year lead times required for regulatory approval and construction of new steam generation plants. Obviously, the lead time for such construction is being dissipated by every passing month. In the meantime, natural gas combined cycle or combustion turbines, which have far shorter lead times and are much less costly, are rapidly taking over the major share of future planned

10/ See Energy Information Administration, U.S. Department of Energy, Annual Outlook for U.S. Electric Power 1988, Projections Through 2000, August 24, 1988, page ix, Table ES1, et seq.

11/ See American Gas Association, Trends in Electric Generation Capacity and the Impacts on Natural Gas Demand, January 23, 1989. (Copy attached as Exhibit B.)

construction. 12/

The plain result of this growing trend in reliance upon natural gas for electric power generation has not yet been fully reflected in most supply/demand projections. The recent WPA Report, however, states:

. . . we felt confident with a detailed analysis that showed gas supplying nearly one-sixth of the primary energy used in generating electricity by 2010. This alone would require about 6 trillion cubic feet of gas annually, or more than twice as much as is being used now by the electricity industry. (Emphasis in original)

Two additional points are relevant: First, there is no question today as to the reliability and cost superiority of gas turbines for baseload power-generation purposes. 13/ Second, a unique attribute of North Slope gas, primarily as a result of the magnitude of the proven Prudhoe Bay reserves, is its ability to provide a long-term (up to at least 25 years), assured source of supply that will become increasingly important for the construction and financing of baseload electric generating plants.

--Summary of Domestic Need. We believe, in summary, that the accelerating demand for energy and particularly natural gas will burgeon in the years ahead, become highly

12/ See North American Electric Reliability Council, 1988 Reliability Assessment, the Future of Bulk Electric System Reliability in North America 1988-1997, September 1988, p. 20, 31.

13/ See Electric Power Research Institute, "Utility Turbopower for the 1990's," EPRI Journal, April/May 1988, pp. 4-13.

visible, and exceed most current projections by a wide margin. By any reasonable assessment, the Prudhoe Bay gas reserves will be needed by American consumers during Yukon Pacific's proposed period of export, even without slippage in its proposed 1996 starting date. When a major increase in U.S. domestic demand for gas becomes obvious--as it surely will--will Americans wake up and find that their major assured source of long-term supply has been committed to foreign export?

III. APPROVAL OF THE REQUESTED EXPORT
LICENSE SHOULD BE DENIED

The reasonably projected domestic need for Prudhoe Bay's proven gas reserves established by law, documented in the record of this proceeding, and briefly discussed above should by itself be sufficient for ERA to conclude that it must avoid any action that might jeopardize the overland delivery of that gas to American consumers. What remains to be discussed is: Why should commitment of the Prudhoe Bay gas to export be denied? There are two compelling reasons for denial:

1. Insufficient proved and economically transportable gas reserves exist on the North Slope to warrant construction of two major gas conditioning plants and two large-diameter pipeline systems in the same time frame.

The ANCTS has always relied upon the 26 tcf of proved gas reserves at Prudhoe Bay, notably gas associated with the production of oil and then reinjected into the Prudhoe Bay Field. This is well established in the President's Decision of

September 1977 and elsewhere in the regulatory record. ^{14/} This gas requires minimal gathering or production expenditures. Moreover, it is concentrated in a small area with substantial existing support facilities. For these reasons, together with the large quantity of proven reserves, the Prudhoe Bay gas is truly the "cream" or "highgrade" of whatever gas may exist on the North Slope. These considerations would be important anywhere else in the world. But they are of critical importance to economic viability in the Arctic. With respect to any potential North Slope gas sources other than the Prudhoe Bay Field, I can say with reasonable confidence that, even under the best of circumstances, uncertainties as to gas availability, transportability, and costs will delay any major pipeline project relying on such potential alternatives until long after a project using the Prudhoe Bay gas comes on stream.

The Yukon Pacific Application to ERA clearly spelled out its intention to rely upon the Prudhoe Bay gas reserves:

Yukon Pacific's supply procurement efforts will focus primarily on purchasing natural gas produced from the Prudhoe Bay oil field and, in particular, the gas cap from Prudhoe Bay's main oil producing formation--the Sadlerochit formation. (p. 13)

We have previously introduced expert statements by Mr. James

^{14/} See, for example, the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, September 22, 1977, Section II, paragraph 2: "The expected volume of gas to be available initially from the Prudhoe Bay Field is 2.0 to 2.5 billion cubic feet per day...." The Report (p. 89) stated that this would include production from the main pool as well as the Kuparuk and Lisburne reservoirs in the Prudhoe Bay Field.

Jensen of Jensen Associates, Inc. regarding the "highgrading" of gas reserves, as intended by Yukon Pacific, and the probable effect on the ANGTS. Mr. Jensen will provide additional testimony on this subject today. The choice is clear for the reasonably foreseeable future, extending well into the next century, to wit: gas for American consumers when needed or Prudhoe Bay gas committed to export for foreign users, but not both.

2. A variety of legal grounds preclude approval of the export application.

We have already placed legal arguments and evidence into the record as to why an export license should not be issued or, at a minimum, should be strictly conditioned. I will not today further elaborate upon those matters, other than to reemphasize that the ANGTS sponsors have already invested about \$1.5 billion dollars in good faith reliance on explicit government representations. We will take all necessary actions in the appropriate forums to protect the sponsors' interests in that investment and will continue to work toward the stated national objective of providing Prudhoe Bay gas to lower-48 consumers. Mr. William J. Moses, General Counsel of Northwest Alaskan Pipeline Company and Mr. William J. Grealis, of the law firm of Akin, Gump, Strauss, Hauer and Feld, are available to answer questions.

IV. CONDITIONS REQUIRED IF YUKON
PACIFIC'S APPLICATION IS NOT DENIED OUTRIGHT

Throughout this proceeding, Alaskan Northwest, taking into consideration all of the points we have previously addressed and placed into the record, has strongly maintained that if any export license is issued to Yukon Pacific, it must include specific conditions along the following lines: (1) the proven Prudhoe Bay reserves needed to supply the ANGTS are not depleted; (2) construction of the ANGTS facilities has priority over those of the Trans Alaska Gas System ("TAGS") in order to avoid incurring additional costs that would be borne by U.S. consumers and rate-payers; (3) an appropriate cost allocation methodology is devised if the ANGTS facilities are used for the TAGS project; and (4) the ANGTS project has first call on North Slope gas for delivery to the lower-48 states, if it is needed to meet contractual obligations or to preserve the project's economic viability.

Furthermore, in order to implement these conditions and ensure that consumers and rate-payers are shielded from any and all costs associated with the proposed export, Alaskan Northwest maintains that any such authorization must not proceed in the absence of full NGA Section 7-type informational and filing requirements and must be further conditioned in one of two forms--either (i) mandatory curtailment and diversion of exports to meet lower-48 needs; or (ii) imposition of full economic liability for all costs (e.g., environmental, socioeconomic) associated with the non-availability of the exported volumes and

the forced domestic utilization of more expensive or less desirable fuels.

V. CONCLUDING REMARKS

In closing, I want to reiterate the ANGTS sponsors' conviction that the Prudhoe Bay gas reserves will be needed by American consumers and should be preserved for that purpose. Only the precise timing of an overland pipeline delivery system cannot be specified.

We believe, therefore, that it would be a tragedy for the United States if this major source of clean-burning domestic fuel and chemical feedstock, constituting the nation's largest remaining block of proved gas reserves, is committed to export. If it nevertheless is committed to export, I sincerely believe that we will look back on that event as an historic blunder.

Natural Gas: A Strategic Resource
For the Future

WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP

Exhibit A

**A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP**

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Natural Gas: A Strategic Resource for the Future

It is time to get specific about adapting this country's natural gas *policies* to its economic, security, and environmental *goals*.

For the third year, U.S. oil imports have jumped. Given the realities of energy resource distribution around the world, the future promises a tightening world oil market, increasingly dependent on the volatile Middle East. Such a future poses risks of oil-price shocks and oil-supply disruptions in the 1990s . . . while concerns also grow about air pollution, acid rain, and other environmental problems. This study shows that over the next 20 years the United States has the ability to increase its annual use of natural gas by approximately one-third. If it does so, the nation and the world stand to be cleaner, more secure against potential energy supply problems, and better off economically.

The challenge to the new administration and Congress is that at this moment our country is not headed in a direction that makes this *possible*.

As things stand, neither the U.S. supply nor demand for natural gas would grow rapidly enough to do what political leaders, environmentalists, economists, energy analysts, and academics now agree should be done. But conditions can change and be changed . . . and this report suggests how a new national attitude about natural gas can be helped along.

Both presidential candidates in the 1988 election backed the broader future use of natural gas. Now that the election is over, attention must focus on "how we can get from here to there." "Here" is the still-conventional wisdom in energy circles that U.S. use of natural gas for the year 2010 is likely to be at virtually the same level as today's if present trends persist. "There" means a much enlarged consumption of natural gas, especially at the expense of imported oil.

In this study we asked a number of questions about the future of natural gas. First, we tried to discern whether there was any way natural gas could fill the larger role assigned to it by both sides during the campaign. Then we pressed on with the hard question of whether the nation would really benefit if it did. Our conclusions are positive on both points. Natural gas can play a bigger role, but is not a panacea; and its increased use is an indispensable factor in the kind of mixed-and-balanced energy equation that best suits the nation.

As the study progressed, it focused on *means*. We asked what was needed to change the results of the model projection of gas use by the WEFA Group from a modest growth scenario of "business as usual" to an accelerated growth scenario in a "new gas environment" (with worthwhile effects on energy security, national productivity/

A Précis

competitiveness, and environmental quality). Surprisingly little, we learned . . . if supply and demand are *both* addressed.

Government and private-sector analysts should be especially interested in the *sorts* of assumptions about continuations or modifications to national energy policies that have been made here to test their combined effects. One set of mutually reinforcing actions by the federal government is outlined broadly on page 5 and amplified thereafter in the text. Individually, none of these steps may be terribly surprising to students or implementers of energy policy; but the fact that they are parts of an integrated approach is critical.

This is not to style our mix of policy options as a "take it or leave it" recipe. The fact is that natural gas is not a *perfect* fuel for all locations and economic sectors; nor is it one that can stand alone. A different mix could achieve similar results. But natural gas *can* play a larger role, and a mix of new policies can make a significant difference in energy security and the quality of our environment. Any combination of governmental choices in the real world involves trade-offs, and both the President and Congress could fine-tune a set of proposals such as these in a way that U.S. consumers and producers of energy will find to their satisfaction.

From a practical political standpoint, it is hoped that this report can constitute a reasonable framework for discussion in the weeks and months to come. Wherever possible, the potential costs and benefits of various courses of action are at least summarized, and the far more compre-

hensive reports generated by individual participants in the study will be available to those who can profit from their detail.

It also became clear in the course of this study that new initiatives in natural gas policies alone would not do enough. Other vigorous policies to encourage domestic energy sources and to foster conservation are essential if the nation decides to slow the rise in oil imports from insecure sources while preserving a healthy economy and environment. These include policies to stimulate domestic oil production, promote the introduction of clean-coal technologies, seek further safe and economic development of nuclear-based electricity, use "renewables" to the maximum practical extent, encourage more efficiency in energy applications, and support basic research on promising energy technologies for the longer term.

We have not drafted this as a contentious document, but as a consensual one—with interesting and valuable results. For instance, some readers may be amazed that the following pages do not dwell on such long-debated questions as open access to gas pipelines. Yet the gas industry itself is not of a single mind about some such issues—let alone suggesting that all regions of the country or all categories of consumers might reach agreement on them. Not one of the policy options that is mentioned here is likely to be considered radical. All are based on cautious study and free exchange among experienced observers who have served Republican and Democratic administrations or who have worked in one segment or another of the natural gas industry over the past several years. Each has been asked to

concentrate on findings and issues that can unite them.

The starting point of our study (and of this summary report) was a projection of patterns in U.S. energy demand for the year 2010. This baseline projection anticipated that technology and economics will continue to make the nation more efficient in applying energy resources—so that full-sized passenger cars in 2010 might routinely deliver about 50 percent more miles to the gallon than they do now, and each dollar of real gross national product (GNP) would be associated with the consumption of about 30 percent less raw energy in any form (moving well beyond all the conservation measures of the 1970s and 1980s). Furthermore, the base-case model was cautious in assuming a fairly modest rate of economic growth (an overall average of 2.5 percent per year); and it counts on the completion, licensing, and operation of nearly all commercial nuclear powerplants now under construction. Other modeling assumptions and approaches are reported far more fully in a separate publication.

The contrast between this base case (which foresees U.S. use in 2010 of natural gas that is equivalent to about 9 million barrels of oil per day) and the much higher supply-and-demand that the analysis shows resulting from the enumerated policy options (equivalent to roughly 12 million barrels per day) is striking.

These two hypothetical "cases" are presented graphically on the next page. Neither is a *prediction*; there are always enough imponderables to make long-term prophecy a fool's game. But the projection method is clear and open to inspection. The potential differences between these two prospects arise essentially from a few concerted "mid-course corrections" in federal energy policy. We are convinced that options of this type deserve examination *now*.

The bulk of this report asks a series of questions . . . and provides considered, cogent answers:

Where can all that gas come from? . . .
and how is it to be delivered? Page 6

How and where can natural gas fit in?
. . . and how soon? Page 16

What does gas "buy" us in terms of energy
security? . . . and at what cost? Page 25

How much can natural gas do for
environmental quality? Page 29

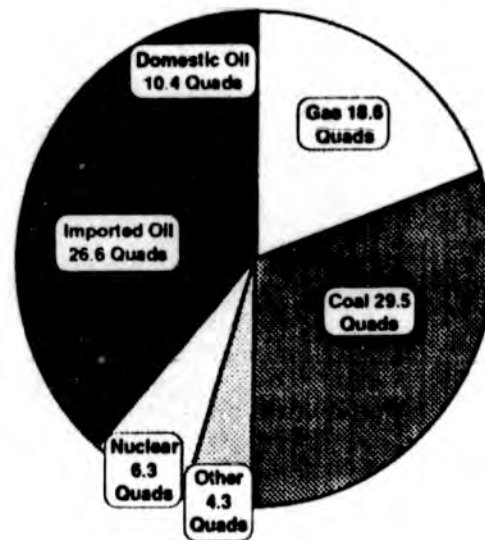
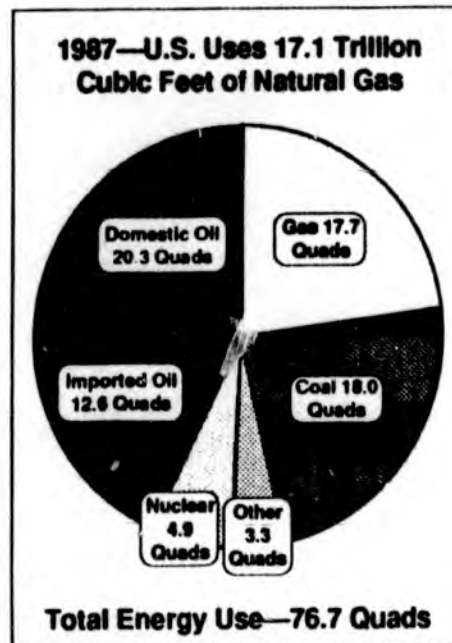
What are the implications for budget,
overall growth, and international
affairs? Page 34

*The difference between this projection,
based on "conventional wisdom" . . .*

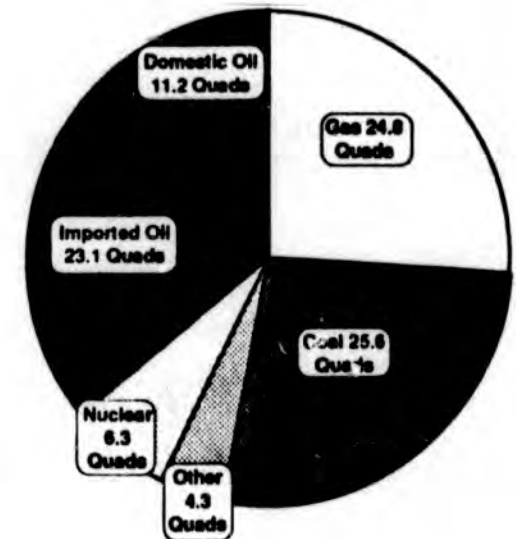
*. . . and this one, based on
"a new environment for gas" . . .*

**2010—U.S. Uses 18.2 Trillion Cubic Feet
of Natural Gas**

**2010—U.S. Uses 24.1 Trillion Cubic Feet
of Natural Gas**



Total Energy Use—95.7 Quads



Total Energy Use—95.3 Quads

... came from certain budget-conscious assumptions about federal attitudes toward:

A "least-cost" strategy to achieve desired environmental standards

- Basing enforcement on *performance* rather than mandating specific control *techniques* (thus favoring such low-cost methods as trading emission "credits" and burning gas in conjunction with other fuels, in preference to coal "scrubbers").
- Monitoring compliance in terms of areawide "bubbles" rather than individual facilities (thus encouraging the selective, cost-effective replacement of older equipment).
- Assisting local efforts to clean up air pollution by specifying that federal funds for public transport fleets (for example, from the Urban Mass Transit Administration) be used exclusively for low-polluting vehicles.

Targeting of R & D

- Research and development on the geoscience that underlies natural gas production.
- Federal funding and other incentives for R & D associated with gas-use technologies—including advanced combustion turbines for generating electricity, cooling by gas, vehicles, and the "co-firing" of gas with other fuels.

Improvements in the "deliverability" of gas

- Use of all responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to regions that are now heavily dependent on imported oil.
- Encouraging adequate storage of natural gas in the context of an emerging new supply-and-demand context.

Incentives to exploration and production

- Prompt identification and lease of the most promising federal lands where exploration can be deemed environmentally acceptable.
- Limited tax credits (for example, 10 percent for all exploratory drilling activity, plus 10 percent for redevelopment drilling in old fields with newly recognized additional potential).
- Adjustment of federal royalties to permit earlier recovery of investment in productive wells . . . and a sliding time-scale of royalty collections, based on market prices (but expanding ultimate return to the Treasury).
- Complete decontrol of wellhead prices for all gas.

Note that some of these policy options apply to basic gas supply for the nation, others apply to the demand side of the market equation, and a couple relate to both supply and demand. Each is described—with its "upside" and "downside"—in the text of this report and supporting publications.

Wherever possible, the effects of individual actions were factored into supply and demand estimates—although some are obviously difficult to quantify. It is clear that various elements of an entire program (this nominal one, or any other) *interact* to produce a cumulative result that can surpass the sum of its parts—so that concurrent action on *all* fronts is desirable if not essential.

Where can all that gas come from? ... and how is it to be delivered?

**The United States Has
More Producible Gas
Than Most People Thought**

There is no doubt now that enough natural gas *can* be produced and delivered from secure sources at reasonable prices to let gas serve this country as an important "bridging fuel" to 2010—by which time even more-environment-friendly renewable sources might be nearly ready for widespread and economical use.

This represents a major turnaround in outlook. As recently as five years ago, the carefully prepared biennial *Projections* volume of the Department of Energy (DOE) went virtually unchallenged in asserting that new U.S. gas reserves were dwindling fast and that conventional production was likely "to decline at 2 to 5 percent per year from 1990 to 2010." Yet resource estimates made earlier this year by both DOE and the industry's Potential Gas Committee (PGC) agreed that there is enough gas left in the ground for today's technology to continue pumping it out economically at present rates for at least 35 years. An additional decade of supply awaits us in gas that could be recovered if prices at the wellhead rise modestly in the future to the equivalent of between \$3 and \$5 per thousand cubic feet (Mcf)—in other words, the counterpart in energy content of oil at roughly \$20 to \$30 per barrel today. Furthermore, even this fails to take into account future supplies of "unconventional" gas—the sort that budding technology might

derive from sources such as coal seams and shale formations. Their development could extend the total available resources by another one-quarter to one-third.

What caused this fresh optimism about domestic supply? No new giant gas fields were discovered (although Mobile Bay and deep waters of the Gulf of Mexico show great promise). In fact, lower world prices for oil have drastically reduced U.S. exploratory drilling over the past three years—although the nation's *production* of natural gas has defied the gloomiest predictions and headed back up again. One reason for rising confidence about gas resources is that a better understanding of geology shows how irregular underground reservoirs of gas are—revealing that closer and better spacing of wells makes it possible to drain fields much more efficiently, even when only the conventional production methods are employed.

A knowledge-jump of this nature is hardly unprecedented. The internal combustion engine nearly lost the U.S. automotive market to steam-cars and electric vehicles early in this century, because gasoline supplies were feared to be inadequate—until new ideas about where petroleum existed led to finding the huge Spindletop Field. Shortly after World War I the domestic outlook for hydrocarbon resources was bleak again—until advances in geophysical surveying and

production brought about development of previously unexpected new fields in West Texas. The long-term value of broadening continually our understanding of geoscience cannot be disputed.

The new DOE study gives a series of specific examples—along the Gulf Coast, in South Texas, and encompassing parts of Kansas and Oklahoma—where fields that had been abandoned or were assumed to be nearing total depletion are now diagnosed as holding up to 25 percent more gas than was estimated initially—in untapped reservoir compartments that simply are unconnected to those drained earlier. Apparently this holds true for many of the 10,000 fields the panel evaluated nationally. Much of the additional gas can be located and drawn off merely by sinking new wells between the old ones . . . and by putting wells closer together as new fields are opened up and old ones are extended.

Obviously, that process can be made far more efficient through geoscience research if it becomes possible to target such heterogeneous reservoirs more accurately (for example, through high-resolution seismic imaging) and to contact more of the gas-bearing rock (for instance, through advances in horizontal drilling). In many fields, older wells can now be reevaluated with technologies that were not available when these wells were drilled 10 to 40 years ago—with even newer methods in the testing stage that will make this process much more efficient in the 1990s. It should be possible to locate and reach gas resources that were bypassed initially but can now be connected to existing pipelines as deeper reservoirs are depleted.

The pattern of new gas discoveries in the United States has changed a couple of times over the history of the industry. Nearly half of all the 390,000 U.S. wells that have ever been drilled have been sunk since the mid-1970s; but the average addition to gas reserves *per well* dropped suddenly at that time to only about one-quarter of what it had been since 1900. The heartening news is that well output has held remarkably steady at this new plateau; and Professor William L. Fisher, of the University of Texas at Austin, offers convincing analyses to support the expectation that it will remain so through the next 300,000 completions. The gist of his interpretation is that few "elephant" fields remain to be found (with the possible exception of offshore—where the average well now produces 7 times as much as the national average in reserve additions—and in largely untapped Alaska). But there are many more small and moderately sized reserve pockets than had been recognized, and advanced technology has increased the success rate in locating them.

In our judgment—bolstered by discussions across the industry as well as with academics—modest tax incentives probably would trigger considerable additional investment in both exploratory drilling and "redevelopment" of old fields. For purposes of modeling, we tried to gauge the effects of a 10-percent tax credit in each case. In the case of redevelopment for older fields that are past exploitation by conventional means alone, "qualifying" fields might be limited to those beyond a certain age relative to discovery and "full" development and those whose annual production

**Secure Sources Include
Some Gas Beyond the Borders
of "The Lower 48"**

showed clear decline over a five-year period such as 1978-82 (before market conditions prescribed the curtailment of production for economic reasons apart from resource depletion).

In the scenario for accelerated gas production and use, it is estimated that annual conventional domestic output (exclusive of Alaska) can actually increase by about 2 tcf—including a rising contribution from "tight sand" deposits. Also, unconventional production is projected to become more economically sound as energy prices rise in response to tightening petroleum markets around the world during the 1990s and geoscience leads to advanced production technologies.

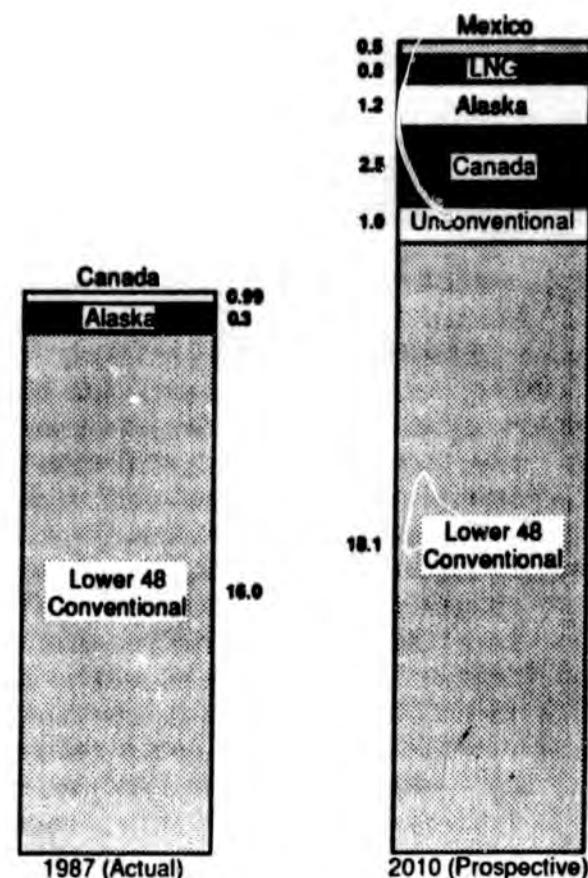
This means that domestic wells in the "Lower 48" can remain the backbone of national supply for decades to come. But there are four other sources of natural gas we should also be able to count on in a projected total of 24.1 tcf annually by 2010—Canada, Alaska, Mexico, and some imports in the form of liquefied natural gas (LNG).

Canada: In 1987 the United States was already importing more than a trillion cubic feet of natural gas each year from its good neighbor to the north. Preliminary data show that this level may climb by another 25 percent this year; and the interrelated dynamics of Canadian reserves, pricing, and pipeline capacity suggest that our net imports from Canada might hit 1.5 tcf as soon as 1990. This would leave ample time in which to develop the delivery infrastructure and market to support a 2.5-tcf annual import flow by 2010.

Closer trade relations with Canada are mutually beneficial in energy. For Canada, the gas sales envisioned would create the incentive and

the opportunity to develop frontier resources that would increase its reserve base dramatically in years to come. In return, this country can foresee a secure supplement to domestic production at competitive prices.

Sources of Cost-Competitive U.S. Gas
(trillions of cubic feet)



Alaska: Alaskan gas resources are substantial—with the known reserves of 26 tcf on the North Slope alone far exceeding a full year's supply for the entire country; but these have barely been developed because markets are so distant. The sparsely populated state is self-sufficient in satisfying its own present demand, of course; but this amounts to only about 300 billion cubic feet (bcf) per year. Another 50 bcf annually is being converted into liquefied natural gas for shipment via refrigerated tanker to Japan.

Under appropriate market conditions (that is, when the real price of gas approaches today's equivalent of \$4.00 per Mcf and looks as if it is likely to stay at that level or higher, while substantial demand exists for gas as a substitute for oil), Alaska could become a significant supplier by pipeline to the Lower 48. Precise timing is difficult to forecast, but it is reasonable to conjecture that a suitable pipeline could go into service within the first decade of the 21st century. This was one of the assumptions used in projecting supply to support the "accelerated U.S. gas-use scenario" highlighted on pages 4 and 5.

Mexico: Large gas imports from the south were close to becoming a reality more than a decade ago; but then progress toward a bilateral agreement ended abruptly and Mexico decided to focus first on developing more domestic applications for its gaseous fuel. A new U.S. administration that has expressed its goal of improving political and economic ties between the two countries should have ample opportunity to revive the project during the 1990s; and those international imports by pipeline could easily begin by the turn of the century—rising to perhaps 500 billion cubic feet by 2010.

Mexico's proved reserves of gas are nearly 40 percent as large as those in this country (76 versus 192 tcf), although its total resources (about 200 tcf) are only about one-fifth those of the United States. Because Mexico's annual domestic consumption is still only about 1.25 tcf, however, vigorous growth in our country's demand could well prove attractive to a market of common value.

LNG Tankers: Norway, Algeria, and Nigeria are all possibly reliable suppliers to the United States once trade in liquefied natural gas to this country starts up again—perhaps by 1990. Development of the North Sea fields in particular has already made natural gas more promising as a European fuel, but it has also brought into the spotlight vast additional reserves of gas that ought to be co-produced while North Sea oil is being tapped. At the same time, unused LNG tankers are available now at reduced cost.

If adequate demand for gas develops here, there seems to be no question but that LNG will be able to serve certain markets—even now, but certainly in any situation when pipeline capacity from the major producing areas might have difficulty satisfying some regions' demand. By 2010 such shipments were projected in the WEFA model to total 0.8 tcf. However, no additional deep-water U.S. port facilities suitable for receiving LNG were assumed before 2010.

Despite our country's huge hydrocarbon resources—even in the Lower 48—not nearly enough exploratory drilling is under way at present to ensure that these will be converted into "proved reserves" and final production of gas at a rate that could accommodate the accelerated-use

**The Level of Drilling
Is a Separate Issue
From Basic Resources**

schedule postulated by this study. The return to actual and potential producers of oil and gas is currently too small—partly because the price being paid for delivered gas is low, and partly because the combined “take” from royalties, production taxes, and state leases is relatively high (for example, totaling an average of about 44 cents per Mcf at a federal leasehold well off the coast of Louisiana, at a time when the producer is receiving only about \$1.75 in all for each Mcf at the wellhead).

Part of the problem lies in the so-called “gas bubble”—a temporary imbalance between supply and demand that was brought about largely by a coincidence of circumstances: a) rapid price increases in the early 1980s, driven by peculiarities

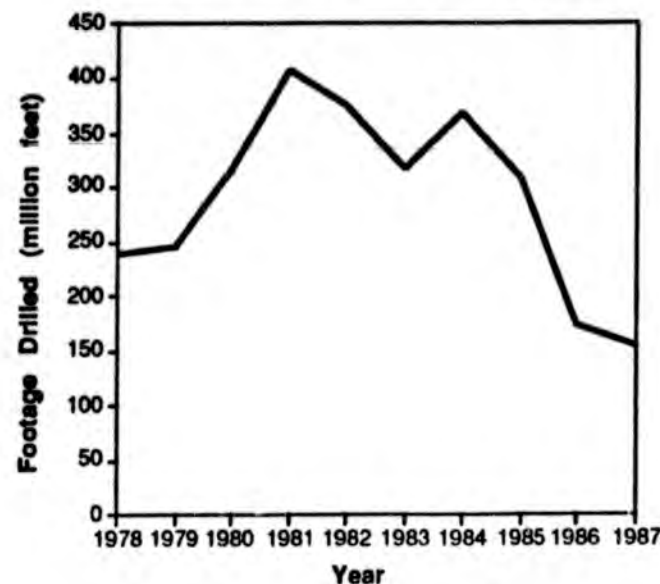
of the Natural Gas Policy Act; b) economic restructuring across the nation, and a general economic downturn in 1982; and c) vigorous energy conservation steps, which dampened demand for all fuels. Most of the experts involved in this particular study believe that it is fading away and should disappear by 1990.

Part of the difficulty also arises from the fact that wellhead prices for some sources of natural gas are still technically under federal regulation—although three-quarters of all gas is effectively deregulated.

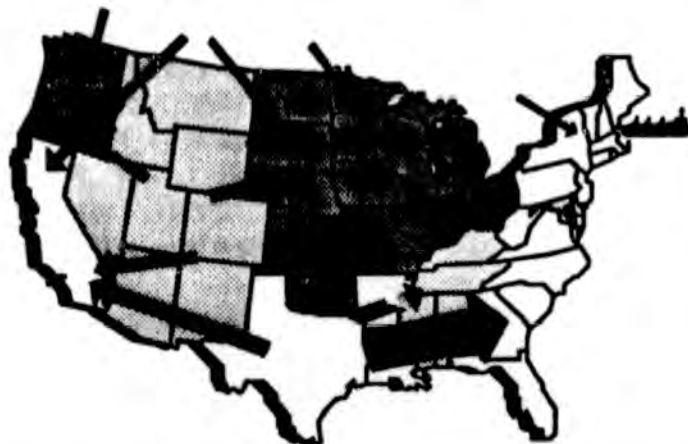
A major contributing factor, however, is the large amount that must be paid out in royalties and taxes as soon as a well enters production. Drilling is a capital-intensive business—and a risky one to boot. The theory behind delaying government royalties and taxes (another policy option assumed in this report) is that faster payoff to an explorer and producer of gas should encourage the search for new reserves and the brisk development of wells that prove successful. Ultimately, this leads to speedier and more efficient application of the nation’s resources. Thus, it also increases government revenue overall.

Some 1.1 million miles of pipeline are used in the United States today to gather, transmit, and distribute natural gas. We know that this network is capable of delivering more than 23 tcf annually as it stands, because the smaller pipe-grid that existed 15 years ago actually handled more than 22 tcf in 1973. Within limits, increased pressure can easily and safely raise the volume of gas being carried over long distances.

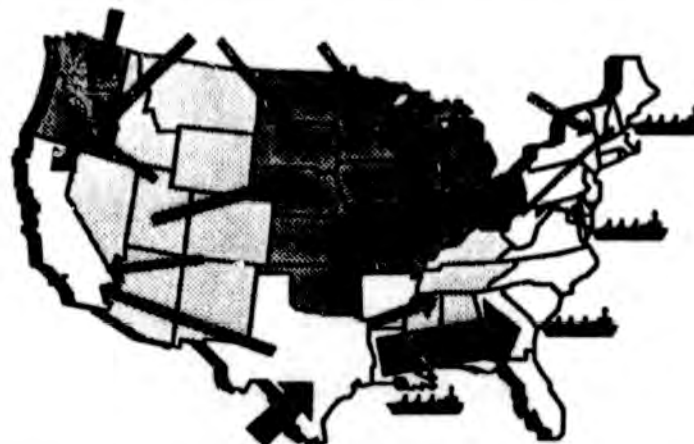
Oil and Gas Well Drilling, 1978-1987



1988 Gas Transmission Patterns



2010 Gas Transmission Patterns



"Packing" the lines is a common practice during periods of high demand (for example, in cold weather, when the requirement for gas heating in residential and commercial buildings soars). Even this could not accommodate the sharp seasonal variations that occur, however; so local distribution companies (LDCs) as well as bulk suppliers have far greater underground storage capacity than the average gas user ever imagines. At the end of October 1986, for instance, the amount of gas in such storage across the United States exceeded 7 tcf. This is the heat-equivalent of far more than a billion barrels of oil—thus representing twice as much energy content as the federal government's massive Strategic Petroleum Reserve (SPR), which was created and is continually being augmented as an emergency safeguard against future disruptions in crude oil supply. And the Energy Information Administration now estimates the industry's *total* storage capacity for natural gas at something above 8 tcf.

But another huge question about the timely delivery of natural gas remains: "Do pipelines carry it to where it will have to go?"

The answer is "No, not completely." A possible breakdown of how the yearly demand for 24 tcf of natural gas might evolve in this country is discussed in the section of this report that begins on page 16; but the two generalized maps above exemplify at a glance how some gas transmission patterns might have to change. Although most gas in 2010 will come from the same geographic regions as it does now, the Mountain States should be a more significant domestic supplier. Alaskan gas ought to be available by pipeline, and perhaps half a tcf of Mexican gas may be in the U.S. supply picture. LNG should be arriving from overseas. Such knotty questions as how future air quality standards will be specified leave the *exact* pipeline needs unpredictable from the distance of a couple of decades.

**Spare Pipeline Capacity,
New Routes, and Storage
Fit Into the Mosaic**

When everything else is equal, history has shown that the demand for natural gas goes hand in hand with its availability. Gaseous fuel was used sparingly by population centers along most of the Atlantic Seaboard through World War II, when it was still being *synthesized* primarily in local "gas works." Once the big wartime pipeline for oil called "Big Inch" was converted to deliver *natural* gas from producing areas in the south, however, both the means of applying it and its total consumption expanded impressively. Even now, the populations of Louisiana and Maryland are almost identical in size; but the first of these two states (in the midst of gas-producing country) uses more than nine times as much gaseous fuel as the latter (where transport costs are higher).

If the Northeast (which is still heavily dependent on oil) wishes to substitute more gas, hundreds of miles of new pipeline will have to be installed. In fact, the Federal Energy Regulatory Commission (FERC) has recently granted construction permits for about a dozen additional gas-transport facilities for that area, and these will boost receiving capacity there by nearly 25 percent.

Unfortunately, potentially avoidable regulatory delays in the permit-granting process have been one of the chief constraints on the expansion of gas markets. Recently, FERC speeded up its own activity by declaring an "open season" for Northeast projects, during which a number of similar or related applications that have been stacking up can be considered simultaneously. Still, federal regulators have not shown enough scheduling and coordinating discipline thus far to produce appropriate speed in licensing pipelines into heavily oil-dependent regions.

Federal initiatives alone might not break the logjam completely, because state public utility commissions (PUCs) and other authorities below the national level are usually also required to grant permission in advance for such construction. Nevertheless, Congress and the administration can set an important example if the consensus emerges, regionally and nationwide, to boost the possible use of gas on environmental, economic, and security grounds.

It would have been far beyond the scope of this study (as well as presumptuous) to try to draft either legislation or administrative rules to facilitate the building of new pipelines where needed. The policy option we have surfaced in this regard needs detail work. Still, we feel confident in offering some general guidelines, which were observed in our modeling effort: 1) Whatever new steps are taken should be responsible ones from the standpoint of environmental protection. This was an easy stricture to accept, because once underground pipelines are in place they do not represent either an unacceptable threat to public safety or any insult to aesthetics. 2) Special consideration might well be given to applications for new pipelines that can serve areas that are heavily dependent now on other fuels, for which the substitution of gas offers demonstrable benefits. A similar case can be made for regions in which dangerously shrinking reserve margins for electricity-generating capacity point to gas-fired turbines as the most practical and timely solution. On both counts, the policy envisioned appears to be fundamental in permitting supply and demand to grow in tandem—as they must.

Additional gas storage, mentioned earlier as a possible insurance system to protect against future global oil supply problems, is also a means in itself to expand current domestic supply. Producing wells churn out gas continuously, and pipelines will have to be filled as much as possible on a year-round basis if they are to render maximum service. Yet demand is bound to remain seasonal to some extent. An even more comprehensive storage system—decentralized so as to offer maximum flexibility—can “level the load,” much as pumped-storage reservoirs do for generators of electricity. With either energy source, this approach makes possible maximum delivery of the product in the most economical way.

It cannot be repeated often enough that supply and demand interact. So do a number of the government policies addressed in this report—especially in regard to bringing the United States’ secure supply of natural gas to the level discussed by 2010.

Today’s clearer understanding of the heterogeneous nature of underground gas reservoirs means that U.S. *production potential* has increased. Thus, the producible domestic *resources* of natural gas (the total amount we may reasonably count on drawing from the earth ultimately, using specific technology and confining production costs to certain levels) are larger than was thought previously. But the fact persists that too little is being done right now to *pinpoint* new reserves so they can be brought to the surface. Unless there is a turnaround, the level of reserves will begin to erode again next year . . . and in the years to follow.

No single, simple solution to the dilemma appears to exist. Instead, a variety of *coordinated* actions came to mind in devising a model that might take full account of the new national attitude toward gas.

Companies in the U.S. gas industry, large and small, are more likely to step up exploratory drilling once again if they have somewhat greater assurance that the fruits of their investment will be marketable at returns that are based on risk and *true* value of the commodity—rather than on oil-price manipulations by an international quasi-cartel or on gas-price ceilings imposed by their own government. Deregulation of wellhead prices is important; and limited tax incentives (only for exploration or for redevelopment drilling in older fields that now stand to be rejuvenated) appear to be needed as well—because of justifiable fears that OPEC behavior can force world energy prices *down* capriciously as well as *up*.

Perhaps 35 percent of the gas that remains to be produced by conventional methods in the United States lies in areas under federal jurisdiction. Rather than exclude blocks on the map wholesale on the basis of emotion and political impulse, it seems to make more sense to establish priorities on the basis of the relative likelihood that gas might be found. This may require something of a public education program, because it is not generally understood that *most* exploratory drilling efforts are destined to wind up as “dry holes.” Environmental risks will never be eliminated completely either. Despite these cautions, an intelligent and informed balance needs to be struck between the equally important goals of resource-need and dedication to keeping our land,

Various Policy Steps
Reinforce One Another
In Ensuring Gas Supply

air, and water in good shape. Once it has been established with reasonable confidence that attractive targets exist for environmentally sensitive exploration, development, and production, such areas should be made accessible (through a sound competitive bidding procedure)—so that the private sector can undertake the job.

Although it seems safe to forecast that energy prices will escalate over time, they will almost surely not rise along a smooth curve. New drilling (which has been cited as a key ingredient in increasing future supply) would be likely to increase still more if government royalty payments could be deferred until the initial capital investment in any successful well had been covered. Production certainly would not cease at that point, because profits would continue so long as revenue from the gas was adequate to pay operating costs and a full, *higher* royalty. Analysis shows that this would bring a greater return to the government, so this is not a matter of authorizing subsidies.

Even before drilling begins, the recent hike in resources based on strategic "infill" production shows that research in geoscience can pay large dividends. The federal government has been committed nominally in recent years to support meaningful R & D on energy topics that are basic to resource development; but budget limitations have held actual DOE expenditures in this field to minimal levels. This year, however, the Department began a three-year, \$22.25 million joint research venture with the Gas Research Institute and the State of Texas to develop and demonstrate cost-effective approaches to recovering

additional reserves from conventional gas reservoirs.

More opportunities exist: efficiency in finding and developing a very large number of small-to-medium-sized gas sources is the key to economics—so that a national "reservoir framework" and trustworthy "reservoir models" would operate synergistically with research on high-resolution geophysics and better geostatistical methodologies. Broad R & D on drilling and hydrocarbon-recovery techniques also seem appropriate for cost-sharing.

Once again, the framers of this report recognize that they are clearly not as well equipped as the President and Congress to decide how these requirements compare with other national needs within the strictures of Gramm-Rudman and a clear resolve to limit the deficit. However, it seemed reasonable to assume that an appropriate level to *accomplish* a great deal in programs of this kind might be a total of about \$100 million per year for several years—divided on approximately a 40-60 basis between gas and oil. Laboratory and field research needs to be accompanied by some effort in actual *demonstrations* of development work by joint ventures involving the government—especially when federal support goes beyond basic geoscience to advanced drilling and production techniques.

The long-run payoff to the nation can be great from such relatively minute taxpayer investments as were assumed in this projection, but fresh invention and creative perceptions of nature do not appear overnight. If we are pointing toward the year 2010, fiscal year 1990 will be none too soon to begin.

In the case of natural gas, furthermore, it has already been noted that *availability* is as critical as basic supply. The existence of an adequate delivery network—made safer and more efficient by increased storage capacity—is an additional constituent of an overall national commitment and plan that cannot be overlooked.

The final section of this report examines the respective costs we calculated for all these plan-components—along with their potential benefits, to the extent they could be quantified. Suffice it to say at this point that some program of this overall shape and scope appears to be worth doing.

How and where can natural gas fit in? ... and how soon?

Relative and Absolute Prices For Energy Will Underlie Gas Substitution Patterns

Projecting the exact way in which one-third more natural gas might be used effectively in this country by 2010 is far more complex (and subject to change) than demonstrating that a reliable and reasonable supply to support this level of demand can be developed. However, the model results were encouraging. Clearly, more gas use *can* make economic sense.

The graphics on the following page present one scenario of U.S. energy consumption (among many that could be proposed for the same time frame with equally sound reasoning) in which there is a cost-practical division of about 24 trillion cubic feet of natural gas by use-sector. We believe that market-based forces could bring supply and demand into a healthy balance at this level without the sort of massive interventionist energy policy that foundered in the past (for example, fuel allocations on the demand side, or the Synthetic Fuels Corporation on the supply side).

The degree to which natural gas substitutes in the future for oil (to make U.S. energy supplies more reliable), for coal (to limit air pollution and acid rain), or for any other energy source depends heavily on what the prices of gas will be *to various potential consumers*—especially in comparison with what the same individual, company, or institution would have to pay if another energy source were chosen instead. Such “burner tip” prices for

gas vary appreciably now—not only because of differences in pipeline distance from one part of the country to another, but also because the rates at which gas may be purchased from a regulated utility company by any specific *category* of customer (residential, large or small commercial, industrial, electrical generating utility, and so forth) must be approved by local public utility commissions, whose policies are not uniform.

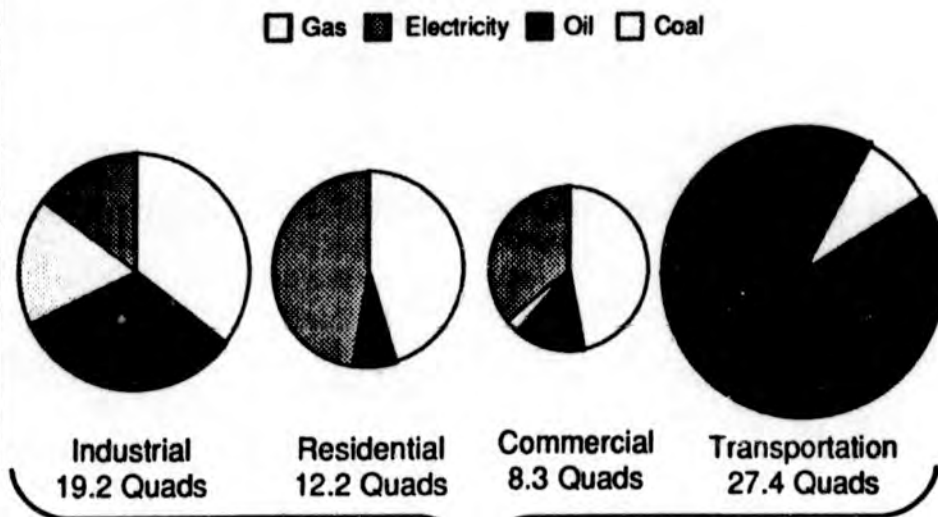
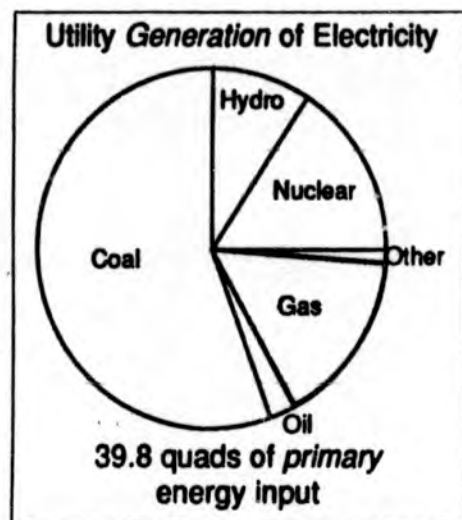
This study accepted the broad consensus opinion that “real” energy prices will rise after a period of relative stability—though not as steeply as was generally suggested a few years ago. We assumed that the average price of oil to U.S. refiners might rise to \$37.50 per barrel in terms of 1988 dollars by 2010. But we estimated that the wellhead price of domestic natural gas would increase at a *faster* rate—to \$4.50 per thousand cubic feet. Coal at the minehead, on the other hand, was pegged at an average of \$34.70 per ton by 2010—not much more than it has been in recent years.

The very substitution of gas for other fuels affects the prices of those other energy sources too, through simple competition. As demand for oil softens, for instance, sellers of the fuel find it more difficult to keep the price up. To the extent that gas replaces oil, gas thus undercuts its own competitiveness in terms of comparative dollar-cost per Btu (British thermal unit). At the

One Way to Utilize 24.1 tcf of Natural Gas Economically in 2010:



... making these contributions to the respective energy-using sectors of the U.S. economy:



These end-use numbers include heat-equivalent of electricity *as delivered*.

Annual use of a "quad" (one quadrillion British thermal units) = generic equivalent of about half a million barrels of oil/day.

same time, however, more widespread use of natural gas should tend to reduce even further the capital cost of certain types of equipment that employ gas—through the cost-saving mechanism of volume marketing and mass production. And the overall cost of using one fuel in preference to another may depend as much or more on the amortization of equipment as it does on how much it costs to fill the tank.

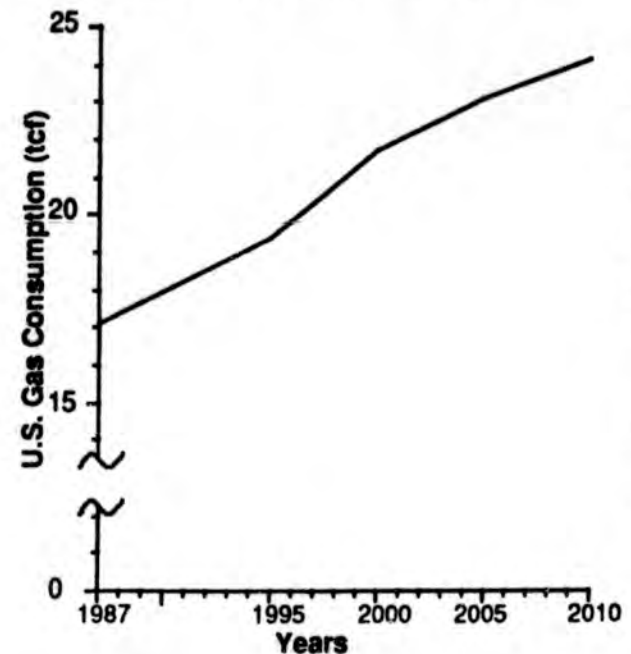
In the case of oil and gas, there is the added complication that both of these fuels sometimes flow from the same well; and the obvious divergences in their price-trends depend on numerous other factors. We tried to consider many of these in the model, but overconcentration on methodology in a summary report of this sort might only obfuscate some of our most important conclusions in regard to potential demand—which are these:

- An overall energy demand for roughly 95 quads was projected in the "accelerated gas use" case for 2010, slightly less than the 96 quads in the "baseline" case. The use of more gas in the roles projected here would tend to reduce the total amount of energy required to provide specified services or maintain a given output—because of greater efficiency in the technologies envisioned (especially combustion turbines). Counteracting this effect is the fact that economic activity would simultaneously be encouraged to rise (based partly on stimulation of the domestic gas and oil industry, and partly on an improved trade balance), drawing the demand for energy upward along with GNP. These "big picture" matters are reviewed in the international

and macroeconomic section that begins on page 34.

- U.S. demand for natural gas might rise in a relatively smooth curve over the next three decades (and, in fact, this is the way it was projected in the computer analysis of our model—as shown on the adjacent graph); but this need not be the case. Judging from historical precedent, demand seems almost as likely to increase in spurts—either as gas-using technologies such as combined-cycle turbine generators, dual-fuel boilers, and

The WEFA Model Projected Gas Use To Increase in this Fashion, But Rises Might Come in Steps



vehicles fueled with compressed natural gas (CNG) are popularized nationwide, or as greater pipeline capacity expands regional markets (most logically, in New England).

- A major force driving the introduction of more natural gas into the U.S. economy in the future could be an effort to meet environmental standards in the most cost-conscious manner. (A section dealing specifically with this starts on page 29.)

In many areas, the local suppliers of gas and electricity have been fierce competitors. To some extent this will continue—particularly where the nascent technology for gas-cooling starts to challenge electric heat pump systems. However, the relationship between the gas and electricity industries overall might be in for some basic changes—as the former becomes a crucially significant supplier to the latter.

For a number of reasons, the demand for electricity is expected to grow more rapidly than the consumption of energy overall. Our assumption was that the growth-ratios of electricity use and total energy use to GNP would be 0.8 and 0.7, respectively, between now and 2010. Nevertheless, the construction of new generating capacity in this country has slowed precipitously. We are frequently reminded that it has been almost 15 years since the order was placed for the last of the nuclear powerplants still being built, but construction of large coal plants has also slowed. The Department of Energy was consciously conservative in its *Energy Security* report nearly two years ago when it warned that at least 100 gigawatts of additional generating capacity appeared to be

necessary by the turn of the century... and hinted graphically that the potential shortfall was likely to widen thereafter. Yet utilities are still loath to place long-lead orders for capital-intensive fresh construction.

Apart from the special advantages of natural gas as an "environmentally benign" heat source for generating electricity, gas turbines inherently are easier and less costly to *build* than steam-generating plants of any sort. For this reason, they offer the best current hope in closing the "capacity gap" as it becomes sufficiently critical to threaten brownouts in certain parts of the country. With all this (and more) as background, we felt confident with a detailed analysis that showed gas supplying nearly one-sixth of the primary energy used in generating electricity by 2010. This alone would require about 6 trillion cubic feet of gas annually, or more than twice as much as is being used now by the electricity industry.

The new transportation role we postulate for gas lies more in a series of pinpoint targets—the so-called "fleet" markets, especially in regions where it will continue to be difficult to meet air-quality standards.

Natural gas has been used on an experimental basis for two different types of vehicles—those that carry cylinders of highly compressed gas as fuel, and those that can substitute methyl alcohol (methanol) for gasoline in somewhat oversized, but more-or-less conventional tanks. Theoretically, methanol can be manufactured from coal or vegetable matter; but it will be a very long time before its unsubsidized production from either of those feedstocks can match the

Industry and Vehicle "Niches"
Complement Generation Market;
Tossup Seen in Cooling

economics of using natural gas as a chemical base. However, in this study we calculated only the effects of employing CNG vehicles on a large scale, because (paradoxically) their proportional demand for natural gas is somewhat smaller than is required in the overall methanol cycle and we wished to be conservative in estimating the potential market for gas in 2010.

Whether CNG or methanol eventually becomes the gas-based fuel of choice as an alternative to oil-based products in road transportation, it will probably enter the market first on a broad scale via specialized vehicles rather than ordinary private autos. An ongoing DOE study has alluded objectively to some of the reasons behind this in the preliminary reports it has issued, but they boil down to the following: the size and weight of tankage (which is easier to accommodate in larger vehicles); greater capital cost (which fleet owners might absorb more readily in anticipation of longer-term benefits); and the need for convenience in having places to refuel while a general distribution network is evolving (something many fleet owners are capable of providing for themselves). It is worth adding that essentially the same ground rules will apply to commercial penetration of the transport market by electric vehicles—which must still be considered prospective competition for gas-based taxis, buses, and local delivery trucks.

The final demand model in this study assumed that no more than one private car in 20 would be using natural gas as its primary energy source by 2010 . . . and that CNG vehicles would constitute only one-quarter of the private fleets in the country. But at the same time it seemed realistic to estimate that 75 percent of all city buses might

have switched to CNG by then. With all else equal, the prospects of reducing local air pollution by this means can obviously have great appeal. And it would be relatively easy for an administration pledged to help preserve environmental integrity to specify that funds provided through the Urban Mass Transit Administration (UMTA) or any other federal agency be used only for less-polluting vehicles—with the exact choice to be left to local authorities.

With these assumptions, we judged through model runs that an extra 1.7 tcf of gas would go into the transport sector for motor vehicles each year by 2010. This would be in addition to 0.6 tcf of gas that would be required to operate pipeline compressors around the nation—a use that is already commonly tabulated in energy-consumption tables as an input to transportation.

The other big new "niche" markets that we could foresee for natural gas are in industry. Even a cursory examination of construction filings for cogeneration facilities suggests that gas is the most favored of all fuels for this process—in which the end-results are both usable heat and electricity. Furthermore, the secular trend nationally toward a less energy-intensive service economy might combine with improvements in efficiency to slow down industrial consumption of energy in general; but a combination of economic, security, and environmental considerations should make gas a stronger contender for industrial use in general.

Residential consumption shows less opportunity for gas-demand growth overall. Despite regional limitations now, gas is already supplying heat to more than 45 million of the nation's 88 million dwelling-units. In addition,

approximately 34 million American homes also use gas now for cooking. Although new home customers for natural gas will appear in some areas where they have been rare, many will be able to achieve the same results in the future by expending less energy of any sort. Improvements in the efficiency of gas furnaces, coupled with slow but continuing improvement in the average insulation of our housing stock, will tend to cut the gas requirements per residence. Microwave ovens and electric heat pumps also compete with gas (although gas-fired heat pumps have been under development for years and might make a dent in the future).

The biggest imponderable in future commercial gas demand will be space cooling. Much of the rapid increase in use of electricity during recent years (especially at seasonal peaks) has been for air conditioning; but the contest between gas and electricity in this arena is not over. Double-absorption cooling by gas is ready to pose a major challenge—as are very efficient engine-driven gas “chillers”; and this potential was factored into the various demand scenarios we considered. Again, however, we were conservative—assuming merely that targeted R & D could help gas to increase its share of the commercial cooling market from its current 6 percent to a still-modest 10 percent between the 1990s and 2010.

If this country increases its emphasis on natural gas, the actual fuel substitution that takes place will depend on the sectors in which switching or replacement goes on. That is one reason

why this study took such pains in dissecting potential demand growth.

In the scenario pictured on page 17, the nation would use approximately a million and a half barrels of oil per day less by 2010 than in the baseline case (although imports would be affected more than that because of a 600,000-barrel-per-day stimulus to domestic production). Slightly more than half of the oil replacement would be in motor vehicles, and most of the rest would be divided between industrial and electric generation markets. However, generators of electricity have already slashed their dependence on oil—relying on it for only a few percent of their total energy input in recent years (even after the price of oil plummeted in 1986). The baseline model for 2010 projected little oil left in that sector for gas to replace, but gas in combustion turbines would be substituting for some oil as well as coal. This fuel-switch would be dictated by economics, but only because the partial use of gas (either on a seasonal basis, in “co-firing” with coal, or both) is quite likely to be the most cost-effective way to meet environmental standards.

The prospect of using more natural gas for generating electricity does not eliminate the importance of pressing ahead vigorously in the United States with coal production or with R & D on more economical clean-coal technology. Even with the accelerated gas use we have projected for 2010, this country would be using approximately one-third more coal than it does now. With domestic consumption around 1.2 billion tons annually by then, export markets can be envisioned that might coax U.S. production into

**Natural Gas Could Replace
About 1.5 MMBD of Oil More
... And Augment Clean Coal**

**Role of Gas In 1990s
Might Switch Emphasis
In Years That Follow**

approaching a billion and a half tons. Because the national insistence on air quality is not expected to evaporate, better ways must be found to burn even high-sulfur coal acceptably. Mandating the use of "scrubbers" raises new environmental problems in itself (besides reducing efficiency and ballooning costs); but such technologies as fluidized-bed combustion hold out more hope.

The principal opportunity to expand gas use during the next decade is in supplying electricity.

There are relatively few days during the year when low "reserve margins" of generating capacity pose their most serious danger—and then only during the hours when customers' demand for power rises to a peak. Because air conditioning has such a voracious appetite for energy, the public tends to associate such problem periods with high summer; but the widespread use of electric heating in an area like the blustery Northwest makes for "winter-peaking" utilities there . . . and the popularity of electric heat pumps in the Mid-Atlantic States is moving their generation load-curves into a characteristic shape that has twin peaks—one in cold weather and one in hot.

Conventional turbine-generators fueled with natural gas have been used for some time as "peaking units"—expressly to meet occasionally very large demand. In this role, their relatively high fuel cost per kilowatt-hour (as compared with "baseload" steam-turbine plants) has not been too limiting. Nor has the fact that many of today's gas turbines might face technological problems if they were forced to operate continu-

ously on a year-round basis instead of serving for intermittent spells as needed.

The maximum electrical output of the largest "combustion turbines" (so-called because the high-temperature combustion gases themselves spin the turbine blades) is fairly small in relation to the customary baseload plant. This can be an advantage in an era of fiscal caution in meeting demand projections, however, because it means that capacity can be added in smaller steps. Because these turbines can be ordered from production lines with only a low capital investment, we expect them to be the quick choice of many utilities to protect safe margins of reserve capacity that are threatened during the 1990s.

Gas can also be burned under conventional steam boilers to generate electricity; and, in areas near producing fields, such systems can clearly be economical for base loads. But until the Powerplant and Industrial Fuel Use Act (FUA) was repealed in 1988, it had actually been against the law for years to build utility or industrial boilers using gas as a heat source. This outmoded restriction was motivated by the common view in the 1970s (since proved incorrect) that our country was on the verge of exhausting its domestic resources of hydrocarbon fuel completely. Elimination of the ban forms part of the "new environment for gas."

Combustion turbines are starting to play a different role too. Despite FUA, new gas turbines have been permitted . . . and, in fact, they have even been encouraged (in a way that may not have been foreseen by legislators) through the Public Utility Regulatory Policies Act of 1978 (PURPA).

One of the purposes of this act is to promote cogeneration (albeit outside the electric utility industry), but roughly half of the heat-and-electricity systems that grew out of the initiative are fueled by gas. And gas turbines have been especially favored because of their low-polluting features and their high *overall* efficiency when exhaust heat is put to use.

It is the efficiency factor that presages eventual use of improved combustion turbines for baseload generation. When exhaust heat from a gas turbine is used to operate an integral *steam*-based generating unit, the "combined cycle" system gets an eye-opening power payoff from its input. About 47 percent of the heat is converted into electricity—compared with efficiencies in the 30s for conventional steam plants.

More R & D might even help baseload layouts of linked combustion turbines fueled by natural gas to become a standard item. At present, their major prospective competition appears to be combined-cycle turbines fueled by gas that is synthesized on-site from coal—an integrated system that has performed well in limited testing. Yet some utilities have already announced plans to install only the turbine segment of such a system at first—which means that natural gas would be the initial fuel, presumably to be displaced only if coal gasifiers offered some recognizable advantage.

We can easily foresee gas demand in the United States growing in discrete stages over the next 30 years—with baseload generation gradually superseding gas peaking units in emphasis within certain areas, and the number of vehicles

based on natural gas fuel starting to grow sharply later on.

History has shown that market competition generally results in better products. Consumer choice is not inevitably based on price alone, but can accommodate a remarkable variety of divergent goals—based on individual perceptions of needs.

America's energy requirements for the future involve security of supply, convenience, and the preservation of a safe, healthy, wholesome environment. Natural gas certainly can do more than "conventional wisdom" now says it is likely to do in satisfying energy needs across the board; but we believe that it would be a mistake to order—or simply subsidize—gas use. Therefore we have assumed in our modeling that free choice among fuels (or ways of using specific fuels) will be allowed to prevail. City bus systems would decide for themselves whether the low-polluting vehicles they buy with UMTA money should use CNG, methanol, chemical batteries, or some sort of exhaust-collection devices. Building owners would certainly choose on their own between cooling by electricity or gas. Those who generate electricity (for their own use or for sale) would not be *directed* to use scrubbers as the only allowable method of controlling emission levels—any more than they would be *forbidden* to use any particular fuel (even oil).

The only purpose in targeting R & D (largely through cooperative ventures with the private sector) toward certain *gas*-using technologies would be to make sure that certain useful and

**Policy Recommendations
Stress Broader Choice,
But Let Users Decide**

practical options we can now envision will be available *in time to make a difference*. The available choices should be broad.

Obviously, the same principle can be applied to an assumption we made about deliverability of gas. More than a century ago, the federal government helped in a number of ways to build railroads where none had ever existed; but today, ironically, the inverse is true for gas pipelines. Far from facilitating the creation of a new transport and storage infrastructure, government has often been the principal impediment—through slow-paced regulatory procedures.

An enormous transmission and distribution network for natural gas already exists; and if potential demand is evident in areas that are not yet being served optimally, we are confident that private capital will be available to finance new pipelines. All the federal government needs to do is to see that *needless* barriers to construction are removed.

The exact way for FERC to expedite its own licensing procedures is up to FERC. We believe that this *can* be accomplished, and we have only assumed that it *will* be. Beyond that, its leadership by example might do wonders in affecting the speed of public utility bodies at the state level. Even if the only step in common were to arrange for state and federal hearings on pipeline construction applications to proceed *concurrently* instead of *consecutively*, we have ample anecdotal evidence that the improvement would be felt almost immediately.

Because of the structure of growing demand, it has been assumed that special consideration in the pipeline approval process might be given at least to regions such as the Northeast—where reliance on imported oil is particularly high and where last year's *Energy Security* report from DOE noted there will be a need for "new power supplies sooner than other areas."

What does gas "buy" us in terms of energy security? ... and at what cost?

By 1993, according to baseline projections, the United States could be importing half of all the oil used here. Given the distribution of oil-producing capacity around the world, this country and its allies probably will have to rely on the tinderbox region of the Middle East for much of that supply. The perils to energy security in that case have been well documented elsewhere; they are undeniable.

If all present policies continue, our baseline model projects that U.S. oil imports by 2010 would be approximately 13 million barrels per day—almost twice as much as ever before in history. Imports would then represent more than 71 percent of total oil consumption. Our modeling for "accelerated gas use" (which is only *one* possible alternative scenario) projected a reduction of almost 2 million barrels per day in those imports. Thus, greater emphasis on gas *can* offer greater security against possible energy disruptions in the future; but perhaps even this will not by itself allow us to breathe freely enough. About 66 percent of our oil use still would be tied to imports, and other policy initiatives probably would be needed. Yet it is hardly arguable that the nation should risk postponing some of the relatively easy and economical steps to facilitate larger use of natural gas, whose imminent contri-

bution to oil-import reductions can be demonstrated. Time is running, even now.

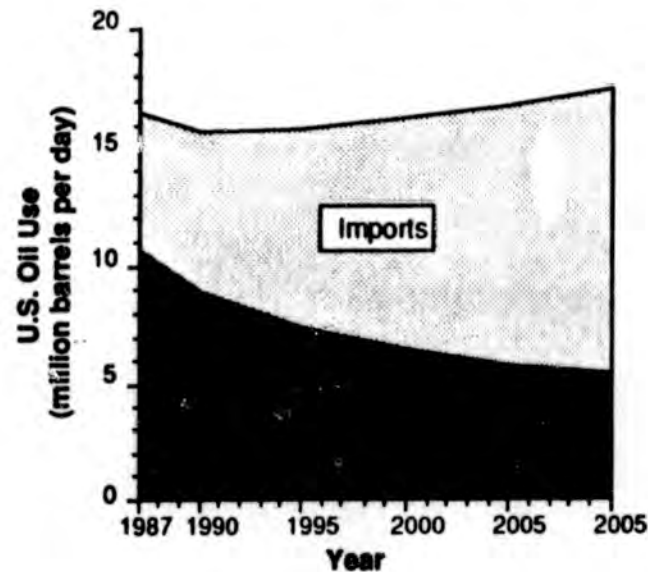
An oil glut exists today on the world market. With prices still low enough to keep our domestic drilling industry at an ebb, it may be hard for the public to focus on the fact that the international community's earlier rollercoaster rides in energy prices and energy supply could be repeated during the 1990s.

Cruel economic lessons of the 1970s have not been forgotten completely. Continued progress in energy efficiency and foreseeable fuel-substitution is expected to reduce oil's *percentage* share of the U.S. energy market. We see oil falling from around 42 percent of all energy consumption now to approximately 39 percent some two decades hence—even in the baseline case. If this seems like an excruciatingly slow pace at which to "back out" the fuel that has been the basis of what once was called "The Energy Crisis," remember that oil accounted for 47 percent of the nation's energy use in 1973. Fairly heroic measures have been taken since then, notably in a consumer revolt that amazed most economists after crude oil prices briefly hovered close to \$40 per barrel. The preceding section of this report gives some inkling of how imaginative and perseverant one must be to replace *additional* oil in an economy of

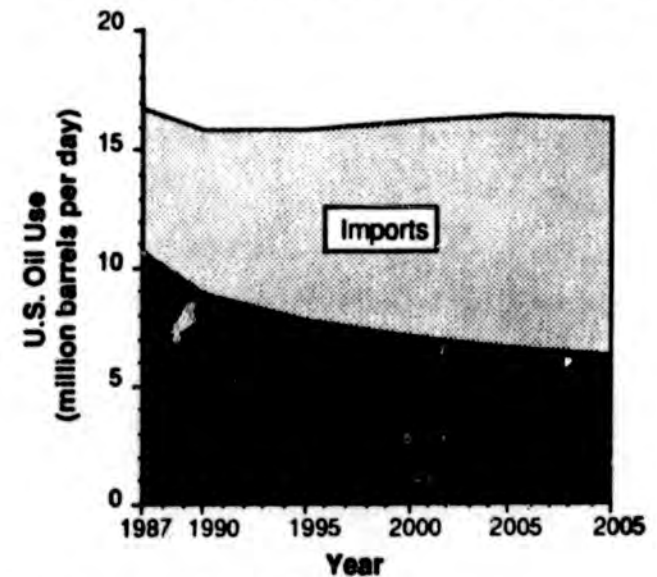
**U.S. May Be Vulnerable
To Energy Pressures
Again Before 2000**

Two Projections of Demand for Oil in the U.S. Economy:

a. following the present course



b. with this report's assumptions about modest moves to accelerate gas supply



Anything that permitted still greater reliance on alternatives to oil (including coal, nuclear power, renewables, and improved efficiency) might lessen imports in an extension to case "b." But additional problems in taking full advantage of such sources as coal and nuclear energy would compel even higher imports.

U.S. size. Almost 6 out of every 10 barrels of oil we use go into transportation—with the greatest portion of that devoted to fueling about 160 million autos and light trucks.

Even with the "oil fraction" on its way down, our growth in population, road fleet, and GNP seems destined to force an increase in the total amount of petroleum products we use. For this

reason, it is important to consider two other ways in which bolstering natural gas production helps to guard against oil problems we can see on the horizon:

- We have already noted that oil and gas are often found in the same geological formations. Intensified exploration for one aids discovery of the other. Part of the cuts in oil

imports we project comes from the growth in domestic oil output that would accompany more emphasis on natural gas.

- Besides producing the "dry" gas that winds up in statistical tables and pipelines, natural gas wells and processing plants are the source of "natural gas liquids" (NGL). These can be used ultimately in place of various products that come principally from the refining of crude oil; and they already underlie about 10 percent of our national supply of such products.

Historically, a great strength of the U.S. economy has been a resource-endowment that was rich in the nation's premier fuel. At first this was wood, and then in the 19th century it switched to coal. For several generations it has been oil. Domestic producers have been much more thorough to date in tapping oil resources than they have been in taking advantage of gas, so production of the latter fuel retains some growth potential while the former will be hard pressed to hold its own. At some time in the 21st century, this nation may complete another energy transition, entering the post-hydrocarbon era. However, our study of renewable-energy technologies has led us to believe that their growth will not be rapid enough to permit them to "take over" the national energy-consumption infrastructure as early as 2010. Meanwhile, it is important to develop resource strategies that can sustain growth and protect both economic security and foreign policy interests.

One of these is already the Strategic Petroleum Reserve. The fact that it has not been called upon

tends to point up its efficacy rather than to diminish the justification for its existence. Surely the 550-million-barrel-plus SPR (and its counterparts in other countries) relieved some apprehensions during the Iran-Iraq War and provided a bit more freedom of action in dealing with threats of oil cutoffs. There was also a time in the recent past when the Organization of Petroleum Exporting Countries (OPEC) was quite successful in its short-term efforts to manipulate prices by mutual agreement among suppliers. The availability of reserve crude oil that could enter the U.S. market during any period of adjustment to an emergency discourages any consortium of suppliers from trying to wield economic power again in a way that is openly hostile to our interests. The same reasoning explains why it is advantageous to develop natural gas supply as an alternative to imported oil (via the possibility of fuel-switching).

The major danger we foresee now lies at some indeterminate point in the future when OPEC has recovered enough of the global market so that approximately 85 percent of its own oil-production capacity is being called upon to satisfy world demand. By an historical rule-of-thumb, this is when such a quasi-cartel is sufficiently emboldened to take drastic actions—raising prices sharply, withholding supply, or a combination of the two in an effort to squeeze maximum rewards for its product from customers who have little other choice.

Even in the "accelerated gas use" case, it may be almost impossible to avoid such a new confrontation forever. On a worldwide scale, our computer projections show OPEC delivering on the order of 35 million barrels of oil per day by 2010—

**Alternatives to Oil
Reduce Cartel Incentives
To Squeeze Down Supply**

fully twice as much as today. But postponing what now appears to be inevitable is not an idle exercise. And the difference in U.S. gas consumption for 1995 between the two cases we present in this report is a hefty 1.5 tcf—the equivalent of some 750,000 barrels of oil per day. Between now and then, the policy options we assumed appear to double the prospective growth for natural gas.

As to dollar costs, this depends on whether they are viewed in a narrow or a broad context... in the long term or the short run. For instance, a 10-percent tax credit for exploration might directly reduce immediate government revenues by about \$350 million annually. But the benefits to the whole economy (not to mention the ultimate increase in federal and state royalties for producing wells on government-controlled lands) would balance this expense within the first three years. This is covered more fully in the section of the report that begins on page 34. But the most important response to questions about the cost of these moves toward greater energy security is that they should, in all fairness, be balanced against other benefits as well (improved trade balances, environmental protection, and so forth). The quest for energy security is not the only reason for this country to swell its supply and

use of natural gas; in some quarters it probably is not even the chief one.

One of the more novel ideas that emerged during our study was a proposal that the nation's program for a Strategic Petroleum Reserve be broadened to include the largely decentralized storage of natural gas as well. Because demand for gas is highly seasonal, the dollar-wise impulse to utilize pipeline capacity to its fullest has led to the creation of a vast number of underground reservoirs—usually quite near consumption centers, but invisible to customers. Given the substitutability of natural gas for oil, we questioned whether it might not be cost-effective for the Department of Energy to lease such space and fill it with purchased gas as an additional buffer against price shocks or supply problems in oil.

Certainly this is one concept on which instant consensus within the gas industry itself is impossible. Producers, transporters, and distributors of gas have differing viewpoints. Like the prickly question of how to settle old "take-or-pay" contracts, the possibility of an SGR was not addressed specifically in our modeling. Yet we raise the notion in this report because we believe it is worth being subjected to further critical analysis.

How much can natural gas do for environmental quality?

Natural gas can do even more for the cause of clean air in this country than some of its proponents say it will. It depends a lot on how conscious we are as a nation of how various types of atmospheric pollution take place.

In coming to grips with the problems of airborne pollutants, there has been too much preoccupation with "percentages" or "tonnages of emission reductions" (often "determined" theoretically), as distinguished from real *results in improved air quality*. Sometimes there has even been a stubborn, counterproductive insistence on specifying the *way* emissions should be curbed.

The nation would be better served if performance standards replaced attempts to dictate compliance technology in environmental-protection efforts associated with the production and use of energy. We assumed such a policy orientation in our model—which paves the way for more use of natural gas and, incidentally, an even greater-than-proportional set of benefits to the environment. We also resolved to dig deeper than the obligatory (but essentially misleading) sort of observation that "the use of so-and-so-much natural gas will reduce the atmospheric burden of sulfur dioxide by so-many tons, as compared with Fuel X."

Most people realize that natural gas is a clean-burning energy source. A table on the following

page shows abstractly how it compares with typical samples of coal and oil. This alone is sufficient to show that environmental improvements will hang in part upon whether gas is being substituted for oil or for coal. However, there are other variables as well. Timing and placement of the fuel-substitutions are equally important in the long run.

Professors James A. Fay and Dan S. Golomb, of the Massachusetts Institute of Technology, have produced an excellent analysis, "Natural Gas and the Environment: Benefits for Air Quality," which is one of several reference documents being circulated in conjunction with this summary report for those who are interested in more detail. Even to treat the topic in brief, however, it seems desirable here to explain five general types of environmental effect that arise in part from burning fuels:

- **Acid Deposition**—which goes beyond the familiar shorthand term ("acid rain") to include snow, hail, dew, and even dry deposits of acids that may be formed in the air from the interaction of sulfur and nitrogen oxide emissions with atmospheric oxidants (including ozone).
- **Ozone at Ground-Level**—which has nothing to do with the potentially dangerous lack of ozone in the upper atmosphere, but

**Environmental Value Depends
On Which Fuels Are Replaced,
When, Where, and How**

Comparative Pollution From Uncontrolled Burning of Gas, Oil, and Coal
(using emissions from gas as the standard)

<i>Pollutant</i>	<i>Gas</i>	<i>Oil</i>	<i>Coal</i>
Sulfur dioxide (SO ₂)	1	1000-3000	3000-8000
Nitrogen oxides (NO _x)	1	2	4.5
Small particles	1	20	250
Carbon monoxide	1	1.5	1.5
Carbon dioxide	1	1.25	1.7
Reactive hydrocarbons	(There are virtually no emissions of this type from natural gas. Emission from oil is about twice that from coal.)		

instead is a problem because *concentrations* of this toxic variant of ordinary oxygen can harm plants and cause respiratory diseases when breathed. Ozone is one of the ingredients of smog. It builds up as sunshine works on nitrogen oxides in the presence of reactive carbon compounds (such as gasoline fumes and partially burned gasoline).

- **Carbon monoxide**—a toxic product of incomplete combustion, especially from vehicles. This gas is one of the precursors of ozone.
- **Particulates**—the tiny bits of matter suspended in the air (including soot, fine ash, and assorted kinds of dust and dirt) that turn clear skies into haze and are linked to various health problems.

- The **"Greenhouse Effect"**—a long-range phenomenon of slowly rising temperatures worldwide under a blanket of some pollutants (based partly on a general increase in fuel-combustion of all kinds) that has attracted broad attention recently.

In some cases the pollution effects are not limited to the immediate vicinity of emissions, and in many cases the adverse effects that have been observed come from more than one pollutant.

"Acid rain" is derived largely from sulfur dioxide (SO₂) and nitrogen oxides (NO_x)—especially in *hot, sunny weather* if oxidants are abundant. In eastern North America, there is a sharp peak in atmospheric acid generation between June and August. Ozone forms when NO_x and

hydrocarbons (HC) react together chemically in *sunlight*—particularly on warm, breezeless days. And most of the visibility-blocking haze from particulates also occurs in *summer*.

Perhaps half of the gas-accumulations that give rise to fears about the greenhouse effect consist of carbon dioxide. To produce a given amount of heat, natural gas emits almost 50 percent less of this compound than coal and 20 to 30 percent less than oil. Furthermore, the higher conversion efficiency of gas-fueled combined-cycle turbines promises an additional advantage when CO₂ emissions are related to output of electricity. However, there is a fair body of scientific opinion that "global warming" could regulate itself in various ways; and the emissions that tend to promote it are not all tied to energy production and use. This may not be as strong or independent a talking point on behalf of gas use as some have assumed.

It is obvious that extra substitution of natural gas for other fuels during the summer months would go most directly to solving many pollution problems that exist. To give a concrete example, a typical 500-megawatt oil-fired powerplant releases some 70,000 tons of sulfur dioxide annually. Replacing oil with gas *for the six months between April and September* (when gas prices drop in many regions anyway) would cut the *annual* output of SO₂ to 35,000 tons; but, because acid formation normally speeds up during those months, the *effect* would be the same as if it had been cut to only about 17,500 tons year-round.

Fortunately, this approach would dovetail with the traditional seasonal lull in U.S. consumption

of gas (which is still used in the residential and commercial sectors primarily for heating). The pipeline network nationwide is less than four-fifths full of gas during summers now—with regional rates of capacity utilization ranging from 51 to 93 percent.

Fay, Golomb, and others have also pointed out another sort of environmental bonus from selective use of gas. Some equipment permits the burning of gas simultaneously with either coal or oil. In such "co-firing," the combustion with gas actually "scavenges" some pollutants that result from burning the other fuel. Some tests showed that substituting gas for only 20 percent of the heat value of coal or oil in an installation reduced NO_x emissions by 60 percent.

In the case of generating plants, replacing coal or oil with natural gas in actual practice appears to be able to reduce the production of sulfur dioxide in almost direct proportion to the percentage of gas used. On balance, replacing half of the heat value of coal that contains 1.2 percent sulfur with gas will lower SO₂ emissions from 2.5 pounds per million Btu's to about 1.2—which happens to be the rate targeted in most "acid rain bills."

Pollution control is a complex process. Its effectiveness usually depends on local circumstances, and its economic rationality almost always does.

A recent examination of several hundred diverse eastern powerplants came to the conclusion that the very same reduction in acid rain that might result from ordering all of them to install flue-gas desulfurization equipment ("scrubbers") would be achieved—at *less cost*—by switching

Selective Substitution Of Natural Gas Offers The Maximum Benefits

**Requiring Air Quality
Results Is Wiser Than
Telling How to Comply**

from the present fuel (either coal or oil) to gas during the summer half-year.

Lest this encourage a move to *order* that approach universally, it should be added hastily that gas-substitution is not always the best answer either. First, the costs of capital investment, fuel, and plant operation must be evaluated for each of many possible options. The older a facility is, the less worthwhile it is to install the prodigiously expensive scrubbers—which are also costly to operate (because of their complexity, the net-power-loss they involve, and the sludgy wastes that may be generated by hundreds of thousands of tons at a single site). But it also costs some money to convert an oil-fired or a coal-burning plant to make it compatible with natural gas—whether this is done by altering the boilers in place or through providing new side-by-side equipment. Adapting the same system to use *either* of two fuels (or both at once) generally lowers heat-conversion efficiency too—although performance often improves when natural gas replaces either coal or oil, while maintenance becomes easier.

Trade-offs among all the competing technologies that might produce acceptable results in air quality (whatever standards are to be maintained) can best be determined by the operator involved. This also explains why the “bubble concept” and trading of “emission credits” make sense when compliance with environmental standards is being monitored. Under the former, an industrial or energy-producing complex is judged on the basis of the total emissions it adds to an area—rather than by evaluating each of its components individually. With “credit trading,” an

entire installation that gains “points” by reducing emissions more sharply than regulations require is permitted to sell certain emission “rights” to a nearby operation when this might enable the second owner to adopt a cost-saving practice that otherwise would be just beyond the stipulated emission limits.

Without question, both principles could be extended to environmental improvements that come from *selective* switches to natural gas. Both promote competition in finding the best *overall* solution to inevitable pollution dilemmas in the future. By contrast, the “conventional wisdom” that underlies energy-use projections like the one we created in this study as a “base case” are blind to reality: The *baseline of emissions* is fated to rise so long as more energy must be produced and consumed in any way.

Stationary sources of pollution (such as powerplants, factories, and other buildings) are not the only contributors to acid rain, ozone buildup, and dirty air. According to the interim report of the National Acid Precipitation Assessment Program issued earlier this year, for instance, more than one-third of the NO_x emissions in this country can be traced to highway vehicles—with other forms of transportation adding another 10 percent. Here once again, a generalized comparison of fuel emissions such as appears in the table on page 30 does not tell the whole story. The latest information about the conversion of gasoline- or diesel-fueled vehicles to compressed natural gas shows that this can *slash* emissions of carbon monoxide and reactive hydrocarbons. Even if widespread use of natural gas vehicles (NGVs) were limited mainly to *fleets* in metropolitan areas, it would at

least give many cities a fighting chance to comply with national ozone standards. As things stand now, Los Angeles fails to meet requirements on ozone-limitation almost daily throughout each summer.

In all, as of June 1988, 341 U.S. counties failed to meet requirements of the Clean Air Act for ozone. Many fell short of compliance in regard to one or more of the other major pollutants in question too: 129 for particulates, 127 for carbon monoxide, 49 for SO_2 , and 4 for NO_x . More urban

areas will soon fall below various legislated lines unless significant new measures are undertaken. *Something must be done!*

Methanol (derived from natural gas) is another vehicular fuel that would reduce some emissions. For instance, its use gives off less NO_x than gasoline does; and with certain engine adjustments it also cuts carbon monoxide. As explained earlier, however, we limited the single composite "model" we present here to CNG conversion only.

What are the implications for budget, overall growth, and international affairs?

**Taken as a Whole
The Program Is Affordable
—Even in Frugal Times**

The first question when any fresh policy surfaces in Washington this year is: "What effect would it have on the budget deficit?" Because we considered this constantly as we built and polished the assumptions for the accelerated-gas-use model that wound up being described in this report, we are able to respond with confidence: "Little net difference in the short run, but with budgetary benefits increasing steadily in future years."

Perhaps the secret to this welcome finding of fiscal responsibility in WEFA's searching computer analysis is that the situation we postulate is not a "program" in the same sense as an effort to accomplish a specific mission in space, or to develop a broad array of synthetic fuels, or (all by itself) to chop oil imports to an absolute minimum. Instead, it is a composite of many, small governmental handholds and nudges that use the leverage of private-sector motivations to progress incrementally toward certain goals that everybody agrees we must seek—cleaner air, less dependence on unreliable oil supplies, a better trade balance, a healthy employment outlook at the national and regional levels, and so on.

The model is comprehensive enough to integrate any results that can be expressed unequivocally in dollars and cents. Obviously there are some pluses and some minuses, as represented

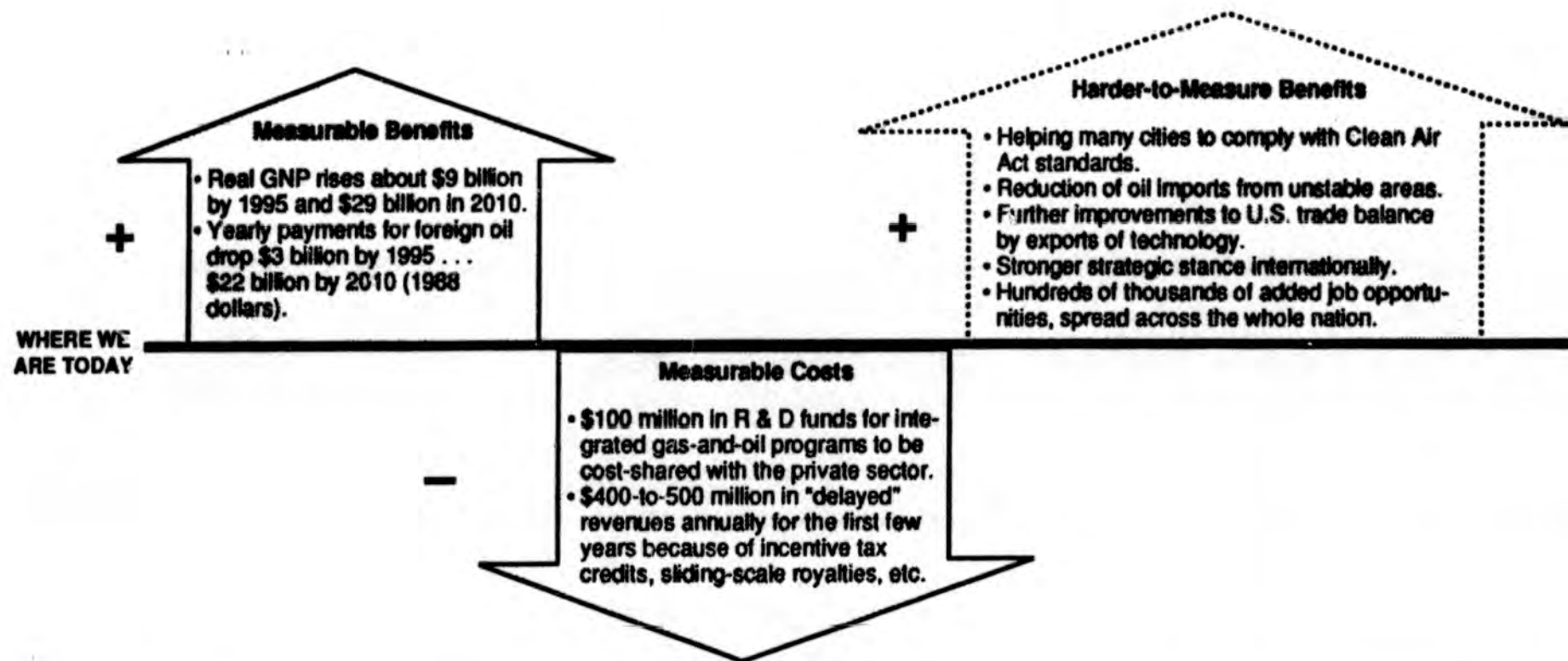
graphically on the opposite page. One implicit factor in the equation, however, consists of benefits whose cash value is real but imprecisely perceived. These are listed in the arrow on the right-hand side.

For instance, if the needed improvements in energy security we enumerated earlier in this report are not achieved by producing and using more natural gas, it is a cinch that their achievement by other means will add costs somewhere else in the budget. The same goes for the nationwide commitment to bring air quality into compliance with the law.

The largest single direct annual cost among the policy options appears to be for tax credits on exploratory and redevelopment drilling. But within two years after enactment of the tax credit the WEFA model indicates that the federal budget deficit would actually be reduced by almost \$1.4 billion because of revenues collected on business activity and wage payments that would not have occurred otherwise. Our analysis on the basis of output-per-well indicates that each additional redevelopment well, involving some \$20,000 in tax credit, would make about a billion cubic feet of additional gas available for production over a 10-15 year period. Such results would clearly stimulate the industry to make continuing investments in the process of recovering "bonus

Generalized Cost/Benefit Balance of the "Accelerated-Gas-Use Case"

(all dollar costs are in 1988 equivalents)



gas" that had been bypassed in older fields because of less complete knowledge earlier about reservoir patterns.

Thus, although a 10-percent tax credit for exploration drilling would be portrayed as an immediate cost to the Treasury of \$350 million through lowered revenues, the program should

actually *enhance* federal revenues in a very short time. Our soundings of the industry confirm the model results, but lead us to doubt that much investment will be made at all on additional exploration and redevelopment in the immediate future (while energy prices remain very low and the demand for gas is "soft") without some such

stimulus. Aside from additional royalties the government would receive in any case where such "new-found" gas is produced from federally controlled well sites, an offset on the positive side would come from increased economic activity throughout the surrounding region. Because many areas suitable for redevelopment drilling are now depressed, the social benefits as well as the economic ones (including greater tax revenue from job-income and supporting business) should be considered when evaluating the proposal.

It ought to be kept in mind always that there is a symbiotic relationship between gas supply and gas demand . . . and among many elements of the policy options in this or any other alternative scenario. Eliminating a single piece of the picture (such as the redevelopment credit) might not destroy the entire image, but it would stand a good chance of distorting it unless another initiative with the same net influence were substituted.

In "big picture" terms, this set of policy assumptions yields strong positive results. Gross national product is bumped upward slightly—from \$6,855 billion to \$6,884 billion (in current dollars) by 2010. The U.S. trade deficit is improved too, even in the shorter run, because of lower oil imports—with the differential amounting to \$1.4 billion in 1995 (in current dollars), and rising to nearly \$24 billion by 2010. By then, the lowering of U.S. demand for imported oil by about 2 million barrels per day would produce some reduction in the world oil price too, providing some economic benefit; but we estimate that this would only amount to pennies per barrel.

The rise in GNP we project is a result of many factors and touches many parts of the economy.

Producing additional steel for an expanded pipeline network, as well as "pipe" and "tubulars" for the oil and gas wells themselves, creates jobs in what has sadly been dubbed the "Rust Belt." Expanding new gas fields where the industry might otherwise be moribund adds work in Appalachia. (Incidentally, the steady rise projected in demand for coal—even though at a lower rate than in the baseline case—shows clearly that this companion energy industry is also likely to have an expanding rather than a contracting payroll overall.) In net total, the additional economic growth was projected to add some 374,000 jobs by 2010.

Productivity and competitiveness are other vital criteria these days, and the more efficient development of U.S. resources in the "accelerated-gas-use case" is among its pluses. It has been estimated that our technology in extracting natural gas from the earth improves by perhaps 2 to 3 percent per year (although this change is masked by larger fluctuations in drilling costs). Thus, even in the base case, we projected that this country would be able to lower its current-reserves-to-current-production (R/P) ratio from 10.2 to 8.2 by 2010. With additional R & D and the entire new environment for natural gas, analysts involved in this study suggest that this ratio could approach 7.0 in the United States, thereby improving production economies.

World reserves of natural gas represent more than 3,600 quads, but less than 2 percent of that base is now being produced annually. Besides the U.S., the six countries that are known to have natural gas reserves of 100 quads or more each are Canada, Iran, Norway, Qatar, Saudi Arabia, and the Soviet Union.

Exports of new U.S. technology for geoscience and the extraction of hydrocarbon fuels also can help in closing our trade deficit to some extent, but worldwide growth for natural gas promises benefits on its own to this country.

A multinational tilt from oil toward gas would make the global energy market more stable. World reserves of natural gas are comparable to those of oil, but they are dispersed more widely. About 58 percent of all oil reserves are concentrated in the Middle East, but only 26 percent of the gas reserves lie there. Industrialized nations (the major users of gas, now and in the foreseeable future) control only 16 percent of those oil reserves but 57 percent of the gas reserves.

Nor is this a case of boosting the "haves" against the "have nots." Many populous, less-developed countries (among them Mexico, Venezuela, Argentina, Pakistan, Thailand, Nigeria, Indonesia, and China) have large natural gas resources that can be tapped more assiduously to satisfy their growing domestic needs for energy. Their broader use of low-polluting fuel is especially desirable in the face of environmental problems that can also be expected to increase as their transportation networks proliferate and industries connected to higher living standards expand.

Japan is a special case among nations. It has virtually no indigenous energy sources, and it already has contracts to bring in large amounts of liquefied natural gas from Indonesia, Alaska, Brunei, Australia, and Abu Dhabi. By the turn of the century it might add the Soviet Union and Nigeria to this list and Japan could also negotiate

with China for natural gas supplies at some future date. (The U.S.S.R., which itself consumes about one-third of all the natural gas produced in the world each year, contains approximately 40 percent of the earth's reserves.) Japan is concerned about air pollution and might determine to put great stress on gas as a transportation fuel, as well as a heat source in generating electricity.

Western Europe is scheduled to become a closer economic unit in the early 1990s; and, considered as such, it has 220 quads of natural gas reserves—with considerable potential from the Norwegian fields in the North Sea. At present, Western Europe imports gas from the U.S.S.R. and (via a pipeline under the Mediterranean) from Algeria. LNG imports from Nigeria may also begin to serve some parts of Europe within a decade or so, but its own gas production could be encouraged further. We believe that gas use there could grow safely by about the same rate as the one we projected in this report's "accelerated" case.

The "new environment" for natural gas is upon us—here and throughout the world. In this country, producers, transporters, distributors, and consumers have finally begun to look for mutual interests rather than to focus on what divides them. A new President-elect and a Congress controlled by the opposing party at least seem to have common goals. In mid-1989, a ministerial meeting of the International Energy Agency (IEA) could well begin to explore cooperative efforts to grasp the environmental, security, and economic advantages natural gas offers. The time is ripe to put priorities and policies in order.

**U.S. Leadership Can Help
Develop Wholesome Role
For Natural Gas Worldwide**

How This Study Was Conducted

When policy goals are separated from real-world *possibilities*, the results may be frustration and disappointment. Industry and government filing cabinets are replete with "wish lists" that never become more than that.

The principals of Washington Policy and Analysis sensed a formidable and rapidly growing national consensus on the multi-faceted promise of natural gas for the rest of this century and into the next. But they recognized the disturbing reality that the fuel's supply and demand in this country were both still being projected at a level that meant major potential benefits in environmental protection and greater energy security might not be realized.

A country this size does not usually change energy trends quickly except in response to a trauma, so we knew it made sense analytically to try to push our vision as far ahead as we could with rigor. The WEFA Group (newly formed in a merger of Wharton Economic Forecasting Associates and Chase Econometrics) had excellent tools to do the job and the ability to focus them simultaneously on a single task: a) its World Forecasting Service (which would be essential because of interrelationships between the United States and world markets; b) its Long-Term U.S. Macroeconomic Model; c) its gas and oil supply model; and d) its model to coordinate supply and demand for all U.S. energy sources.

We formulated conceptually the questions that had to be answered by integrated computer simulations for the years between now and 2010, then authorized WEFA to begin. Our baseline followed the reference case published by that group in July 1988. To evaluate the practical possibilities of

putting greater emphasis on gas, we injected and tested a series of assumptions in components of the model that were controllable variables. We were open to change, but also kept our eyes open to federal budgetary caution as well as to real political limitations and to the recent history of tensions among various segments of the natural gas industry itself. We tried to postulate an alternative situation that would be at least a framework for future discussion and eventual consensus. For instance:

On the supply side, we

- incorporated assumptions about a broader gas reserve base that grew out of a Department of Energy study published in the spring of 1988 (which was reinforced independently by the latest industry estimates);
- weighed the possible effects of federal R & D support that targeted, for example, the geosciences relevant to hydrocarbon deposits (a slight shift in policy emphasis that would probably be reflected in changes to the R/P ratio for natural gas—total reserves divided by annual production);
- gauged the results of tax incentives for exploration and production rather directly—because these modify returns on investment all along the line;
- considered the great progress made over the past eight years to free up energy trade on both sides of the border between the United States and Canada—even apart from the U.S.-Canadian Free Trade Agreement (whose aim in this instance was mainly to consolidate formally an already healthy set of working arrangements);

- incorporated production of "unconventional" supplies of gas from coal seams, co-production, and Devonian shale that would be available as a result of technological improvements based on research efforts; and
- added the potential for more development of gas on the North Slope of Alaska.

These assumptions, coupled with our price assumptions, provided us with an upper ceiling for available gas supply. Professor Robert Finley, of the University of Texas at Austin, reviewed the initial gas supply profiles that were produced to ensure consistency between the econometric results and geologic reality.

On the demand side, we

- adopted the basic WEFA projections for GNP and oil price;
- adjusted exploration and production levels for both gas and oil to reflect increased drilling, allowing the WEFA model to calculate the full effects on U.S. economic activity;
- developed assumptions about the industrial penetration of advances in end-use technol-

ogy, in consultation with Professor Robert Williams, of Princeton; and

- incorporated assumptions regarding "least-cost" strategies for reducing emissions to meet air quality standards (with the assistance of Professors James Fay and Dan Golomb of MIT, and David Bardin).

We compared baseline outputs with runs on the "accelerated-gas-use" scenario and noted the resulting differences in fuel-mix and trade balance over the projected time span. Then we examined the variations in order to estimate the environmental implications.

Finally, the WEFA Long-Term U.S. Macroeconomic Model incorporated all the changes in the energy sectors and the trade sectors of the economy, as well as the fiscal policy aspects of the "new gas environment," to generate the impacts that might be anticipated on the economy as a whole (GNP, employment, deficits, and so on). The results were compared with the baseline to measure the effects of the changes.

Natural Gas: Resources and Producibility. William L. Fisher, Bureau of Economic Geology, University of Texas at Austin.

Natural Gas and the Environment: Benefits for Air Quality. James A. Fay and Dan S. Golomb, Massachusetts Institute of Technology.

Advanced Gas Turbines for Power Generation. Robert H. Williams, Center for Energy and Environmental Studies, Princeton University.

The Role of Natural Gas in Energy and Environmental Policy. David J. Bardin, Arent, Fox, Kintner, Plotkin & Kahn, Washington, D.C.

Natural Gas: A Strategic Resource for the Future. A Tabular Comparison of the Baseline and "Accelerated-Gas-Use" Cases Modeled by the WEFA Group.

**Technical Papers Associated
With This Study**

Two Possible Futures for U.S. Gas Supply

Baseline Case—The Present Course (tcf)

	1990	1995	2000	2005	2010
Lower-48 conventional gas	15.8	15.8	15.1	14.9	15.5
Associated	3.3	3.1	2.8	2.6	2.5
Nonassociated	12.5	12.7	12.3	12.3	13.0
Imports	1.4	2.1	3.2	3.4	3.3
Canada	1.3	1.6	2.3	2.5	2.4
Mexico	0	0	0.1	0.1	0.1
LNG	0.1	0.5	0.8	0.8	0.8
Unconventional	0	0	0	0	0
Alaska	0	0	0	0	0
Total tcf	17.2	17.9	18.3	18.3	18.8
Total quads	17.7	18.5	18.9	18.9	19.4

Alternative Case—Recognizing a "New Gas Environment" (tcf)

	1990	1995	2000	2005	2010
Lower-48 conventional gas	16.1	16.7	17.7	18.5	18.1
Associated	3.3	3.1	2.8	2.8	2.9
Nonassociated	12.8	13.6	14.9	15.7	15.2
Imports (total)	1.5	2.5	3.7	3.8	3.8
Canada	1.4	1.5	2.4	2.5	2.5
Mexico	0.0	0.3	1.5	0.5	0.5
LNG	0.1	0.7	0.8	0.8	0.8
Unconventional	0.1	0.2	0.3	0.8	1.0
Alaska	0	0	0	0	1.2
Total tcf	17.7	19.4	21.7	23.1	24.1
Total quads	18.2	20.0	22.4	23.8	24.8

**A Research Report
of WASHINGTON POLICY AND ANALYSIS
A MILLER & CHEVALIER CONSULTING GROUP**

If the United States is to take full advantage of natural gas as a strategic resource for the future, here is a sample of what might be done in 1989:

1. Expand federal funding for research and development on the geoscience that underlies natural gas production, especially in regard to enhanced gas and oil recovery. To limit federal outlays (and to make sure that the results are put to use broadly and promptly), this could be done with industrywide support through the Gas Research Institute or through cooperative ventures linking government, industry, and universities.
2. Expand federal funding and other incentives for R & D linked to gas-use technologies—including programs designed specifically to promote the commercialization and economical penetration of the market by new combustion turbines for the generation of electricity, cooling by gas, natural-gas vehicles, and the selective use of "co-firing" with gas and other fuels.
3. Identify the onshore and offshore federal lands that are attractive targets for environmentally sensitive exploration and production, and make them more accessible to the private sector.
4. Enact a program of limited tax incentives to encourage domestic exploration for gas and oil and redevelopment drilling in older fields.

5. To take full advantage of new promise from geoscientific knowledge about hydrocarbon deposits that have been bypassed or untapped, institute a 10-percent tax credit for redevelopment drilling.

6. To clarify the ground rules for most future investment, enact complete decontrol of wellhead prices for all gas.

7. Promote a "least-cost" strategy for reducing the emissions of pollutants from energy's production and use, by implementing environmental regulations that are based on performance (for example, by favoring such low-cost options as trading emission "credits," burning gas in conjunction with other fuels, and having compliance monitored in terms of areawide "bubbles" rather than individual facilities).

8. In areas where environmental standards are not being attained, make sure that federal funds provided to local government for vehicles are used exclusively for low-polluting equipment.

9. Use all environmentally responsible procedures at the federal government's command to expedite the licensing of new capacity for pipeline delivery of gas to the Northeast.

This is no "magic formula"; but it is at least a framework for executive and legislative discussion, in that it addresses both supply and demand. Concentrating on one without the other simply does not promise to change the outlook. A new attitude toward natural gas is emerging—in the U.S. and worldwide. But it will be thwarted by either a "business-as-usual" or a piecemeal approach.

Energy Analysis

1515 Wilson Boulevard
Arlington, Virginia 22209

A.G.A. Planning & Analysis Group
January 23, 1989

TRENDS IN ELECTRIC GENERATION CAPACITY AND THE IMPACTS ON NATURAL GAS DEMAND

Digest

Growth in electricity demand, coupled with reduced plans for new facilities, has brought into question the adequacy of electric generation capacity in the mid-1990s. Recent North American Electric Reliability Council (NERC) studies show that electric utilities have continually reduced the number of planned capacity additions over the past decade. In 1988, total planned additions were 73,400 megawatts (MW) or 71 percent less than the 250,000 MW planned for the 10-year period beginning in 1979. This is reflected in an 86 percent reduction in planned coal capacity and an 85 percent reduction in planned nuclear capacity additions.

The natural gas share of planned capacity additions is expected to grow. Today, planned natural gas-based generation additions comprise the largest share, almost 40 percent, of planned utility-owned capacity additions of 100 MW and larger. A relatively new source of generation capacity is non-utility generators (NUGs), that sell power to utilities. Current projections of NUG additions exceed the level of coal and nuclear additions. Projected NUG capacity has tripled from 6,600 MW in 1985 to 19,000 MW in 1988. More than half of all new NUG additions are expected to be gas-fueled.

If peak electricity demand grows at the comparatively low rate of 1.9 percent annually between 1989 and 1997, as projected by NERC, then an additional 50,000 MW of generation capacity will be required in addition to the 32,500 MW of capacity currently under construction. However, a more rapid demand growth rate of 2.9 percent annually for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW beyond plants currently under construction, according to A.G.A. calculations.

Exhibit B

TRENDS IN ELECTRIC GENERATION CAPACITY AND THE IMPACTS ON NATURAL GAS DEMAND

Introduction

Currently, excess electric generation capacity exists in many parts of the United States. However, the recent growth in electricity demand, coupled with reduced plans for new facilities, has brought into question the adequacy of this capacity in the mid-1990s. In addition, it is important to consider what effect the increasing age of existing generation units will have on the future mix of generation equipment by fuel type. With no new nuclear units planned (beyond what is under construction) and about 14 percent of all coal-fired units expected to be 40-years old by 1997, the need for new capacity, particularly NUGs, has become likely.

The purpose of this analysis is to identify gas demand opportunities in electric generation. More specifically, trends in electricity demand growth and generation capacity additions are evaluated to determine the amount of new generation capacity needed to begin construction within the next decade and what share of this new capacity will be fueled by natural gas.

Executive Summary

- Recent NERC studies show that electric utilities have continually reduced the number of planned capacity additions over the past decade (see Figure 1).
 - In 1988, total planned additions were 73,400 MW or 71 percent less than the 250,000 MW planned for the 10-year period beginning in 1979. This is reflected in an 86 percent reduction in planned coal capacity additions and an 85 percent reduction in planned nuclear capacity additions.
 - Today, planned natural gas-based generation additions comprise the largest share, almost 40 percent, of planned utility-owned capacity additions of 100 MW and larger.
- A relatively new source of generation capacity is NUGs, that sell power to utilities. Current projections of NUG additions exceed the level of coal and nuclear additions. Figure 1 shows that projected NUG capacity has tripled from 6,600 MW in 1985 to 19,800 MW in 1988.
 - More than half of all new NUG additions are expected to be gas-fueled.
- As shown in Table 1, the most recent (October 1988)

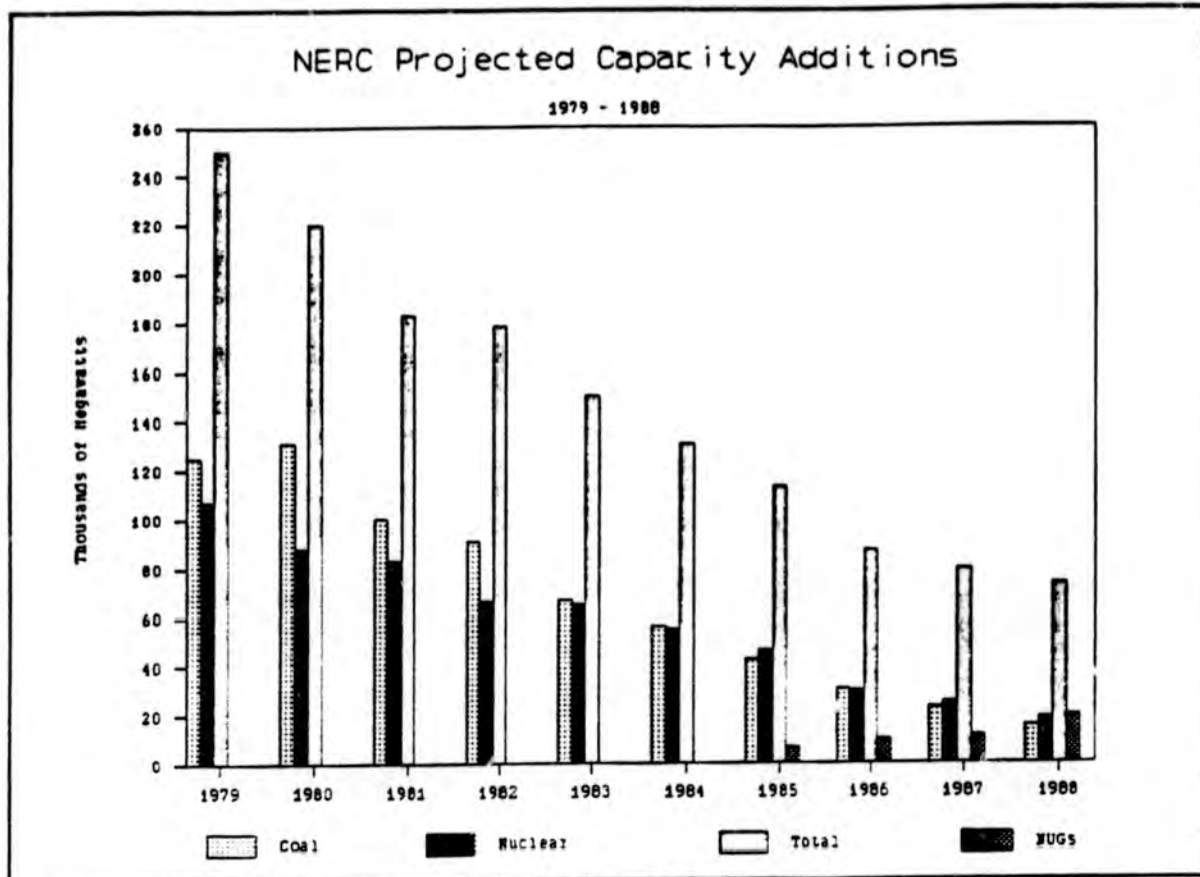


Figure 1

Table 1

**A.G.A. Estimated Capacity Shortages in 1997
Beyond Current Construction
(Megawatts)**

REGION ¹	A.G.A. Base Demand Growth Case (1.9%/year)	A.G.A. Rapid Demand Growth Case (2.9%/year)
ECAR	0	4,991
ERCOT	14,276	21,339
MAAC	3,528	6,785
MAIN	2,955	5,971
MAPP	430	2,533
NPCC	5,637	10,711
SERC	11,904	27,052
SPP	2,941	9,406
WSCC	8,080	16,038
TOTAL	49,751	104,826

¹See Appendix A for regional descriptions.

electricity supply and demand outlook published by NERC suggests that most regions could be experiencing electric generation shortages by 1997. This is based on the assumption that only those projects that are currently under construction, 32,500 MW, will reach completion.

- According to A.G.A., even if peak electricity demand grows at the comparatively low rate of 1.9 percent annually between 1989 and 1997, as projected by NERC, then an additional 50,000 MW of generation capacity will be required in addition to plants currently under construction. NERC states that some 41,000 MW is planned, but not yet under construction.
- However, a more rapid demand growth rate of 2.9 percent annually for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW beyond plants currently under construction, according to A.G.A. calculations. Even taking into account the 41,000 MW that is planned, there would still be a shortfall of 64,000 MW in 1997.
- The Energy Information Administration's (EIA) annual review of the electric utility industry also indicates that capacity requirements in the next decade far exceed current construction levels. The Annual Outlook for U.S. Electric Power 1988 projects that 126,400 MW of new generation capacity additions will be required by the year 2000.
 - Almost 60,000 MW of EIA's total projected additions are expected to consist of natural gas combined-cycle and combustion turbine generators (3,160 Bcf of gas demand). Of this 60,000 MW, NUGs are expected to contribute 17,600 MW of new gas-fueled systems.
- A recent Electric Power Research Institute (EPRI) analysis, titled "Utility Turbopower for the 1990s," predicts as much as 75,000 MW of the next 100,000 MW put in place could potentially be gas turbine-based. The analysis indicates gas-fueled capacity's low capital cost (\$300/kW for simple cycle and \$600/kW for combined cycle) and competitive gas rates makes these units the most economical choice when compared with any other alternative.

Background

From 1965 to 1974, summer peak demand for electricity grew at a 7.2 percent annual rate. To meet this high level of demand, utilities planned and constructed new baseload generation capacity 8 to 10 years before its initial operation date. However, after the oil embargo electricity demand growth

slowed. This resulted from rising electricity rates and a nationwide movement toward conservation. From 1974 to 1981, peak demand growth fell to 3.0 percent a year. This growth continued to slow in the early 1980s, which were characterized by high rates of inflation and interest along with almost stagnant economic growth. In 1982 electricity sales to end-users declined 2.8 percent, the first absolute decline since 1945. More recently, peak demand growth has started to accelerate, increasing to 3.6 and 4.0 percent in 1986 and 1987, respectively. Continued growth of this magnitude will require the construction of new plants to augment current capacity.

Figure 2 shows how generation capacity grew at a faster rate than peak demand from 1973 through 1982. This trend of rapid supply growth and declining demand growth led to an over supply or excess capacity of generation facilities and to a significant reduction in the amount of planned new additions. During the past five years, however, this trend has been reversed. From 1983 to 1987, peak demand increases have overtaken generator unit additions. The impact of this reversal has been a reduction in excess capacity as demand growth continued to outpace new supply additions.

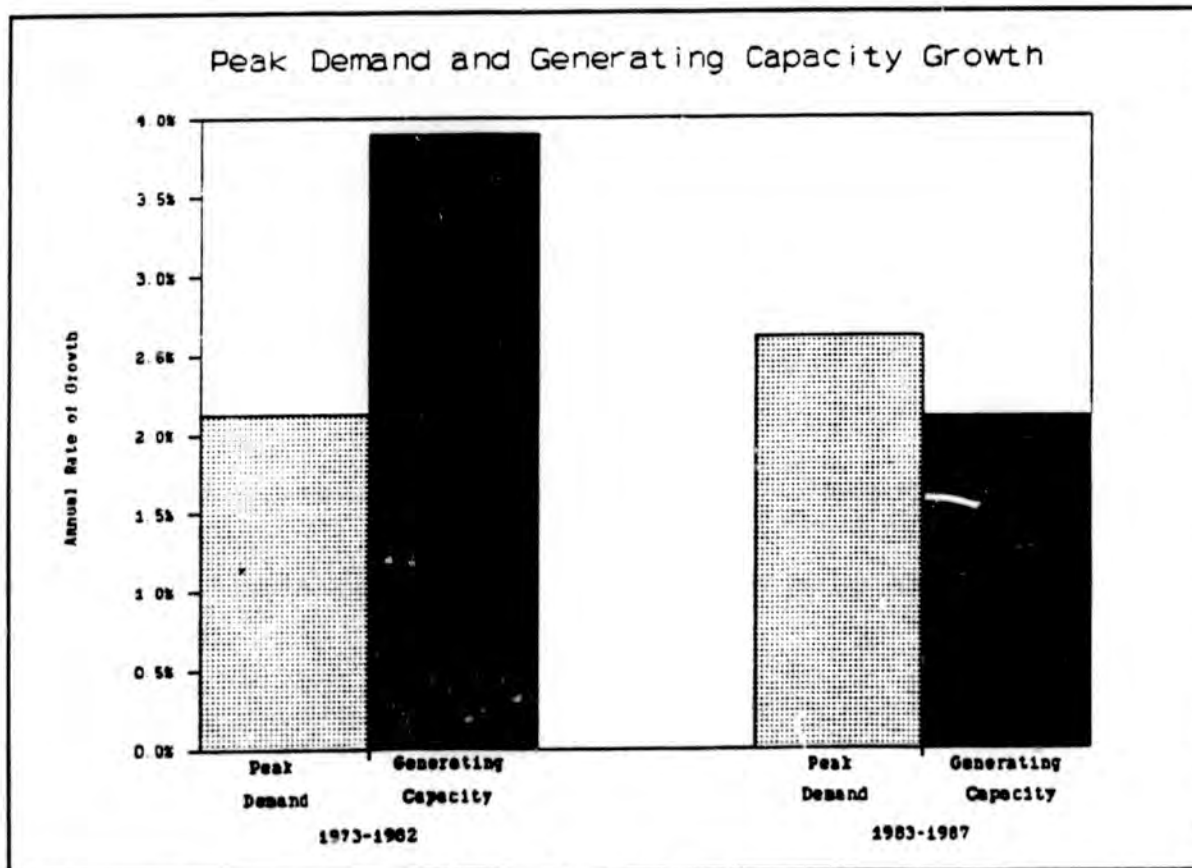


Figure 2

As excess capacity developed, relatively high interest rates further increased the cost of carrying these new additions. State commissions began to conduct prudence investigations as to whether the cost of these surplus plants should be allowed into the utilities' rate base. Plant cost disallowances were estimated to be \$12.7 billion in 1987 alone.¹ The prospect of future disallowances has made utility investment in new, capital intensive generation plants relatively more risky.

In 1984 A.G.A. analyzed nuclear plant construction trends to determine how natural gas demand may be affected.² The study determined that longer than expected lead-times for construction, changes in regulatory licensing, and less than favorable generation economics led to a number of nuclear plant cancellations. It was clear that after the current class of nuclear plants were completed, future nuclear additions were unlikely. Currently, there are 16 nuclear plants under construction and projected to become operational in less than 10 years. Two other units, Seabrook and Shoreham are completed, but not operating due to regulatory and financial problems.

Coal-fired plants were analyzed in a 1985 A.G.A. analysis.³ This study noted that the escalating capital costs required to build new coal capacity that met applicable environmental standards was higher than a number of gas-based alternatives. It also pointed out that the number of new planned coal-fired plants was decreasing, from 100,000 MW of planned capacity in 1980 down to 42,000 MW in 1985 (contrasted with 15,400 MW in 1988).

Most recently, a 1987 A.G.A. analysis determined that an additional 44,300 MW of new generation capacity over current construction levels would be needed by 1995 if peak demand grew 2.2 percent annually.⁴ It was recognized that if demand grew at a rapid 3.3 percent annually, then 98,500 MW would be required. The analysis discussed a number of natural gas-powered generation options that can play a significant role in satisfying these capacity requirements. In particular, 1988 data indicate that gas combined-cycle and combustion turbine systems are expected to make up the largest share of unplanned future additions.

Methodology

A number of industry-wide analyses were considered in evaluating electric generation capacity and electricity demand trends in an effort to determine the extent to which gas-based systems will be needed to satisfy future generation requirements. The two principal studies evaluated in the area of future capacity needs based on utility power pool data were: NERC's 1988 Reliability Assessment; and the Department of Energy's (DOE) Staff Report Electric Power Supply and Demand for the Contiguous United States 1987-1996.^{5,6}

The NERC study questioned the adequacy of future electric generation capacity, especially during the mid-1990s, while the DOE report concluded that several regional power pools, primarily ranging from New England to the Southeast, would develop generation shortages. Both of these studies assume that some 73,400 MW of additional new capacity will become available between now and 1997 even though 40,900 MW of this capacity is not yet under construction. Furthermore, the DOE report indicates that reliability can be maintained only if all of the projected capacity is completed as currently scheduled, and that new construction of additional capacity be available for commercial operation by 1992.

In order to evaluate utilities' installed generation capacity, peak demand loads and future capacity additions, NERC's 1988 Electricity Supply and Demand study was used.⁷ This study defined planned capacity additions as those plants that are planned for construction. However, in most cases these additions are not actually utility authorized for construction. Therefore, in order to more realistically determine the degree to which future electricity demand will be met by additions to the current generation stock, only those capacity additions currently under construction were used.

Given NERC projections of installed generation capacity, each annual figure was adjusted downward to reflect the additional on-line capacity of only those plants currently under construction and scheduled to become operative during the year in question. This procedure was performed for each year, 1989-1997. Given adjusted installed capacity and peak demand (either Base Demand Growth Case or Rapid Demand Growth Case figures), capacity margins were calculated using the following formula:

$$\frac{\text{Adjusted Installed Capacity} - \text{Peak Demand}}{\text{Peak Demand}} \times 100\%$$

All areas with calculated capacity margins 20 percent and larger were deemed to have sufficient capacity. In other words, available capacity exceeds peak demand by 20 percent. However, regions that fall below 20 percent are projected to have capacity shortages. Table 1 shows the results of this analysis by describing the potential shortfall (i.e. the volume of capacity that falls short of the 20 percent capacity margin test) for each electricity sub-region. As a means of assessing the availability of capacity in the face of forced outages, scheduled maintenance or capacity reductions due to emission restrictions, the 20 percent capacity margin approach is generally accepted.

The results of this capacity margin analysis were then compared with the recent EIA study, Annual Outlook for U.S. Electric Power 1988.⁸ This study projects generation requirements given a number of assumptions concerning

retirements, plant efficiencies, capacity factors, etc.

Results

● Historical Perspective

Slowing demand growth was one factor leading to a reduced rate of capacity additions in the 1980s. Large cost overruns associated with ambitious attempts to build power plants that were much larger than previous units, coupled with the financial impact of high interest rates on these large investments, also had a definite dampening effect on utility planners. In response to these developments, utilities continually reduced the number of future planned additions over the past 10 years. In 1988, planned additions were 73,400 MW or 71 percent less than the 250,000 MW planned 10 years earlier in 1979. Similarly, the number of planned coal and nuclear plants has fallen from 125,000 MW and 107,000 MW in 1979 to 15,400 MW and 18,200 MW in 1988, respectively. On the other hand, since NERC began projecting NUG additions, this capacity has tripled from 6,600 MW in 1985 to 19,800 MW in 1988. These additions exceed the projections of new coal and nuclear capacity.

NERC, a federation of nine regional power pools representing investor-owned, federal, rural, cooperative, state, and municipal electric utilities, currently forecasts additions of 73,400 MW of generation capacity by 1997. Of this, only 32,500 MW is actually under construction. The remaining 40,900 MW of capacity is in the planning stage. Table 1 shows that if peak demand grows at the rate of 1.9 percent annually as NERC projects, then an additional 49,751 MW (versus the 40,900 MW) will need to be built beyond the 32,500 MW under construction. In a more rapid growth case where peak demand is assumed to grow at 2.9 percent annually through 1997, 104,826 MW of additional capability would be required. These additions supplement the 32,500 MW currently under construction. Appendix B lists these calculated shortfalls by NERC region and sub-region by year through 1997.

These results are similar to A.G.A.'s findings nearly two years ago, suggesting no recent improvement in future capacity availability. Using data from the NERC report, 1986 Supply and Demand, that study found that a base peak demand growth of 2.2 percent a year from 1986 to 1995 would result in shortages of 43,500 MW. The rapid case scenario of 3.3 percent demand growth showed that an additional 98,500 MW would be needed. This year's report, however, assumed smaller demand increases compared with earlier years, based on NERC's projection of demand growth. This year's report, therefore, suggests that even at slower rates of growth of peak electricity demand, future generation capacity will be inadequate by the mid-1990s. In addition, NERC's 1.9 percent peak demand growth rate can be characterized as overly conservative since the last two years peak demand has grown 3.6 and 4.0 percent, respectively.

**NERC Planned Utility-Owned Generator Unit Additions
100 MW or More - Not Under Construction**

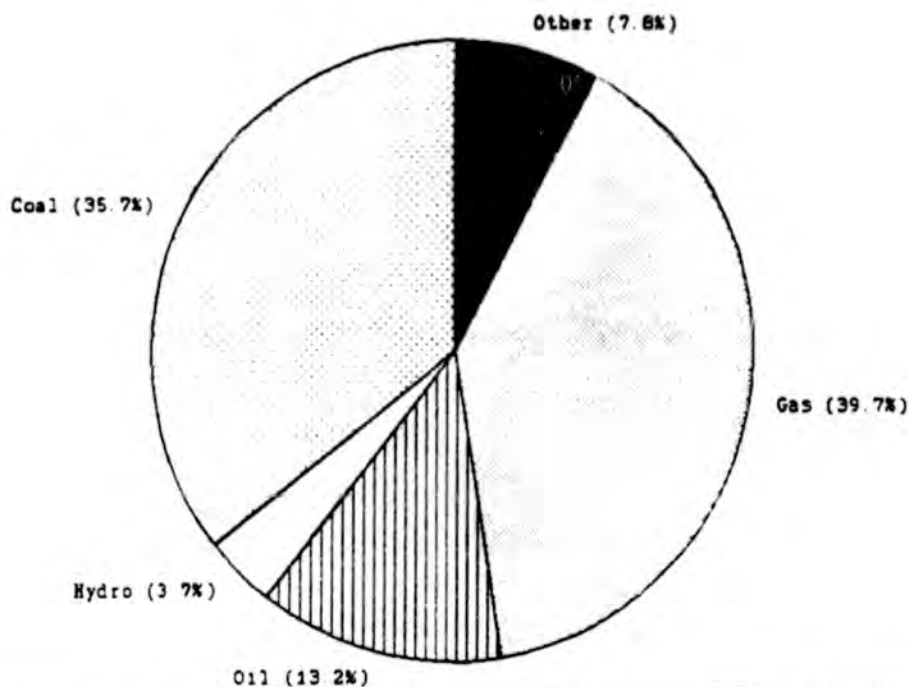


Figure 3

● Future Outlook

As electricity consumption growth outstrips the rate of new capacity additions, excess capacity diminishes and a significant amount of new capacity additions will be required to ensure system reliability by the mid-1990s. If peak electricity demand grows 1.9 percent annually between 1989 and 1997, then an additional 49,751 MW of generation capacity will be required in addition to plants currently under construction. However, a more rapid demand growth rate of 2.9 percent for this period, conservative by recent standards, necessitates the additional construction of almost 105,000 MW. In contrast, 40,900 MW are planned beyond current construction levels, according to NERC.

Natural gas-fueled combined-cycle, ISTIG (inter-cooled steam-injected gas turbines), and combustion turbines are expected to make up a major share of this new capability. Given the uncertainty, public resistance and high costs associated with building nuclear power plants, future baseload additions will most likely consist of coal-steam and gas combined-cycle units. Coal-steam plants have generally been the conventional choice for baseload systems. But today, gas-based systems on the average enjoy lower life-cycle costs than coal-steam plants.

In fact, recent advances in combustion turbine technology

Given these probable shortfalls in generation capacity, what measures can be taken to remedy this potential problem? Increased bulk power transfers are often cited as remedies in regions where power is short. However, as Table 1 shows, all areas in the rapid case experience shortages in generation capacity in 1997. Therefore, it is questionable where surplus capacity will originate that will permit power transfers. Another possible solution is for utilities to reduce their capacity margins from 20 percent to 15 percent. Indeed, some utilities have been able to operate reliably in this fashion. But for the nation's combined generation system, this is not practical. Over the past four summer peak demand periods, an average of 15.5 percent of the nation's generation stock has been unavailable because of forced outages, scheduled maintenance, and "other" outages. It is apparent that increased bulk power transfers and reducing capacity margins cannot be substituted for new capacity additions.

Exacerbating the problem of tight generation supplies is the status of nuclear power. Once regarded as cost efficient and pollution free, projected nuclear additions are declining. Not one nuclear plant has been ordered since 1978. There are currently 16 nuclear plants more than 50 percent complete rated at 18,200 MW of capacity. However, it is questionable whether all of these plants will become operable over the next 10 years. Seven of these plants do not have reliable start-up dates. Also there are four Tennessee Valley Authority (TVA) plants under construction whose completion dates are unknown. Construction of these units has been slowed to allow safety investigations at TVA's five completed plants. If these plants are not operating by the mid-1990s, then an even larger amount of new capacity will be required.

Another possible solution would be to build new coal-steam generation plants. NERC projects an additional 15,400 MW of coal capacity will also be available by 1997. But given the 10- to 12-year lead times required for regulatory approval and construction, it is doubtful whether all of this new capacity will become available. Fourteen plants rated at 9,500 MW are currently under construction. The remaining 5,900 MW of coal capacity include utility planned but unauthorized plants, plants waiting to receive regulatory approval and units with regulatory approval, but not yet under construction. It is questionable whether these plants will be available for operation before 1997. However, NERC expects gas-based systems to comprise a major share of future additions. Figure 3 shows these systems are gaining favor with electric utilities. Of the total amount of planned capacity additions 100 MW or larger not currently under construction, natural gas capacity leads all other categories, including coal systems, with almost a 40 percent share.

have resulted in relatively more efficient and reliable gas combustion turbines rated between 135 and 150 MW. These systems are far cleaner burning than coal systems equipped with state-of-the-art pollution control equipment. When these new turbines are combined with a heat-recovery system, efficiencies rise to 45-47 percent. A recent analysis by the EPRI indicated that as long as natural gas costs less than \$6 per million Btu, gas-fueled capacity's low capital cost (\$300/kW for simple cycle, \$600/kW for combined cycle) gives it the lowest projected cost of electricity compared with any alternative now available or expected in the next several years. The analysis also indicated that as much as 75,000 MW of the next 100,000 MW of new capacity put in place could potentially be gas turbine based.¹⁰

The competitive advantages of these gas-based systems has led to a significant amount of this capacity being built by non-utility generators or NUGs. These additions have been induced by implementation of the Public Utility Regulatory Policies Act (PURPA) of 1978. A section of this act provides for cogenerators that meet PURPA's operating standards to sell self-generated electricity to electric utilities. The electricity these industrial producers generate reduce the need for additional utility generation by reducing its demand upon the electric utility and by selling its additional supplies of electricity at the utility's designated avoided cost. A.G.A. estimates that 45 percent of total existing cogeneration capacity, some 17,300 MW, is gas-fueled.¹¹

NERC states that projected NUG generation capacity has grown more than 300 percent since 1985. NUGs are expected to provide almost 27 percent or 20,128 MW of generation capacity to the industry by 1997. A complete break-out of NUG capacity by fuel type is not available. This is because many utilities are not reporting fuel requirements for their cogenerators. Table 2 breaks down projected NUG additions by fuel type. Gas is clearly the dominant generation fuel. More than 47 percent of all fuel-designated capacity is gas driven. It is estimated that more than half of the capacity labeled "other or unknown" will also be gas driven. This estimate is corroborated by EIA, which projects that 60 percent of future NUG additions will be gas-fueled.¹²

How long utilities can refrain from constructing large amounts of new capacity additions will depend on the rate of future demand growth. In 1986 and 1987, peak demand increases were 3.6 and 4.0 percent, respectively. Growth in 1987 was twice the rate projected by NERC's 1987-1996 forecast. The summer heat wave in 1988 pushed demand to record levels for a number of utilities. Another explanation for this accelerated growth in demand is that real electricity prices are falling. Least-cost planning, relatively low capital expenditures, and relatively lower fuel input prices have resulted in lower rates. In 1987, average real electric rates dropped 5.7 percent. It should be noted that average real gas prices for electric generation dropped 10.5 percent.

Table 2

NERC Projected Non-Utility Generator Additions
by Fuel Type 1988-1997

<u>Fuel Type</u>	<u>MW</u>	<u>% of Total</u>
Natural Gas	3,029	15.0
Hydro	500	2.5
Coal	1,315	6.5
Geothermal	594	3.0
Wind	84	0.4
Solar	100	0.5
Refuse (Solid Waste)	458	2.3
Wood/Wood Wastes ¹	346	1.7
Other or Unknown	13,702	68.1

¹Believed to be mostly gas-based capacity.

The belief that large amounts of new generation capacity are needed is also embodied in the Energy Information Administration's (EIA) Annual Outlook for U.S. Electric Power 1988. Given assumptions concerning capacity factors, plant efficiencies, retirements, refurbishment, capital costs, and fuel costs, the study projects that 126,400 MW of new capacity, will be required by the year 2000. Almost 60,000 MW of this capacity would be fueled by natural gas.

The analysis classifies new additions into planned, unplanned, and non-utility categories. Planned additions are generally analogous to NERC's "additions under construction" classification. All of this capacity, some 44,200 MW, is projected to become operable. Only 3,500 MW is gas-driven. In contrast, the study sees an additional 52,800 MW of unplanned utility additions becoming available by 2000. About 72 percent of these additions or 38,400 MW is expected to be either gas combined-cycle or combustion turbines. Additions by NUGs are projected to add another 29,400 MW to the system. About 60 percent of all NUG additions are expected to be fueled with natural gas.

Conclusion

Over the past decade the electric utility industry has continually reduced its plans to build new generation capacity. The two major types of generation supply--nuclear and coal systems--have followed this trend. In fact, natural gas holds the largest share of planned additions 100 MW or larger, but not yet under construction. On the other hand, non-utility generation sources are expected to increase significantly. Both NERC and EIA data suggest that natural gas will account for a

majority of new NUG additions. Because of the competitiveness of natural gas systems, combustion turbine, ISTIG, and combined-cycle units are expected to account for 60 percent of future NUG additions. As generation supply continues to tighten in the mid-1990s, these gas-driven systems will provide the most cost-effective, the most fuel-efficient and the most time-effective means of meeting rising electricity demand levels.

FOOTNOTES

1. Energy Information Administration, Annual Outlook for U.S. Electric Power 1988, DOE/EIA-0474(88), (Washington, DC: G.P.O., August 24, 1988).
2. American Gas Association, "Impact of Nuclear Plants' Anticipated Costs on Future Electric Prices," Energy Analysis 1984-14, (Arlington, VA: A.G.A., November 9, 1984).
3. American Gas Association, "Analysis of New Coal-Fired Electric Generation Capacity," Energy Analysis 1985-11, (Arlington, VA: A.G.A., July 3, 1985).
4. American Gas Association, "Gas Options to Offset Anticipated Electric Generation Shortages in the mid-1990s," Energy Analysis 1987-3, (Arlington, VA: A.G.A., May 21, 1987).
5. North American Electric Reliability Council, 1988 Reliability Assessment, (Princeton, NJ: NERC, September 1988).
6. U.S. Department of Energy, Staff Report Electric Supply and Demand for the Contiguous United States 1987-1996, DOE/IE-0008, (Washington, DC: National Technical Information Service, February 1988).
7. North American Electric Reliability Council, 1988 Electricity Supply and Demand, (Princeton, NJ: NERC, October 1988).
8. Energy Information Administration, Annual Outlook for U.S. Electric Power 1988.
9. U.S. Department of Energy, Staff Report Electricity Supply and Demand for the Contiguous United States 1987-1996.
10. Electric Power Research Institute, "Utility Turbopower for the 1990s," EPRI Journal, April/May 1988.
11. American Gas Association, "Estimated Current Natural Gas Cogeneration Capacity: 1988 Update," Planning and Analysis Issues 1988-4, (Arlington, VA: A.G.A., March 18, 1988).
12. Energy Information Administration, Annual Outlook for U.S. Electric Power 1988.

Appendix A

North American Electric Reliability Council Listing of Regions and Subregions

Regions

ECAR
East Central Area Reliability
Coordination Agreement

ERCOT
Electric Reliability Council
of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-American Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating
Council

SERC
Southeastern Electric Reliability
Council

SPP
Southwest Power Pool

Subregions

None-Michigan, Indiana,
Ohio, Kentucky, West
Virginia

None-Texas

None-New Jersey,
Pennsylvania, Maryland,
Delaware

CE-CMNWLTH EDISON-
Commonwealth Edison
Company Subregion
(North Illinois)
EM-EAST MISSOURI-East
Missouri Subregion
SCI-S. CENT. ILLINOIS-
South Central Illinois
Group
WUM-WIS-UPPER MICH.-
Wisconsin-Upper
Michigan Subregion

None-N. Dakota, S. Dakota,
Nebraska, Minnesota,
Iowa

NY-New York-New York Power
Pool
NE-NEW ENGLAND-New England
Power Pool

FL-FLORIDA-Florida
Subregion
SOU-SOUTHERN-Southern
Subregion
TVA-Tennessee Valley
Authority Subregion
VAC-VACAR-Virginia
Carolinas Subregion

SE-SOUTHEAST-Western
Mississippi,

WSCC
Western System Coordinating
Council

Southeastern Texas,
Eastern Arkansas,
Southeastern Missouri
and Louisiana
WC-WEST CENTRAL-Western
Arkansas, the Texas
Panhandle, Northeast
Texas, and Oklahoma
N-NORTHERN-Western
Missouri and Kansas

NWP-NW POOL-Northwest
Power Pool Area
RMP-ROCKY MT. AREA-Rocky
Mountain Power Area
AZN-ARIZ-N.MEX.-Arizona-
New Mexico Power Area
CNV-CALIF-SO.NEV.-
California-Southern
Nevada Power Area

Appendix B

Appendix B contains two tables: one showing projected electric generation shortages by year through 1997, and the other showing the comparison of expected capacity growth rates for plants under construction only to a range of peak electricity demand growth rates. Only those areas with shortages are represented.

The table "Electric Generating Shortages" shows the megawatt additions required to satisfy a 20 percent capacity margin. Zero values indicate capacity margins about 20 percent, i.e. surplus capacity.

Note that a region's calculated Base Demand Growth Case shortage depends on its base peak demand growth rate. Similarly, the Rapid Demand Growth Case shortages are dependent on the rapid peak demand growth rate. The column labeled "86 EA Reported Numbers" refers to the rapid growth case scenario of an earlier analysis using 1986 data. These rates are shown in the adjoining table.

Note: The nine pages of backup tables are not included in this copy.