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1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010

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Foreword

This report summarizes the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand, which has been adopted as a major input to the planning cycle leading to the development of Gas Research Institute's (GRI) 1990 research and development program. The baseline projection represents the GRI planning outlook for the economic and energy supply and demand situation to the year 2010. The 1988 projection was developed independently by GRI using publicly available data and a framework of commercially available models that GRI has modified over several years. It is not derived from the views of GRI member companies.

Strategic planning of GRI's R&D program requires an appreciation of the outlook for national energy supply and demand and an estimate of the role that natural gas will play within that outlook. Another key element in GRI's R&D program planning is an assessment of the benefit that would accrue from the successful development of each individual research project being evaluated for funding. The development of a consistent framework that establishes a likely projection of future energy supply and demand is critical to this assessment process. The framework that forms the scenario and data base for these planning decisions is called the baseline projection. The baseline projection supports the strategic planning of the GRI R&D program—the selection of projects for R&D funding, the development of criteria for judging the success of R&D progress, and the evaluation of benefits from R&D.

The results of a number of special analytical studies were used to modify the methodology and to enhance the detail available from the 1988 baseline projection. This year's projection includes updated base-year data, additional updates to the data base used in the industrial sector model, modifications to the petroleum refinery methodology, the continued update of the GRI Hydrocarbon Model, and numerous other assumption revisions.

This report presents a series of summary tables, sectoral breakdowns of energy demand, and the natural gas supply and price trends. The appendices include a discussion of the methodology and assumptions used to prepare the 1988 projection, a comparison with GRI's previous baseline projection, and a discussion of additional data used in developing the projection.

A companion document to this *Insights* article on the baseline projection, "Policy Implications of the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010," is also available. The Implications paper provides a brief summary of the baseline projection and also summarizes the implications of eight alternative futures studied by GRI over the last year. The alternative futures reflect an increased environmental policy emphasis, higher levels of economic growth, lower levels of economic growth, the impact of economic cycles, an increased service sector emphasis, higher electricity prices, higher energy prices, and the impact of lower energy prices.

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Executive Summary

The production of the GRI baseline projection is an ongoing process. GRI modifies the model methodology and assumptions annually to incorporate the results of economic research, to reflect current energy market trends, and to recognize new historical data.

In summary, the 1988 projection is one of steady economic growth, although at rates less than historical norms, with energy prices increasing only gradually from today's low base levels. Continued conservation trends moderate energy demand in all end-use sectors. Much of the future conservation results from embedded changes in energy-using practices prompted by the oil price spikes of the 1970s.

Within this context, the 1988 GRI Baseline Projection continues to indicate that natural gas will play a major role in a highly competitive energy mix well into the next century. However, the projection confirms that the major opportunities to sustain or increase natural gas consumption are closely related to the successful development of new gas utilization and gas supply technologies. New gas utilization technologies for applications such as cogeneration, cooling, and electric generation will help to maintain the role of gas in serving overall U.S. energy requirements in the coming years. New supply technologies, particularly advanced techniques for production from unconventional gas resources, will enhance the competitive position of gas in interfuel competition and assure the reliability of long-term supplies. Intense interfuel competition at the burner tip will also place increasing emphasis upon technologies to improve the efficiency of gas transportation and distribution.

The summary results of the 1988 GRI Baseline Projection are shown in Tables 1 and 2.

Total primary energy consumption is expected to grow at an average annual rate of 1.0 percent, or less than half the rate of GNP growth, and increase from 1987 base-year levels of 79.3 quads to 99.8 quads by the year 2010. The energy intensity of the economy, therefore, is declining throughout the projection, reflecting continued efficiencies of energy utilization and continued economic restructuring away from energy-intensive activity.

The projected overall balance among the primary energy sources and ultimate energy services is rational and achievable based upon current policies and projected economic trends. However, given the existing

Table 1. 1988 GRI Baseline Projection of U.S. Primary Energy Consumption (Quads)

	Actual 1987[a]	1995	2000	2010
Petroleum	32.9	35.3	37.4	38.9
Gas[b,c]	17.5	18.3	18.6	19.0
(Total Gas Fuels)[d]	(17.6)	(18.6)	(18.9)	(19.4)
Coal	18.0	19.3	20.9	26.2
Nuclear	4.9	6.5	6.7	6.5
Hydro	3.0	3.5	3.5	3.6
Renewables[e]	3.0	3.6	4.3	5.6
Total	79.3	86.5	91.4	99.8

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Excludes synthetic gas from petroleum and coal.*
[c] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*
[d] *Total gas fuels includes 0.3 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in each of 1995 and 2000 and 0.4 quad in 2010.*
[e] *Includes wood, solar, direct geothermal heat, etc.*

Table 2. 1988 GRI Baseline Projection of Gas Demand by Sector (Quads)

	Actual 1987[a]	1995	2000	2010
Residential	4.5[b]	4.6	4.6	4.4
Commercial	2.4[b]	2.6	2.7	3.0
Industrial[c]	7.3	7.5	7.1	6.9
Electric Generation	2.9	3.3	3.8	4.3
Transportation[d]	0.5	0.6	0.7	0.8
Total[e]	17.6	18.6	18.9	19.4

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*

[b] *Historical Energy Information Administration (EIA) statistics for 1987 do not disaggregate data for the residential and commercial sectors. Actual data for 1987 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.*

[c] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*

[d] *Includes 0.2 quad of demand by methane vehicles in 2010. The estimate of gas consumed in methane vehicles reflects the estimate of the A.G.A. Gas Demand Committee.*

[e] *Includes 0.3 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in each of 1990 and 2000 and 0.4 quad in 2010.*

energy supply and demand infrastructure, if new major restrictions were imposed on the use or availability of the major energy sources, it would be difficult to substitute alternative energy supplies. Such a disruption could lead to energy shortages and rapidly rising energy prices.

Primary natural gas consumption is projected to grow at an average annual rate of 0.4 percent, from 17.5 quads in 1987 to 19.0 quads by 2010. While this represents a stable market outlook, it involves shifts between diminishing traditional uses in the industrial and residential sectors and increasing requirements in the electric utility and commercial sectors.

The projection anticipates the availability of a few selected new gas technologies resulting from GRI's program for which technical characteristics, economics, and market entry dates are reasonably predictable. It does not reflect the entire potential impact of gas R&D and is in that sense a baseline future for the evaluation of potential R&D strategies.

Furthermore, this projection includes no estimate of potential demand for natural gas to serve new environmental functions, such as power plant emission control, waste incineration, or large-scale transportation use.

Primary petroleum consumption grows from 32.9 quads in 1987 to 38.9 quads by 2010. The refiner acquisition cost of crude oil assumes rough stability at about the current price level until after 1990, a tightening market with real price escalation beginning in the 1990s, and increasing escalation after 2000 as Middle East sources again dominate supply. U.S. refiner acquisition costs in current dollars (1987$) reach about $27 per barrel in 2000 and $42 per barrel in 2010.

At these prices, U.S. petroleum consumption is projected to increase at a rate slightly below that of total energy demand. Although about half of the increase occurs in transportation uses, demand growth is substantial in industrial uses, particularly feedstocks. Increased use by electric utilities in existing oil-burning facilities and new peaking units is also expected.

Domestic petroleum production is projected to decline from nearly 10 million barrels per day in 1987 to 6.6 million in 2010. Oil imports, therefore, reach 12.4 million barrels per day by 2010.

Coal consumption is projected to grow at 1.7 percent annually, much more rapidly than overall energy demand. Coal consumption grows from 18.0 quads in 1987 to a projected 26.2 quads in 2010. The predominant increase in coal use, of course, is in the generation of electricity, and reflects a projected rate of growth in the requirement for centrally generated electricity of 1.6 percent per year or at 70 percent of the rate of growth in GNP. This increase in electricity demand is below that shown in many contemporary projections.

The near-term projection reflects the current public opinion of constraints on nuclear power plants and assumes only the completion of the nuclear construction program begun in the 1960s and the continued operation of those plants that have not been affected by policy restrictions. After 1990 nuclear energy remains at roughly 6.5 quads through 2010. Nuclear generating capacity is projected to peak at 102.6 gigawatts in 1994. By the end of 1987, over 93 gigawatts of nuclear generating capacity are in place and operating. By 2010, after retirement of some older nuclear facilities, the projection includes 97 gigawatts of nuclear generating capacity.

The outlook for renewable energy consumption (hydro and renewables) is impacted adversely by the softer near-term energy prices. As a result, renewable consumption remains relatively level at approximately 6.0 quads through 1990. With increasing energy prices after 1990, investment in renewable energy is projected to increase, growing to 9.2 quads by 2010.

While the baseline projection presents a balanced supply and demand situation, there is much uncertainty about the future direction of energy markets, which could result in a very different outlook. GRI from time-to-time develops alternative projections to explore some of the alternative futures that could impact the planning of GRI's R&D program. As part of producing the 1988 baseline projection, GRI analyzed the implications of eight alternative futures. The alternative futures studied reflect an increased environmental policy emphasis, higher levels of economic growth, lower levels of economic growth, the impact of economic cycles, an increased service sector emphasis, higher electricity prices, higher energy prices, and the impact of lower energy prices.

The alternative future projections and the implications arising from them are discussed in the *GRI Insights* "Alternative Futures to the 1988 GRI Baseline Projection."

I. Introduction

Gas Research Institute is an independent, not-for-profit organization that plans, manages, and develops financing for a cooperative research and development program for the mutual benefit of the natural gas industry and its customers. The research program consists of over 500 active research projects in natural gas supply and end use, and in gas industry operations, as well as related basic research.

The strategic planning and appraisal of GRI R&D programs and projects depend upon a consistent analytical framework that establishes a likely projection of future energy supply and demand and defines the probable role of the gas industry during the time frame in which the GRI R&D program is expected to have its impact. The framework that forms the scenario and data base for these planning decisions is called the baseline projection. The baseline projection supports the strategic planning of the GRI R&D program—the selection of projects for R&D funding, the development of criteria for judging the success of R&D progress, and the evaluation of benefits from R&D. GRI updates the baseline projection annually to better reflect the constantly changing energy markets and to improve the framework for planning GRI's R&D program.

The 1988 projection was developed independently by GRI using publicly available data and a framework of commercially available models that GRI has modified over several years. It is not derived from the views of GRI member companies. Specific models used included Data Resources, Inc.'s (DRI), Energy and Macroeconomic Models; the GRI Hydrocarbon Model maintained by Energy and Environmental Analysis, Inc. (EEA); the GRI Regional Sectoral Electricity Model (RSEM) maintained by DRI; the EEA Industrial Sector Technology Use Model (ISTUM) and Pipeline/Flowing Gas Model; and the Resource Data International (RDI) Coal Model.

Production of the GRI baseline projection is an ongoing process. The 1988 GRI Baseline Projection includes a number of revised assumptions resulting from changes in external circumstances affecting the U.S. energy system that have occurred since the previous projection was completed. Furthermore, comments received on the 1987 GRI Baseline Projection have also influenced the 1988 assumptions.

The results of a number of special analytical studies were also used to modify the methodology and to enhance the detail available from the 1988 baseline projection. A number of changes made in the 1988 projection are the primary cause of many of the differences between previous GRI baseline projections and the 1988 projection. A more complete discussion of the GRI baseline projection methodology and changes incorporated in the 1988 baseline projection are presented in Appendices A and C.

Some of the more important changes made in the 1988 projection include:

- The continued revision of the industrial data base based on data provided by Energy Environmental Analysis, Inc. (EEA) to reflect the changing relationship between industrial output and energy consumption in response to changes over the last few years in relative energy prices, improvements in manufacturing technology, and increased foreign competition, among other factors.

- The adoption of revisions to the refinery methodology based on work by Sobotka, Inc., which were intended to make the projection of petroleum prices more consistent with the world oil price outlook and with specific economic and technical constraints found in refineries.

- The update of the GRI Hydrocarbon Model to reflect the impact of changing gas transmission patterns and the improved recovery of gas-in-place.

The initial economic, policy, and major energy assumptions for this projection were developed in consultation with the GRI Energy Economics Project Advisor Group and the Operating Committee. The projection also was presented to GRI's Operating Committee, Board of Directors, and Advisory Council in a preliminary form. This summary and the detailed backup tables, containing internally consistent energy and economic projections, were prepared for use by GRI in strategic planning and technology assessment and for other analytical requirements. It is available to analysts in GRI's member companies, other segments of the energy industry and government, and to other interested users.

In summarizing the results of the projection, this paper:

- Presents the basic assumptions underlying the projection

- Presents a summary of the 1988 GRI Baseline Projection
- Discusses the changes in the projection relative to the previous projection
- Describes the general methodology used to develop the 1988 projection.

II. Basic Assumptions

The 1988 GRI Baseline Projection assumptions were developed to reflect GRI management's judgments concerning key variables. The major assumptions include the following:

Gross National Product

- It is not GRI's intention to develop detailed economic projections. However, in the course of producing the projection, an internally consistent set of economic parameters was developed for use in modeling the energy markets.

- The pattern of economic growth used in the baseline projection follows a smooth path, with actual output approximately paralleling the path of potential economic output. The projection does not reflect actual business cycles, but reflects the mean of business cycles that will inevitably take place in coming years.

- In developing the assumptions for the baseline projection, GRI does attempt to reflect the near-term expectations for economic growth. Economic growth in the first 2 years of the projection is set equal to the consensus forecast of the large economic services.

- The average real GNP growth in the 1988 baseline projection is projected to be a relatively steady 2.3 percent per year between 1987 and 2010. The projection includes some fluctuations in the rate of economic growth, but it generally remains close to the average rate over the entire projection time period.

- The rate of economic growth in the projection appears to be somewhat slower than recent history. However, since WWII the average real rate of growth in GNP in each decade has steadily declined from 4 percent in the late-1940s to about 2.5 percent in the 1980s. Much of this progressive decline in the percentage rate of economic growth is a statistical anomaly created by the growing dollar denominated base-year level of GNP. This is highlighted by the fact that despite the decline in the percentage rate of growth, average real (1982$) GNP growth measured in dollars has progressively grown in each decade. In the late 1940s, average GNP growth per year was about $46 billion; by the 1980s, it averaged over $88 billion per year.

- To reach a real rate of growth of even 2.3 percent per year in the 1990s will require real GNP growth, measured in 1982 dollars, of over $106 billion per year. To maintain the 2.3 percent rate of growth after the year 2000 will require growth in the dollar denominated GNP of almost $127 billion per year, almost 50 percent greater than the growth rate achieved in the 1980s. The achievement of even this level of growth in real GNP under conditions of flat population growth (relatively rapid population growth was a prime contributor to the earlier historical growth in GNP) will require a rapid growth in capital investment in the U.S. economy to improve productivity and the establishment of new markets for the goods produced.

- The 1988 baseline projection does not reflect an inordinate growth in the level of U.S. capital investment or in population growth. As a result, the percentage level of GNP growth declines over the projection relative to earlier time periods. However, if immigration laws are revised to allow substantially higher levels of immigration or if tax incentives encourage higher levels of investment, the rate of economic growth could be higher than that included in the baseline projection.

- Some of the key economic and demographic variables are presented in Appendix D.

Inflation

- The inflation rate used in the projection (GNP Implicit Price Deflator) is consistent with the projected economic growth path. As was the case with GNP growth, GRI attempts to reflect the near-term expectations for inflation by setting the inflation rate in the first 2 years of the projection equal to the consensus forecast of the large economic services.

- The average inflation rate is projected to be 4.4 percent per year between 1987 and 1995 and 5.3 percent per year between 1995 and 2010. Overall, between 1987 and 2010, inflation is projected to increase at 5.0 percent per year.

Regulations

- The regulatory environment in which the gas industry operates today is changing very rapidly. Less than two decades ago, gas prices were generally set under long-term contracts, a moratoria existed on new gas hookups, and little gas-to-gas competition occurred. Since the early-1980s, the regulatory environment in the gas industry has become much more pro-competitive.

- The baseline projection and, in fact, most models assume a "workably" competitive market that does not reflect or predict regulatory behavior changes. The baseline projection incorporates the impacts of regulation where they are visible and historical experience exists. In cases where regulation is very explicit—for example, the Fuel Use Act—the baseline projection will include the obvious impacts. However, as a general rule, GRI has not tried to anticipate regulatory changes in the projection.

- The environmental assumptions used in the projection are consistent with existing environmental laws and standards. No attempt has been made to impose the impact of pending acid rain legislation or other potential policy initiatives on the projection.

- The Natural Gas Policy Act (NGPA) is assumed to operate as currently enacted over the projection time frame; however, the incremental pricing provisions of the NGPA are assumed to be inoperative in the projection.

- The 1988 GRI Baseline Projection reflects the repeal of the gas-use prohibitions of the Fuel Use Act.

Crude Oil Prices

- The oil price projection used in the baseline projection is developed in December of the year preceding the date of the baseline projection. The long-term price track of oil prices is chosen based on the long-term fundamentals of world oil supply and demand. Near-term oil prices, however, are being determined by the political actions of the producing and consuming nations. Consequently, there could be significant interim variation in oil prices through the mid-1990s. It is not inconceivable that prices could swing between $10 and $20 per barrel over this time period. In late 1988, as an example of this near-term variation, prices fell below $15 per barrel on world markets. GRI continues to believe that the fundamentals of oil supply and demand dictate a long-term rise in oil prices.

- Therefore, for purposes of this long-term projection, in the near term, GRI assumes rough stability of the real composite refiner acquisition cost of crude oil (RAC). GRI projects that prices will gradually increase in real terms to slightly over $20 per barrel by 1995. After 1995, real RAC prices increase more rapidly. This reflects a real price escalation supported by a world supply and demand situation in which OPEC's role is projected to become increasingly significant and global supply increasingly tight.

- U.S. production and other non-OPEC Free World sources are falling in this projection. U.S. domestic petroleum production is projected to decline from nearly 10 million barrels per day in 1987 to 6.6 million barrels per day by 2010. OPEC's share of total world production grows from 19 million barrels in 1987 to 26 by 1995, and to 31 million barrels in 2000. At that point, oil prices should begin to escalate more rapidly than general inflation. GRI projects a price of $27 per barrel in real dollars by 2000 and an annual rate of escalation of about 4.6 percent thereafter.

- The real (1987$) and nominal prices in 1987, 1995, 2000, and 2010 are as follows:

Projected U.S. Average Refiner Acquisition Cost of Crude Oil

	Real (1987$)	Nominal (Current$)
1987	17.91	17.91
1995	23.25	32.79
2000	27.00	48.79
2010	42.25	128.57

Natural Gas

- The projected base technology lower-48 gas supply quantities and prices are developed using the GRI Hydrocarbon Model. The advanced technology lower-48 incremental gas quantities and prices are based on analyses done by the GRI Natural Gas Supply R&D group. The prices and quantities of supplements (ANGTS, coal gas, pipeline imports, LNG imports, and SNG from petroleum) are determined based upon current circumstances, announced plans, and other, judgmental considerations.

- The price of lower-48 natural gas also reflects the existing pricing provisions of the Natural Gas Policy Act (NGPA) over the projection period. That is, the various categories of gas under the Act are assumed to be deregulated in accordance with the provisions of existing law and regulation.

Coal

- Delivered coal prices are determined by assumptions concerning productivity, the regional source of coal, mine-mouth coal costs, and rail transportation costs.

- Furthermore, a number of issues, many of which are yet to be resolved, will help to shape coal prices in the future. Included among these issues is continuing excess production capacity in the coal industry, the nuclear "bubble" in the near term that will absorb the bulk of growth in electricity generating needs, the increased "commoditization" of coal that has and will lead to increased spot sales, the advent of clean coal-burning technologies, the restructuring of Western coal royalties that will add 15 to 20 cents to the FOB mine-mouth price, the possibility of acid rain legislation, and, eventually, the need for new capital investment in coal producing capacity and the production infrastructure.

- Representative real (1987$) FOB mine-mouth coal costs between 1987 and 2010 in each of the producing regions are shown in Table 3.

Table 3. Projected FOB Mine-Mouth Coal Costs (1987$/Ton)

	Estimated 1987	1995	2000	2010
Northeast Appalachia[a]				
Low Sulfur	21.84	26.16	28.22	31.40
Medium Sulfur	19.88	22.56	23.48	31.72
High Sulfur	19.36	20.60	21.53	32.80
Northwest Appalachia				
Medium Sulfur	20.39	21.01	22.97	30.98
Central Appalachia[a]				
Low Sulfur	24.62	28.12	30.08	31.44
Medium Sulfur	20.09	23.69	25.44	32.22
Southern Appalachia				
Low Sulfur	27.50	29.87	30.80	33.75
Medium Sulfur	24.93	24.82	27.71	31.98
Illinois Basin				
Low Sulfur	21.94	25.65	28.84	31.80
Medium Sulfur	20.09	21.32	25.24	31.56
High Sulfur	19.47	19.88	22.97	33.42
Western				
Uinta Basin	17.41	21.32	24.62	31.18
Raton Mesa	21.84	24.62	27.71	33.78
Green River	16.38	18.13	20.81	27.44
Powder River-MT	9.48	10.30	12.67	15.26
Powder River-WY	4.53	6.49	7.00	13.10
U.S. Average	20.39	22.56	24.82	30.47

[a] *Coal ranging from 10,500 to 12,500 Btu/lb.*

Nuclear

- The projection assumes only the completion of the nuclear power plants currently under construction less plants that appear to face cancellation. By year-end 1987, 93.7 gigawatts of nuclear generating capacity was in place and operating. Capacity considered to be currently "on order," under construction, or operating was 118 gigawatts.

- Total nuclear nameplate generating capacity grows in the projection as follows:

Nuclear Nameplate Generating Capacity (Gigawatts)

Year	Capacity[a]
1987	90.7
1988	96.5
1989	98.8
1990	100.0
1995	102.6
2000	102.6
2010	96.9

[a] *Projected capacity reflects the average capacity available over a given year and not year-end capacity.*

III. Summary Tables

The 1988 GRI Baseline Projection is summarized in Table 4, which presents U.S. primary energy consumption, and Table 5, which presents energy consumption by sector.

A. Primary Energy

Table 4. 1988 GRI Baseline Projection of U.S. Primary Energy Consumption (Quads)

	Actual 1987[a]	1995	2000	2010
Petroleum	32.9	35.3	37.4	38.9
Gas[b,c]	17.5	18.3	18.6	19.0
(Total Gas Fuels)[d]	(17.6)	(18.6)	(18.9)	(19.4)
Coal	18.0	19.3	20.9	26.2
Nuclear	4.9	6.5	6.7	6.5
Hydro	3.0	3.5	3.5	3.6
Renewables[e]	3.0	3.6	4.3	5.6
Total	79.3	86.5	91.4	99.8

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Excludes synthetic gas from petroleum and coal.*
[c] *The 1987 base year data has been adjusted to reflect transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*
[d] *Total gas fuels includes 0.3 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in each of 1995 and 2000 and 0.4 quad in 2010.*
[e] *Includes wood, solar, direct geothermal heat, etc.*

Total Demand

- Total primary energy consumption is projected to grow from 79.3 quads in 1987 to 99.8 quads in 2010, or at about 1 percent annually or less than one-half (44 percent) of the projected rate of growth in GNP over the long term. The energy intensity of the economy, therefore, is declining throughout the projection, reflecting the continued improvement in the efficiency of energy utilization and continued economic restructuring away from energy-intensive activities.

- The energy-to-GNP ratio, used as a measure of relative energy consumption in comparison with base-year consumption, is projected to fall from 20,700 Btu per 1982 dollar of GNP in 1987 to 15,600 Btu in 2010. This represents a decline in energy intensity averaging 1.2 percent per year over the projection period.

- While the 1988 baseline projection reflects substantial improvement in energy intensity between 1987 and 2010, the rate of improvement varies over the projection. The projection reflects a lower rate of energy conservation in the near term, through 1990, than after 1990. The decline in energy intensity averages 0.7 percent per year between 1987 and 1990 and 1.3 percent per year between 1990 and 2010.

- The slower rate of energy conservation in the near term reflects the impact of relatively low energy prices and the high average utilization rate of currently existing industrial plant, which implies increased use of older, less efficient plant as the current surge in manufacturing continues. After 1990, as energy prices increase more sharply (real crude oil prices are projected to increase at 3.7 percent per year between 1990 and 2010 and gas acquisition prices at over 4 percent per year), energy conservation increases.

- There can be substantial year-to-year variation in the rate of energy use and conservation. Events of 1988 illustrate the potential for this variation. With a relatively cold winter; a warm summer; an extended drought that forced the use of additional oil, gas, and coal to replace hydro generated electric power; and substantial growth in the U.S. manufacturing sector primarily through the greater utilization of existing capacity, the energy intensity of the economy may actually increase in 1988 versus 1987. This is probably not representative of a new long-term trend, but only the confluence of events in a single year that combined to increase energy intensity.

Petroleum

- U.S. petroleum consumption is projected to increase at a rate slightly below that of total energy demand. Primary petroleum consumption grows from 32.9 quads in 1987 to 38.9 quads by 2010. Although about half of the increase occurs in transportation uses, demand growth is also substantial in industrial feedstock uses. Increased use by electric utilities in existing oil-burning facilities and new peaking units is also expected. The growth in electric utility consumption will be largely from increased residual fuel oil consumption.

- Transportation sector consumption of petroleum, largely gasoline and distillate fuel oil, is projected to increase by 3.6 quads between 1987 and 2010. Industrial feedstock consumption of petroleum, dominated by increased petrochemical consumption of feedstocks (liquefied petroleum gases, naphtha, still gas, and other oils), grows by 1.4 quads over the projection. Electric utility consumption of petroleum is projected to increase by 1.3 quads between 1987 and 2010 as available electric generating capacity tightens, implying increased use of available oil-fired capacity.

- Domestic petroleum production is projected to decline from nearly 10 million barrels per day in 1987 to 6.6 million in 2010. Oil imports, therefore, would reach 12.4 million barrels per day by 2010. The growth in oil imports projected in the baseline is consistent with many contemporary projections.

- Included in the substantial growth in oil imports is a large increase in imported petroleum products. Net product imports are projected to grow from 1.3 million barrels per day in 1987, or slightly over 8 percent of total marketed production, to 6.3 million barrels per day by 2010, or to over a 30 percent share of marketed petroleum product supplies.

- If the petroleum products are not available for import from the world markets or if U.S. security concerns prohibit the import of such a large share of petroleum product supplies, the U.S. refinery industry will need to make an enormous investment in new refinery capacity. The increased investment in refineries would strain capital markets and would change relative petroleum product markups. It could also imply increased gas consumption in the electric utility sector, for example, if increased residual fuel oil supplies are not available from either world markets or the new refinery slate.

Natural Gas

- In early 1987 DOE/EIA statistics did not appear to account adequately for the substantial increase in carriage gas sales to the industrial and electric utility sectors. This discrepancy was probably balanced by the rapid increase in "unaccounted-for" gas. In fact, in early 1988 the 1987 DOE/EIA statistics were revised—unaccounted-for gas was reduced and total consumption increased, both substantially. In the revised statistics, unaccounted-for gas equals 4.6 percent of consumption in 1987. This percentage is still higher than any single year dating back to 1973. Thus, it appears that DOE/EIA statistics still do not account adequately for carriage gas sales. Consequently, the 1987 base-year data in the 1988 GRI Baseline Projection was adjusted to better reflect transportation sales of gas. Unaccounted-for gas was reduced by 0.4 quad and industrial consumption increased by 0.4 quad.*

- In direct contrast to the situation in early 1987, DOE/EIA data in early 1988 appears to overestimate carriage gas sales substantially. Unaccounted-for gas for the first 7 months of 1988 is a negative 796 trillion Btu versus a positive 40 trillion Btu (June 1988 MER) in 1987. This suggests that DOE/EIA statistics for early 1988 overstate the growth in gas consumption in 1988 versus 1987.*

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* Immediately prior to printing the *Insights*, DOE/EIA substantially revised the 1987 and 1988 natural gas statistics in the July 1988 Monthly Energy Review. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.

- If the overstatement of gas consumption is adjusted, actual gas consumption still grew substantially in 1988 over 1987 due to both a colder winter and a warmer summer in gas-using areas and the recovery of the U.S. manufacturing sector. Gas has also benefited to some extent from higher than expected gas consumption by electric utilities, which was needed to replace lost hydro generation unavailable in 1988 due to the drought. If these conditions do not persist in 1989, actual gas consumption could fall from the higher than expected 1988 levels of consumption.

- The projection, which does not consider transitory and cyclical short-term effects, does not reflect the large increase in gas consumption in 1988. Gas consumption is projected to average growth of 0.6 percent per year between 1987 and 1995. Primary gas consumption is projected to reach 18.3 quads by 1995. After 1995 growth in gas consumption is projected to gradually slow, largely due to increasing relative gas prices. Between 1995 and 2000, gas consumption is projected to grow at 0.3 percent per year and between 2000 and 2010 at a slower 0.2 percent per year. Primary gas consumption is projected to reach 19.0 quads by 2010.

- While this represents a relatively stable market outlook, it involves shifts between diminishing traditional uses in the industrial and residential sectors and increasing requirements in the electric utility and commercial sectors. Between 1987 and 2010, commercial and electric utility sector gas consumption grows by 2.1 quads and residential and industrial consumption declines by nearly 0.5 quad.

- The projected level of primary gas demand in the 1988 GRI Baseline Projection anticipates the availability of a few selected new gas technologies resulting from GRI's program for which technical characteristics, economics, and market entry dates are reasonably predictable. Furthermore, meeting the gas demand levels is critically dependent upon the availability of advanced gas supply technologies and supplemental gas supply sources. The projection, however, does not reflect the entire potential impact of gas R&D and is in that sense a baseline future for the evaluation of potential R&D strategies.

- The 1988 projection includes no estimate of potential demand for natural gas to serve new environmental functions, such as power plant emission control, waste incineration, or large-scale transportation use. To the extent gas is used in these applications, gas consumption could be higher than projected here.

- The gas total shown in the primary energy total represents only primary gas consumption. The non-additive item, "total gas fuels," includes all gas consumption including that supplied by synthetics. The 1988 projection includes 0.3 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in each of 1995 and 2000 and 0.4 quad in 2010.

Coal

- As is the case in most contemporary projections, coal consumption is projected to grow rapidly in the baseline projection. Primary coal consumption is projected to grow from 18.0 quads in 1987 to 26.2 quads by 2010. This represents a 1.7 percent annual growth rate, which is much more rapid than growth in overall energy demand.

- The predominant increase in coal consumption is in the generation of electricity. Electric utility coal consumption is projected to increase from 15.2 quads in 1987 to 21.7 quads by 2010. The projected increase in electricity demand is below that in many contemporary projections. To the extent electricity demand grows faster, electric utility coal consumption could increase more rapidly.

- The projection also includes significant growth in industrial coal consumption. Industrial coal consumption is projected to grow from 2.7 quads in 1987 to 4.1 quads in 2010. Between 1973 and 1986, industrial coal consumption fell from 4.1 quads to 2.6 quads. In 1987 coal consumption increased slightly and, with the recovery in U.S. manufacturing, industrial coal consumption grew rapidly during the first 6 months of 1988, by over 10 percent (June 1988 MER). The 3.4 percent per year decline in coal consumption between 1973 and 1986 has led some analysts to conclude that industrial coal consumption will not increase in the future. However, the entire decline in consumption was the result of a 7.7 percent per year decline in coking coal consumption over this period as the U.S. steel industry declined. Without this decline, industrial coal consumption was level or slightly increasing. While the baseline projection shows some continued erosion in coking coal consumption, it does not approach the levels experienced in the past. In fact, current consumption levels of coking coal are not high enough to support the quantity of decline that occurred between 1973 and 1986. Without this offset, and with higher relative gas and petroleum prices, particularly after the year 2000, industrial coal consumption is projected to increase significantly in the baseline projection.

- The increasing use of coal will depend upon the availability of coal mining and transportation capacity at prices competitive with other fuels. The baseline projection does not assume any new environmental constraint that would further restrict or impose significant new economic burdens upon the use of coal. If such restrictions are imposed or if coal supplies are unavailable, additional gas and petroleum would be consumed to replace the increased use of coal.

Nuclear

- The projection assumes only the completion of the nuclear power plants currently under construction and the continued operation of those plants that have not been affected by policy restrictions. No new orders for nuclear plants are included in the projection, and some plants currently considered to be "on order" are assumed to be deferred or cancelled.

- At the end of 1987, over 93 gigawatts of nuclear generating capacity are in place and operating. By 2010, the projection includes 97 gigawatts of nuclear generating capacity. Total design capacity including operating plants, those under construction, and those on order totaled 118 gigawatts as of June 1988. The baseline projection assumes that 102.6 gigawatts of this capacity will eventually be operational. All new capacity is projected to be on-line by 1995. The full or partial costs of cancelled plants are added into the ratebase and amortized over the projection time frame.

Hydro

- The projection of hydro consumption is based on existing plans for hydroelectric power published by electric utilities. No additional facilities are added to published plans. As of December 1987, there were plans to build an additional 110 new hydropower units totaling approximately 3.0 gigawatts. This compares with existing capacity in 1987 of 84.9 gigawatts.

- The projection of hydro consumption includes only hydroelectric power owned by central generating electric utilities. Hydroelectric power generation by independent power producers (IPP) that is sold into the electric utility grid is included in the renewable energy total. Total IPP hydroelectric capacity in 1987 was estimated to be 1.1 gigawatts. IPP hydroelectric capacity is projected to grow to 7.5 gigawatts by the year 2010.

Renewables

- Renewable energy includes solar, wood, and "other" energy. "Other" includes IPP hydroelectric, direct geothermal heat, wind, and refuse-derived renewable sources.

- Renewable energy consumption grows steadily, but not dramatically, over the projection. Renewable energy consumption grows from 3.0 quads in 1987 to 5.6 quads by 2010. Most of the renewable energy consumption is wood consumption in the residential and industrial sector.

- Renewable energy consumption is impacted somewhat by the softer near-term energy prices as its rate of growth slows from the 1970s and early-1980s. However, the incentives for renewable energy consumption include many factors in addition to price—tax incentives, aesthetics, social concerns. As a result, changes in these factors have an equal or larger impact on the level of renewable energy consumption.

B. Energy Consumption by Sector

Table 5. 1988 GRI Baseline Projection of U.S. Energy Consumption by Sector (Quads)

	Actual 1987[a]	1995	2000	2010
Residential	9.9[b]	10.3	10.6	11.0
Commercial	6.1[b]	6.6	6.9	8.0
Industrial	23.0	24.8	25.7	27.9
Transportation	21.1	22.7	24.3	25.1
Total Delivered	60.1	64.4	67.5	72.0
Net Losses[c]	19.2	22.1	23.9	27.8
Total Primary	79.3	86.5	91.4	99.8

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Historical Energy Information Administration (EIA) statistics for 1987 do not disaggregate data for the residential and commercial sectors. Actual data for 1987 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.*
[c] *Primarily losses in electrical generation and transmission and coal gasification.*

Residential

- Total residential energy demand is projected to increase at only 0.5 percent per year, from 9.9 quads in 1987 to 11.0 quads in 2010. This is slightly greater than one-half the rate of growth in housing over the period. The modest rate of growth in residential energy consumption reflects an expectation of continued energy conservation, much of which is permanently embedded in new construction practices and in new energy-using equipment available in the marketplace.

- Space heating represents the major portion of residential energy consumption, about 60 percent. Water heating represents an additional 15 percent, space cooling 5 percent, and cooking another 5 percent. The balance of energy consumption in the residential sector is for "other" household appliances, which vary in importance. Energy consumption growth in these "other" household appliances tends to be faster than growth in space heating, cooling, water heating, or cooking.

- Owing to its dominant share of residential energy consumption, space heating receives the major focus of analysis of residential energy consumption. The share of various fuels for space heating in the new home market receives a great deal of the attention. However, the level and mix of future residential energy demand, to a large degree, is not determined by the space-heating fuel shares in the new home market alone. Equally important to change in the level and mix of residential energy consumption is the large replacement market for space-heating systems. In the year 2000, the new home market, including both single-family and multifamily units, is projected to equal 1.8 million units. This compares to a replacement market for space-heating systems of over 3.8 million units in the same year.

Commercial

- Total commercial energy consumption is projected to grow from 6.1 quads in 1987 to 8.0 quads by 2010, or at roughly 70 percent of the 1.8 percent per year growth in commercial square footage. The projected level of commercial energy consumption is somewhat lower in this projection than in previous GRI projections as a result of adopting a new methodology for projecting commercial square footage.

- Commercial square footage is projected to grow from 42.9 billion square feet in 1987 to 64.7 billion square feet by the year 2010. GRI continues to project that the strongest growth in commercial square footage will be in the South and West regions of the United States—in particular, in the South Atlantic states and California.

- As the U.S. population grows older, people will have increased leisure time and health concerns will become greater. The type of building constructed will reflect these trends. The fastest growing building types in the baseline projection are expected to be health facilities and hotels. Also growing faster than the average, particularly after 2000, are restaurants and retail structures.

- Owing to the faster growth in commercial square footage in the warmer South and West, the increasing thermal tightness of new buildings, and the increasing focus on comfort as the population grows older, most of the increased demand is for space conditioning and for inherently electrical services such as lighting and communications. Further, commercial space-conditioning fuel choices are strongly influenced by the cooling component. Of the 1.9-quad growth in commercial energy consumption between 1987 and 2010, 1.1 quads is for lighting and other electrical services and 0.4 quad is for space cooling.

- The natural gas share of total commercial energy demand will depend heavily upon the success of gas cooling and cogeneration technologies under current development. This projection reflects an increase in the gas share of commercial space cooling from 5 percent today to 16 percent in 2010, based mainly upon the penetration of cogeneration; double-effect, direct-fired absorption chillers; and gas-fired heat pumps.

Industrial

- After nearly a decade of steady decline, industrial consumption of energy grew by 3.6 percent in 1987. According to DOE/EIA statistics, the growth has remained strong in early 1988. Through June, industrial energy consumption had increased in 1988 by almost 11 percent relative to the same period in 1987. Low energy prices and a resurgence in the export of manufactured goods has influenced the recent experience.

- Strong growth in four energy-intensive industries has accounted for most of the surge in industrial energy consumption growth in early 1988. The paper and products industry grew by 6.0 percent over the first 6 months of 1988, chemicals and products by 8.1 percent, petroleum products by 3.6 percent, and primary metals by 13.8 percent. Historically, these four industries have accounted for over 60 percent of total industrial energy consumption.

- The 1988 baseline projection does not project continued growth in all of these industries at these high rates over the projection time frame. In fact, the quarterly data seems to suggest that the rapid growth in the primary metals industry, the fastest growing industry, may have peaked in late 1987. The projection, however, does include a continued relatively high rate of growth, averaging 3 percent per year, in the chemical industry between 1987 and 2010.

- As a result, while the baseline projection shows a continued increase in industrial energy consumption, it does not reflect a continuation of the type of increase in energy consumption seen in early 1988. Total industrial production is projected to grow at 2.7 percent per year between 1987 and 2010. Over the same period, total industrial energy consumption is projected to grow from 23.0 quads to 27.9 quads, or at about 30 percent of the rate of growth in industrial production.

Transportation

- Total transportation sector energy consumption is projected to grow from 21.1 quads in 1987 to 25.1 quads by 2010, or at roughly 0.8 percent per year. Transportation sector energy consumption is, of course, dominated by petroleum uses; however, it also includes natural gas consumed by pipelines and some gas demand by methane vehicles for fleet use, particularly after the year 2000.

- The total number of vehicles (including passenger cars, light trucks, and heavy trucks) is projected to grow from 164.9 million in 1987 to 221.4 million by 2010. Included in this growth is an increasing percentage of trucks. Trucks account for 27.8 percent of all vehicles in 1987. This share grows to 38 percent of all vehicles by 2010. The higher percentage of trucks, which have much lower MPG ratings, offsets to some degree the improvement in passenger car MPG. Passenger car stock average MPG is projected to be improved from 19 in 1987 to 24.3 MPG by 2010. Over the same period, truck stock MPG improves from 9.4 to 11.6 MPG.

Losses

- Utility generation of electricity represents an increasing portion of total primary energy consumption over the projection period. It grows from 34.8 percent of total primary energy consumption in 1987 to 39.9 percent in 2010.

- The projected rate of growth in energy consumption by utility generating plants both in aggregate and as a percentage of total primary energy consumption is less than historical norms. This is partially the result of a lower projected growth rate in electricity demand than experienced in historical years and partially the result of an increasing proportion of projected total end-use electricity demand being provided by non-utility generation, including cogeneration and Canadian imports. Primary energy losses in the generation of electricity provided by non-utility generation, unlike the losses normally associated with central-station electricity generation, either are not reflected in the U.S. energy accounts (imports) or are now included in the demand for energy by end-use sectors (cogeneration). Thus, losses shown here are less than would be expected for the level of total end-use electricity consumption if all electricity supplies were provided by domestic utility central power stations.

- If the demand for electricity produced through industrial and commercial cogeneration is included, end-use consumption of electricity grows at 1.8 percent per year between 1987 and 2010, or at almost 80 percent of the rate of GNP over the projection time frame. However, consumption of utility generated electricity only grows at 1.6 percent per year. The percentage of total electricity demand provided by non-utility sources, such as self generators, increases from 7.6 percent in 1987 to 11 percent by 2010.

- U.S. central station power generation and transmission losses net of purchases of Canadian generated electricity and cogenerated electricity increase from 19.3 quads in 1987 to 28.2 quads in 2010.

- Coal conversion losses are 0.1 quad in 2010.

IV. Sectoral Breakdown

The projection of delivered energy consumption by sectors is presented in this section.

A. Residential Energy Consumption

Table 6. 1988 GRI Baseline Projection of Delivered Energy Consumption—Residential Sector (Quads)

	Estimated 1987[a,b]	1995	2000	2010
Petroleum	1.6	1.4	1.3	1.2
Gas	4.5	4.6	4.6	4.4
Coal	0.1	0.1	0.1	0.1
Electricity	2.9	3.3	3.5	3.7
Renewables[c]	0.8	0.9	1.1	1.6
Total	9.9	10.3	10.6	11.0

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Historical Energy Information Administration (EIA) statistics for 1987 do not disaggregate data for the residential and commercial sectors. Actual data for 1987 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.*
[c] *Includes wood, solar, direct geothermal heat, etc.*

Total Demand

- Total residential energy demand is projected to increase from 9.9 quads in 1987 to 11.0 quads in 2010 or at 0.5 percent per year. The modest rate of growth in residential energy consumption reflects an expectation of a continuing decline in energy consumption per housing unit and a slower growth in the size of the housing stock than recent historical experience would suggest. Direct fuel consumption per household (excluding electrical losses) declines from an estimated 107.3 million Btu in 1987 to 98.7 million Btu by 2010.

- A continuing decline in energy consumption per housing unit, however, does not necessarily mean a decline in total residential energy consumption each year. Equally important is the number of homes constructed each year. Residential energy consumption per housing unit has been either relatively flat or declining for the entire period from 1960 to 1987 with the exception of the period from 1965 to 1969. The 1965 to 1969 period corresponds to the strong marketing of all-electric homes and a rapid increase in the saturation of space cooling.

- By contrast, in the 27 years since 1960 total residential energy consumption has fallen year-to-year in only 8 years. Six of these years occurred in the period from 1973 to 1981 and correspond closely to the rise in energy prices over that period. In 1983 total residential energy consumption fell by 2.8 percent in response to an abnormally warm winter in early 1983 and a low level of housing starts during the recession of 1982-83. In 1986 residential total energy consumption fell by a small 0.8 percent in response to warm winter months in January through March.

- Ignoring the period from 1984 to 1987, historical residential energy consumption trends since 1960 can be broken into two periods—1960 to 1972 and 1973 to 1983. Total residential energy consumption grew by 3.6 percent per year between 1960 and 1972. By contrast, between 1973 and 1983 total residential energy consumption declined by 1.6 percent per year. The key issue is whether residential energy consumption in the future will reflect the strong growth of 1960 to 1972 period or the conservation effects of the 1973 to 1983 period.

- The usual presumption is that, with the recent decline in energy prices and the more moderate expected increases in energy prices, at least in the near-term, improvements in energy conservation will abate. The baseline projection does, in fact, reflect a slowing in energy conservation trends in the near term. However, much of the decline in energy consumption per unit of housing is the result of trends in factors impacting residential energy consumption that are embedded in current residential technology practices, building codes, or socioeconomic trends. As a result, the baseline projection does not expect energy conservation improvement to disappear altogether.

- With increasing real energy prices in the 1990s and, particularly, after the year 2000 (electricity prices are projected to increase by 1.9 percent per year, gas by 3.3 percent per year, and distillate fuel oil prices by 3.0 percent per year after the year 2000), energy conservation is projected to accelerate. However, conservation is not projected to increase to the levels experienced during the 1970s. The baseline projection includes an assumption that conservation improvement will be more gradual in the future than it was in response to the energy price shocks of the 1970s. With continued improvement in energy conservation assumed over the entire projection period, even with rapidly increasing energy prices after the year 2000, the projection assumes that there are few dramatic improvements in energy conservation still available.

- As important to the projection of total residential energy consumption as conservation is the projected growth in the stock of homes. Even with strong energy conservation, if the size of the housing stock grows rapidly, total residential energy consumption can also grow. However, U.S. population growth has slowed noticeably in recent years. Much of the recent boom in housing markets has been due to the 1950s baby-boom generation reaching an age where they acquire a home. As fewer people enter the home-buying period of life, the growth in the number of housing units will slow. The baseline projection includes a projected growth in the housing stock of only 0.8 percent per year between 1987 and 2010. This compares with housing stock growth of 1.8 percent per year between 1960 and 1970, 2.4 percent per year between 1970 and 1980, and 2.1 percent per year between 1980 and 1987. The lower rate of growth of the housing stock holds down the growth in total residential energy consumption despite a more modest rate of improvement in energy conservation than experienced in the 1970s.

- A number of events could change this projection dramatically. For example, an unexpected boom in the birth rate (there is, in fact, some evidence today of an upturn in the birth rate as the 1950s baby-boom generation has children at a somewhat older age than their parents), the loosening of immigration quotas allowing a much higher level of population growth due to immigration, or a significant technology breakthrough that lowers energy consumption per housing unit could cause dramatic changes in total energy consumption.

Petroleum

- Residential sector petroleum consumption is projected to decline over the projection time frame. The decrease in petroleum consumption from 1.6 quads in 1987 to 1.2 quads by 2010 reflects a projected steady increase in petroleum prices, particularly distillate fuel oil, and, more importantly, a continued fall in the number and share of oil-heated homes in the housing stock.

- Over the period from 1960 to 1972, residential petroleum consumption in the U.S. increased from 2.3 quads to 2.9 quads or at 2.1 percent per year. However, over this period the number of oil-heated homes, the main use for petroleum in the residential sector, declined from 17 million to around 16.1 million homes. The increase in consumption, despite a decline in the total number of oil-heated homes, was due to a continued increase in the number of oil-heated homes in the South and, more importantly, colder Northeast states. The number of oil-heated homes declined in the Central states and West states as natural gas and electricity gained market share. The larger heating loads in the Northeast offset the loss of load in the Central and West states.

- Starting in 1972, due to increasing oil prices and slow economic and population growth in the Northeast, the growth in the number of oil-heated homes in the Northeast stopped. Further, after 1973 the number of oil-heated homes in the South began to decline. These reversals, combined with the continued decline in the number of oil-heated homes in the Central and West states, led to a steep drop in the number of oil-heated homes from 16.1 million to 13.0 million between 1972 and 1983. The sharp decline in the number of oil-heated homes in combination with improvements in energy conservation resulted in a decline in residential petroleum consumption over this period averaging 7.1 percent per year. Residential petroleum consumption declined from 2.9 quads to 1.4 quads over this period.

- Over the last few years, with softer oil prices and resurgence in economic growth in the Northeast, residential petroleum consumption has firmed and, in fact, slightly increased. However, the number of oil-heated homes in the housing stock has continued to decline from 13.0 million in 1983 to 12.2 million in 1987.

- The projected decline in residential petroleum consumption in the baseline projection reflects an expectation that the number of oil-heated homes will continue to decline in the future. The number of oil-heated homes is projected to fall from 12.2 million in 1987 to 9.7 million by the year 2010. Furthermore, the projection reflects a reversal of the recent decline in oil prices. In particular, real (1987$) distillate fuel oil prices are projected to increase from $5.96 per million Btu in 1987 to $10.44 by 2010. Last, the projection does not expect a continuation of the dramatic economic recovery experienced in the Northeast over the last few years. The projection continues to show more economic growth in the South and West regions of the United States. These three factors combine to reverse the recent short-term recovery in residential petroleum consumption.

Gas

- Residential gas consumption is projected to decline slightly from 4.5 quads in 1987 to 4.4 quads by 2010. However, residential gas demand is projected to increase in the near term as the gas space-heating share of the new single-family home market increases. This is consistent with recent trends in the gas share of the space-heating market. Since 1982 the gas share of the new single-family home market has grown from 40 percent to 52 percent in 1987. This trend is projected to continue, at least in the near-term, and gas demand grows from 4.5 quads in 1987 to 4.7 quads by 1990. After 1990 residential gas demand is projected to decline, despite an increase in the number of gas-heating customers from 54.2 million in 1990 to 67.3 million in 2010. Efficiency improvement in both new and replacement equipment, as well as improvement in the thermal integrity of homes, will more than offset the increase in the number of gas customers.

- Gas consumption in the residential sector is dominated by consumption for space heating. In 1987 gas consumption for space heating represented 76 percent of total gas consumption. The improvement in the gas share of space heating since 1982 has resulted, partially, from the decline in gas prices. However, since 1982, real electric and distillate fuel oil prices have also declined sharply. The increased availability of higher efficiency furnaces has reversed the decline in the gas share of the space-heating market. Since the early 1980s an increasing percentage of the gas furnaces sold in the United States have had average fuel use efficiencies (AFUE) above 80 percent. In 1983, 15.4 percent of the furnaces sold had an AFUE above 80 percent. In 1987 that percentage had grown to 33.0 percent (see Table 7).

Table 7. Sale of Gas Furnaces by Average Fuel Use Efficiency (%)

AFUE	1983	1985	1987
Above 86	7.0	12.2	16.1
80 to 86	8.4	19.0	16.9
71 to 79	4.8	10.4	14.5
65 to 70	53.1	43.5	41.5
Below 65	26.7	14.9	11.0

- The availability of high-efficiency furnaces has not had the same impact on all regions of the United States. In some regions a large percentage of the gas-fired, space-heating systems are hydronic systems (boilers), not furnaces. Boilers are particularly prevalent in New England and the Middle Atlantic states. The efficiency of boilers has not improved to the extent seen in furnaces over the last few years. In regions where boilers are a major portion of the space-heating plant, the replacement decisions, for many people, are based on the available boiler technologies. The efficiency improvement from replacing old boilers is relatively less than experienced when replacing old furnaces. Thus, the energy saving tends to be less and the decision criterion different.

- The expectation for continued efficiency improvement in the future was heightened by the enactment of national appliance efficiency standards in early 1987. The law specifies minimum efficiency standards for gas, electric, and oil-fired appliances. Included under the new standards are space-conditioning systems (both heating and cooling) and other household appliances—water heaters, dishwashers, kitchen ranges, etc.

- The new appliance efficiency standards state that as of January 1, 1992, less than 4 years from now, all new furnaces sold must have an annual fuel use efficiency of not less than 78 percent. The only exception to this rule is that the efficiency will be set between 71 and 78 percent for new furnaces designed to have a fuel input of less than 45,000 Btu per hour (typically used in warmer regions of the country).

- The new standard will drastically change the comparative economics of space heating with gas and other fuels, particularly in regions with relatively small heating loads. Many customers who had previously purchased the lowest first-cost system will be forced to consider the purchase of somewhat more expensive systems.

- Further, there are major venting differences between higher and lower efficiency furnaces, size differences, and warranty differences. If the new appliance efficiency standards are enforced in 1992, it is possible that the new appliance efficiency standards will change, possibly significantly, the comparative economics of selecting space-heating systems.

Electricity

- Residential electricity consumption is projected to grow from 2.9 quads in 1987 to 3.7 quads by 2010, or at 1.1 percent per year. Electricity consumption is projected to grow considerably faster in the near term, through 1995, than in the period after 1995. Between 1987 and 1995, electricity consumption is projected to grow at 1.6 percent per year. Consumption grows at a slower 0.8 percent per year between 1995 and 2010.

- Between 1960 and 1973, residential electricity consumption grew at 8.5 percent per year. Since 1973 residential electricity consumption has grown at a much slower 3.0 percent per year. Further, in each of the 5-year periods starting in 1965 the growth rate of residential electricity consumption has fallen. In the period from 1965 to 1970, residential consumption grew at almost 10 percent per year. By comparison, in the period from 1980 to 1985 consumption growth fell to 2.0 percent per year. Given these trends and other factors—declining population growth rates, expectations of lower home construction rates, continuing conservation trends, and the attainment of maximum saturation in residential cooling—it has become fashionable to predict lower growth rates in residential electricity consumption and, also, in total electricity consumption in the future.

- While few data are available, the data for just the last few years suggest that residential electricity consumption may have begun to trend upward again. Since 1985, residential electricity consumption has grown more rapidly in each succeeding year. In 1986 consumption grew at 3.0 percent, in 1987 at 3.9 percent, and during the first 6 months of 1988 at 4.4 percent. In fact, many recent forecasts have underestimated the rate of near-term growth in electricity consumption. The North American Electric Reliability Council (NERC) forecast for aggregate electricity demand underestimated growth in 1986 by 0.4 percent and in 1987 by 2.4 percent. Both the 1986 and 1987 GRI Baseline Projections underestimated first-year residential electricity consumption growth—by 0.8 percent in 1986 and by 2.3 percent in 1987. The EIA Annual Energy Outlook underestimated residential electricity consumption growth in 1987 by 1.7 percent and estimated growth in 1988 of 2.8 percent, compared with actual growth in the first 6 months of 4.4 percent.

- The baseline projection essentially uses a process approach to project energy consumption in both the residential and commercial sectors. It looks at the energy consumed by service given a number of pieces of equipment using gas, electricity, etc. Concern over the difference between the near-term projected level of electricity consumption and the actual levels led to an examination of the details of the projection for inconsistencies. An examination of projected growth in electric service for space heating, space cooling, and water heating by comparing the existing equipment stock, the load levels for each service, and the potential growth in the stock of equipment suggested that the projection for these services is reasonable. This implies that, if actual electricity demand growth is higher than projected, this growth is supported by growth in "other" uses (e.g., refrigerators, home freezers, cooking, clothes dryers, clothes washers, dishwashers, lighting, other small appliances) that is higher than GRI and other analysts are forecasting. The 1988 baseline projection shows electricity consumption for "other" uses growing at 2.3 percent between 1987 and 1995 and at 1.6 percent between 1995 and 2010. To the extent that electricity consumption for these applications grows faster or other new applications are added, electricity demand could grow faster than that projected in the baseline projection.

- This has important implications for natural gas and energy markets in general. For natural gas, higher levels of electricity demand would imply higher levels of utility energy consumption, which offers a potential market for increased gas consumption. If growth in electricity consumption is considerably higher than we are projecting, it could also imply higher electricity prices, which would have an obvious implication for gas/electric price competition.

- Growth in electricity demand also has implications for the electric utility industry. If electricity demand growth rates are higher than those projected here and in other forecasts, the electric utility industry might need to add generating capacity much more quickly than consistent with lower levels of electricity consumption growth. For example, if residential electricity demand grew at 2.3 percent per year between 1987 and 2010, this would increase residential electricity requirements by 1.2 quads or by 30 percent over what the baseline projection shows. By itself, this would increase electric utility capacity requirements by approximately 90 gigawatts.

Renewables

- Residential sector renewable energy consumption includes wood and solar energy. Wood is consumed mostly for space heating, both as a primary and secondary fuel. The baseline projection only includes active solar energy systems used for space heating and water heating. The 1988 GRI Baseline Projection does not include an estimate of photovoltaics. The projection of wood renewable energy consumption is based on homes using wood as the main heating fuel. The projection of solar energy consumption is based on estimated shipments (square feet) of solar equipment.

- Residential renewable energy consumption is projected to grow at a rate of 2.8 percent per year between 1987 and 2010, from an estimated 0.8 quad in 1987 to a projected 1.6 quads by 2010.

B. Commercial Sector Energy Consumption

Table 8. 1988 GRI Baseline Projection of Delivered Energy Consumption—Commercial Sector (Quads)

	Estimated 1987[a,b]	1995	2000	2010
Petroleum	1.0	1.0	1.0	1.0
Gas[c]	2.4	2.6	2.7	3.0
Coal	0.1	0.1	0.1	0.1
Electricity	2.6	2.9	3.1	3.9
(Cogenerated Electricity)[d]	(e)	(0.1)	(0.2)	(0.2)
Renewables[f]	—	—	—	—
Total	6.1	6.6	6.9	8.0

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Historical Energy Information Administration (EIA) statistics for 1987 do not disaggregate data for the residential and commercial sectors. Actual data for 1987 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.*
[c] *Includes gas consumed in commercial cogeneration.*
[d] *Energy consumed to produce cogenerated electricity has already been included in the totals for gas.*
[e] *Less than 0.05 quad.*
[f] *Includes wood, solar, direct geothermal heat, etc.*

Total Demand

- The commercial sector is, today, the smallest of the energy-consuming sectors. In 1987 the commercial sector accounted for only slightly over 10 percent of total delivered energy consumption to the end-use sectors (i.e., the residential, commercial, industrial, and transportation sectors). However, the commercial sector is projected to be one of the fastest growing energy demand sectors. Energy consumption is projected to increase by over 30 percent between 1987 and 2010. This is second only to the over 45 percent growth in energy consumption projected for the electric utility sector. Total commercial sector energy consumption is projected to grow from 6.1 quads in 1987 to 8.0 quads by 2010.

- The driving force behind the high rate of growth in total commercial energy consumption is the projected rapid growth in commercial square footage as the service economy becomes more important in the United States. Commercial square footage is projected to grow at 1.8 percent per year from 42.9 billion square feet in 1987 to 64.7 billion square feet by 2010. This compares with the slower 0.8 percent per year growth rate in the number of residential housing units. The high rate of square footage growth in the commercial sector offsets continued strong conservation trends in the sector. Total delivered fuel per commercial square foot is projected to decline from 141.7 thousand Btu to 123.7 thousand Btu by 2010.

- Currently, the major share of commercial energy consumption is for space conditioning. In 1987 space conditioning (both heating and cooling) accounted for 67 percent of commercial energy consumption. By 2010 space conditioning is still expected to account for 57 percent of commercial energy consumption. The decline in the space-conditioning share of total commercial energy consumption is the result of an increase in energy consumption for lighting, communications, and other applications, many which are inherently electrical. The shares of the two dominant commercial sector fuels—natural gas and electricity—reflect the changing energy applications. In 1987, electricity accounts for 42 percent of commercial energy consumption and natural gas for 39 percent. By 2010, electricity is projected to account for 48 percent of commercial energy consumption and gas for 38 percent.

- The square footage growth rate by region and by building type are important determinants of the mix and level of commercial sector energy consumption. The baseline continues to project above average growth in commercial square footage in the South and West parts of the United States, in particular, in the South Atlantic states and California. Total commercial square footage is projected to grow by 22 billion square feet between 1987 and 2010. The South and West regions, which account for roughly 50 percent of total commercial square footage in 1987, are projected to account for almost 70 percent of this growth, or 14.5 billion square feet. The larger cooling loads encountered in the South and West bias equipment and fuel selection to those that can provide space cooling. This emphasizes the importance of cogeneration and advanced gas-cooling equipment to the natural gas industry.

- As the U.S. population grows older, people will have increased leisure time and health service requirements will become greater. The type of building constructed will reflect these trends. The fastest growing building types in the baseline projection are expected to be health facilities and hotels. Health facility square footage grows at 2.3 percent per year and hotel square footage at 3.0 percent per year. Also growing faster than the average, particularly after 2000, are restaurants and retail structures.

Petroleum

- Since 1960 commercial petroleum consumption has gone through a complete cycle. Between 1960 and 1973, petroleum consumption grew steadily from 1.2 quads in 1960 to 1.6 quads in 1973. After 1973 commercial petroleum consumption declined through 1982 to 1.0 quad and then remained roughly steady through 1987. While the level of aggregation in Table 8 does not show a decline, commercial petroleum consumption is projected to decline gradually over the projection. At a more precise unit of measure, trillion Btu, there is a slow but steady decline in commercial sector petroleum consumption from approximately 1050 trillion Btu in 1987 to 950 trillion Btu by 2010.

- Almost all of the petroleum consumption in the commercial sector is for space heating and water heating, most for space heating. Commercial sector petroleum consumption is dominated by distillate and residual fuel oil consumption. In 1987 these two products account for almost 80 percent of total petroleum consumption. Other petroleum products used in the commercial sector in significant quantities include gasoline, kerosene, and liquefied petroleum gases.

- Residual fuel oil is largely used in larger, older buildings in urban areas. It is common in areas where gas is not available or conversion to gas or other fuels is not feasible. Due to environmental concerns and increasing cost, residual fuel oil consumption in the commercial sector declined sharply during the late-1970s and in the early-1980s. Since 1983 it has been relatively constant. The 1988 projection expects residual fuel oil consumption to remain constant at roughly 0.2 quad through 2010.

- Historical distillate fuel oil consumption in the commercial sector dating back to 1960 has not shown any discernible trend or pattern. Consumption over this period has fluctuated between 0.4 and 0.7 quad. Most new growth in the commercial sector using petroleum would use distillate fuel oil. Commercial square footage using petroleum for space heating is projected to grow from 10.9 billion square feet in 1987 to 13.6 billion square feet by 2010. However, over the same period, as a result of the replacement of old equipment, the average efficiency of petroleum-fired space-heating systems improves from 68 to 78 percent. The growth in square footage is not great enough to offset the improvement in efficiency. As a result, the baseline projects that commercial distillate fuel oil consumption will decline gradually over the projection from 0.6 to 0.4 quad by 2010.

- Petroleum prices offer more than an adequate incentive for continued efficiency and building thermal integrity improvement over the projection time frame. Real (1987$) distillate fuel oil prices, for example, are projected to increase at almost 3 percent per year between 1987 and 2010, or from $4.83 per million Btu to $9.28. As a consequence, petroleum is projected to represent a decreased proportion of total commercial energy consumption over the projection.

Gas

- From 1960 to 1973 commercial gas consumption grew rapidly, increasing from 1.1 quads to 2.7 quads or at 7.2 percent per year. After 1973, as a result of the rapid energy price increases during the 1970s and due to conservation, growth in commercial gas consumption stopped. Since 1973 commercial gas consumption has remained at roughly 2.5 quads per year. It has fluctuated around this amount as relative prices and weather conditions have changed.

- Over the same period, electricity consumption has grown steadily in the commercial sector. The steady growth in electricity consumption is attributable to growth in inherently electrical services (e.g., lighting) and the dominant position space cooling holds in the energy decision in the commercial sector. Measured by square footage, electricity currently meets over 95 percent of the commercial space-cooling requirements. Gas provides the balance of commercial cooling requirements.

- Space-cooling is the driving factor in the space-conditioning fuel choice in the commercial sector. Because of gas's relatively small share of commercial space-cooling markets, the commercial sector represents a potential growth market for natural gas. Gas consumption is projected to grow from 2.4 quads in 1987 to 3.0 quads by 2010 in the 1988 GRI Baseline Projection.

- The achievement of this potential growth is heavily dependent upon the success of gas cooling and cogeneration technologies. The 1988 projection anticipates the impact of some selected technologies that are expected to result from the GRI program. Three emerging gas technologies—packaged cogeneration systems, heat pumps, and double-effect, direct-fired absorption chillers—were included in the projection of the commercial sector.

- These three technologies account for 520 trillion Btu of the projected growth in commercial gas consumption between 1987 and 2010. Without the contribution of these technologies, commercial gas consumption would remain relatively flat over the projection, increasing from 2.4 quads in 1987 to 2.5 quads by 2010. This dramatically highlights the importance of these technologies for gas consumption in the commercial sector.

- Cogeneration accounts for most of the impact, increasing annual gas consumption by almost 400 trillion Btu by the year 2010. On aggregate, the projection includes approximately 440 trillion Btu of gas-fired commercial cogeneration in 2000 and 660 trillion Btu in 2010. However, cogeneration displaces some direct gas consumption that would otherwise occur without cogeneration. Thus, the net increase in gas consumption attributable to cogeneration is somewhat less than the aggregate input for cogeneration. Gas heat pumps add an additional 80 trillion Btu. Gas-fired chillers provide a smaller 40 trillion Btu.

- The introduction of three new gas technologies that can provide space-cooling services (cogeneration is used for space cooling both directly through the use of thermal output and indirectly through the use of generated electricity) improves gas competition for space-cooling services. In 1987 natural gas was used for space cooling in 1.5 billion square feet of the 29.2 billion commercial square feet that were space-cooled. With the contribution of these technologies, by the year 2010, gas is used in 8.5 billion square of commercial floor space, capturing over a 16 percent share of commercial space cooling.

Electricity

- Total commercial electricity consumption is projected to increase from 2.6 quads in 1987 to 4.1 quads by 2010 or at 2.1 percent per year. The 4.1 quads in 2010 includes 3.9 quads of electric power purchased from electric utilities and 0.2 quad produced by cogeneration. The projection assumes that all of the commercial cogeneration is gas-fired.

- Commercial electricity consumption for space heating and cooling is projected to grow slower than electricity consumption for water heating, lighting, and "other" services. Electricity consumption for space heating and cooling is projected to grow at 1.8 percent per year between 1987 and 2010, while consumption for the remaining services is projected to grow at a faster 2.4 percent per year. The lower rate of growth for electrical space heating and cooling reflects slowing space-cooling saturation rates, competition for space-cooling services from natural gas, and rapid efficiency improvements in both heating and cooling equipment. Electricity consumption for the remaining services generally parallels the growth in commercial square footage. However, electricity consumption for "other" services is projected to grow somewhat faster than the rate of growth in commercial square footage. Growth in electricity for "other" services averages almost 4 percent per year. This reflects the rapid adoption of computers and other electronic equipment into the commercial sector.

- Between 1960 and 1973, commercial electricity consumption grew at 8.2 percent per year. Between 1973 and 1986, it grew at a slower 3.8 percent per year. As was the case in the residential sector, it has become fashionable in recent years to predict lower growth rates in commercial electricity consumption in the future, largely based on this downward trend.

- However, recent statistics suggest that commercial electricity consumption may actually be trending upward or, at the very least, leveling off at a rate of growth much higher than the 3.8 percent average experienced since 1973. In 1984 commercial electricity consumption grew by 5.8 percent, in 1985 by 5.1 percent, in 1986 by 4.5 percent, in 1987 by 4.7 percent, and in the first half of 1988 by 6.4 percent. The baseline projection includes an increasing share of space cooling provided by natural gas. This is one explanation for the projected relatively low level of electricity consumption growth in the commercial sector of the baseline projection. However, even if this demand were captured by electricity, it would only increase electricity demand by 0.2 quad. This would increase the growth rate of electricity demand between 1987 and 2010 from 2.1 percent to 2.2 percent. This is still considerably below recent historical growth rates for commercial electricity consumption. As pointed out in the residential sector, future commercial electricity demand growth could be considerably higher than most of the contemporary forecasts, including the GRI baseline projection, are now suggesting.

- The key issues for analysis are to determine the end use of the increased amount of electricity consumption in recent years and to determine if this increased consumption is sustainable. Much of the high rate of growth prior to 1973 was driven by increasing space-cooling saturation rates. That has not been the case in recent years. Obviously, the high rates of economic growth over the last 5 years, particularly in service industries, has contributed to increased commercial electricity consumption. Other potential contributors include tighter buildings, which have higher cooling loads; the adoption in many offices of computer systems, which generate their own heating loads and, in turn, require cooling; and the use of new electrical equipment (e.g., computers, communications devices, etc.) in commercial buildings, which increase electrical demand.

- Again, as was pointed out in the residential sector, if this higher rate of growth is sustainable, the impact for electric utilities and for the demand for other energy sources could be very large. For example, if growth in commercial electricity consumption between 1987 and 2010 averages 3.0 percent per year as opposed to the 2.1 percent projected in the baseline projection, commercial electricity requirements would increase by 0.9 quad by 2010 or by almost 25 percent. By itself, this would increase electric utility capacity requirements by approximately 75 gigawatts by 2010. This is an increase above what is already projected in the baseline, which already exceeds current electric utility plans.

Renewables

- Commercial sector renewable energy consumption includes wood and solar energy. The projection of wood renewable energy consumption in the commercial sector is calculated as a fixed percentage of projected wood consumption in the residential sector consistent with the historical relationship between consumption in these two sectors. The projection of solar energy consumption is based on estimated shipments (square feet) of solar equipment.

- Renewable energy consumption plays a very small role in the commercial sector—in fact, at the level of detail presented in Table 8 it does not even round to 0.1 quad. Commercial solar consumption is projected to grow from 3.9 trillion Btu in 1987 to 19.8 trillion Btu by 2010. Wood consumption is projected to grow from 15.5 trillion Btu in 1987 to 28 trillion Btu by 2010.

C. Industrial Sector

Table 9. 1988 GRI Baseline Projection of Delivered Energy Consumption—Industrial Sector (Quads)

	Actual 1987[a]	1995	2000	2010
Petroleum	8.3	8.8	9.2	9.6
Gas[b,c]	7.3	7.5	7.1	6.9
Coal	2.7	2.8	3.1	4.1
Electricity	2.9	3.5	3.8	4.4
(Cogenerated Electricity)[d]	(0.4)	(0.5)	(0.6)	(0.8)
Renewables[e]	1.8	2.2	2.5	2.9
Total	23.0	24.8	25.7	27.9

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Includes gas consumed in industrial cogeneration.*
[c] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*
[d] *Energy consumed to produce cogenerated electricity has already been included in the totals for gas, petroleum, and coal consumption. This represents cogenerated electricity used by the industrial sector.*
[e] *Includes wood, waste, solar, direct geothermal heat, etc.*

Total Demand

- The trends in total industrial energy demand are distorted somewhat because feedstock uses of petroleum, gas, and coal and metallurgical coal demand are included in Table 9 along with fuel and power uses. A discussion of industrial fuel and power consumption trends is provided following Table 11.
- Table 10 details the projection of industrial feedstock energy consumption.

Table 10. 1988 GRI Baseline Projection of Industrial Feedstock Consumption (Trillion Btu)

	Estimated 1987	1995	2000	2010
Natural Gas	550.8	498.3	465.6	400.0
Coking Coal	806.7	730.5	729.2	726.7
Petroleum	3,334.0	3,766.3	4,081.1	4,762.7
Asphalt and Road Oil	(1,096.2)	(1,208.7)	(1,286.9)	(1,437.3)
Lubes and Waxes	(209.4)	(243.4)	(268.6)	(320.2)
Petroleum Coke	(102.7)	(105.3)	(106.9)	(110.0)
Special Naphthas	(137.5)	(148.3)	(155.8)	(169.9)
Other Petroleum Products[a]	(-119.9)	(-112.9)	(-108.5)	(-84.3)
Petrochemical Feedstocks	(1,908.1)	(2,173.5)	(2,371.4)	(2,809.6)
Total	4,691.5	4,995.1	5,275.9	5,889.4

[a] *Due to inconsistencies in the classifications of some petroleum products, refinery inputs exceed total product supplied, leaving a net negative balance.*

Total Feedstock Demand

- Industrial feedstock energy consumption includes natural gas, petroleum, or coal-derived raw materials used as inputs in the production of intermediate or final products for consumption, such as ethylene produced in an olefins plant using petroleum gases, naphtha gas oils, LPG, or NGL used to make plastics, solvents, detergents, antifreeze, and rubber.

- Of the total industrial energy consumption of 23.0 quads in 1987, roughly 20 percent of the consumption, or 4.6 quads, was for feedstocks. Natural gas accounts for approximately 0.6 quad, coking coal 0.8 quad, and petroleum 3.3 quads. Total feedstock consumption is projected to grow to 5.9 quads by 2010, or at 1.0 percent per year. The baseline projection shows a gradual decline in feedstock energy consumption per dollar of GNP as other segments of the U.S. economy (services, less energy-intensive manufacturing industries, etc.) become relatively more important. Feedstock energy consumption per dollar of GNP is projected to decline from 1.3 thousand Btu per 1982 dollar of GNP to 0.9 thousand Btu by 2010.

Petroleum

- Petroleum products consumed as feedstocks include asphalt and road oil, lube oils and waxes, petroleum coke, special naphthas, and petrochemical feedstocks. Asphalt and road oil, and petrochemical feedstocks account for the majority of petroleum feedstock consumption.

- Asphalt and road oils are used primarily in the construction of roads. In the baseline projection, they are estimated based on a functional relationship with GNP. Asphalt and road oil feedstock consumption is projected to grow from 1.1 quads in 1987 to 1.4 quads by 2010.

- Petrochemical feedstocks are used in the manufacture of chemicals, synthetic rubber, and a variety of plastics. Growth in petrochemical feedstocks is projected based on a relationship with the industrial production index for the chemical industry (SIC 28).

- Petrochemical feedstocks are derived from two sources—from petroleum refineries and from gas separation plants. The refinery input to petrochemical feedstocks (petroleum gases, naphtha gas oils, and aromatic fractions) accounts for about 4 percent of the volumetric output from petroleum refineries. Liquefied petroleum gases and natural gas liquids produced in a gas separation plant, the other petrochemical feedstocks, account for roughly 8 percent of the volumetric output of a natural gas separation plant.

- Petrochemical feedstocks are projected to be one of the fastest growing components of feedstock energy consumption. They are projected to grow from 1.9 quads in 1987 to 2.8 quads by 2010 or at 1.7 percent per year. This is more than double the rate of growth in total industrial energy consumption.

- Total industrial petroleum feedstock consumption is projected to grow from 3.3 quads in 1987 to almost 4.8 quads by 2010 or by 1.5 quads. Projected growth in petrochemical feedstocks account for almost two-thirds of the growth in petroleum consumption for feedstocks between 1987 and 2010.

Gas

- Natural gas feedstocks are used in the production of ammonia, methanol, hydrogen, carbon black, and in heat-treating atmospheres. The feedstock projection in the baseline does not account for gas used in heat-treating atmospheres.

- The natural gas used as feedstocks coming out of a separation plant tends to be 1000 Btu gas as opposed to the higher Btu gas consumed by end-users. The LPG and NGL mentioned earlier, which are also derived in natural gas separation plants, are not considered to be natural gas but petroleum products. Thus, to the extent LPG and NGL are used as feedstocks, this is counted as petroleum feedstocks.

- Much of natural gas use for feedstocks is in the production of fertilizers. Owing to the competitive disadvantage of U.S. fertilizer producers, this use is projected to decline in the future. As a result, natural gas consumption for feedstocks is projected to decline from 0.6 quad in 1987 to 0.4 quad by 2010.

- A feedstock use of natural gas with a large potential is the production of methanol for transportation fuels. Currently, the economics of methanol as a transportation fuel do not compare favorably with oil prices. However, if regulation over environmental concerns promoted the use of methanol, natural gas consumption as a feedstock could grow significantly in the future.

Coal

- Coking coal is used primarily in blast furnaces for smelting ores. Coking coal consumption in the industrial sector fell dramatically between 1973 and 1986 as a result of the decline in the U.S. steel industry. Despite the recent surge in the U.S. steel industry, the baseline projects at best a stagnant steel industry over the projection time frame. Between 1987 and 2010, the primary metals industry is projected to grow at an average annual rate of 0.4 percent. In response to this slow growth in the steel industry, the baseline projection shows continued erosion in coking coal consumption. However, the decline is not nearly as sharp as what occurred in the 1970s when the absolute level of production in the steel industry declined. Coking coal consumption is projected to decline from 0.8 quad in 1987 to 0.7 quad by 2010.

D. Industrial Fuel and Power Energy Consumption

Table 11. 1988 GRI Baseline Projection of Industrial Fuel and Power Consumption[a] (Quads)

	Actual 1987[b]	1995	2000	2010
Petroleum	4.9	5.0	5.1	4.8
Gas[c,d]	6.7	7.0	6.7	6.5
Coal	1.9	2.1	2.4	3.4
Electricity	2.9	3.5	3.8	4.4
(Cogenerated Electricity)[e]	(0.4)	(0.5)	(0.6)	(0.8)
Renewables[f]	1.8	2.2	2.5	2.9
Total	18.2	19.8	20.5	22.0

[a] *Excludes industrial raw material and feedstock consumption of energy.*
[b] *Actual 1987 data estimated based on GRI projections of feedstock energy consumption in the industrial sector and total industrial energy consumption data. Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[c] *Includes gas consumed in industrial cogeneration.*
[d] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*
[e] *Energy consumed to produce cogenerated electricity has already been included in the totals for gas, petroleum, and coal consumption. This represents only cogenerated electricity used in the industrial sector.*
[f] *Includes wood, waste, solar, direct geothermal heat, etc.*

Total Demand

- Industrial energy consumption declined in 6 of the 7 years between 1980 and 1986. The strongest decline occurred in the recession year of 1982 (over 11 percent), but consumption also declined in nonrecession years. Consumption declined, first, in response to the restructuring of the U.S. manufacturing sector and, second, due to the fall in U.S. exports as the U.S. dollar strengthened relative to other currencies. With a weaker dollar in 1987, U.S. manufacturing growth spurted ahead and the trend in energy consumption reversed. Total industrial energy consumption (including both feedstock and fuel and power energy consumption) grew by 3.6 percent in 1987 and grew at a faster 4.9 percent in the first 6 months of 1988 (after correction for DOE/EIA's incorrect handling of transportation gas sales*). As a result, many forecasts are now predicting the start of a new period of economic and energy growth in the U.S. industrial sector. At issue is whether the changes of the past year and one-half represent a permanent reversal of recent trends or just a temporary phenomenon.

- From 1960 to 1972, U.S. industrial production grew at an average rate of 5.0 percent per year. Over this period, capacity utilization rates tended to be high and both old and new plants were used extensively. Energy consumption over this period grew an average rate of 2.9 percent per year. Thus, even during a period of relatively low energy prices, industrial sector energy conservation tended to be high as growth in output clearly outstripped growth in energy consumption used to produce that output. Starting with the energy price spike of 1973, the pattern of industrial production and energy consumption changed dramatically. Over the period from 1973 to 1987, U.S. industrial production grew at an average rate of 2.3 percent per year. With the closing of older, less energy-efficient plants and strong incentives for energy conservation, annual energy consumption declined at an average rate of 1.5 percent per year over this period.

- Many of the factors that led to the sharp decline in industrial energy consumption between 1973 and 1987 were one-time events—the closing of older, less-energy efficient plants, the purchase and adoption of new equipment designed with the higher energy prices of the 1970s in mind, and the movement overseas of parts of the U.S. manufacturing industry when economics were more favorable outside of the United States (e.g., lower labor costs for the textile industries). These events will probably not take place again, so the rate of future conservation should not approach the high levels seen during the 1973 to 1987 period.

- However, the driving force behind industrial energy consumption is the rate of industrial production growth. The historical average growth rate of industrial production since the end of World War II has only been 3.8 percent. With the exception of an upturn in the 1960s due to strong growth over the years from 1962 to 1966, the rate of growth in industrial production has declined in each decade since World War II.

- If we assume that future industrial energy conservation will more closely resemble the period from 1960 to 1972, then this implies that economic growth must occur at a rate of 2.5 to 3.0 percent per year if industrial energy consumption is to remain even constant. A weaker U.S. dollar encouraging increased exports could produce a rate of growth in excess of 3 percent per year. However, a weaker dollar would make it difficult to finance the U.S. budget deficit. Furthermore, the continuing decline in U.S. population growth rates does not support the type of industrial production growth seen during the 1960s. As a result, the 1988 baseline projection does not anticipate continued industrial production growth at the levels seen in 1987 and early 1988. Total industrial production is projected to grow at approximately 2.7 percent per year between 1987 and 2010. Much of the industrial energy consumption growth is for feedstock energy consumption. As a result, total industrial fuel and power energy consumption is projected to grow at a slow 0.8 percent per year, or from 18.2 quads in 1987 to 22.0 quads by 2010.

- While the 0.8 percent rate of growth in energy consumption is modest, it represents a slower rate of energy conservation than occurred during the 1960 to 1972 period. Further, this modest rate of energy consumption growth occurs during a period when projected energy prices rise at rates that correspond much more closely to the increases seen during the 1973 to 1987 period than during the period from 1960 to 1972. For example, between 1987 and 2010, crude oil prices are projected to increase at 3.8 percent per year. This suggests that the potential exists for even more energy conservation in industrial energy consumption than is projected in the baseline.

Petroleum

- Industrial fuel and power consumption of petroleum products grew relatively steadily from 1960 through 1979. There was, of course, some variation due to recessions and there was a downturn following the first oil price spike in 1973, but consumption generally grew steadily reaching 6.2 quads by 1979. Seventy-five percent of the consumption in 1979 was accounted for by still gas, distillate fuel oil, and

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* Immediately prior to printing the *Insights*, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 Monthly Energy Review. The revised data better accounts for transportation sales of natural gas. With the revised statistics, total industrial energy consumption over the first 7 months of 1988 grew at only 3.1 percent. The new data will be adopted in subsequent baseline projections.

residual fuel oil. Starting with the second oil price spike in 1979, industrial fuel and power consumption of petroleum declined sharply. Fuel and power consumption of petroleum fell from 6.2 quads in 1979 to 4.5 quads by 1983. A decline in residual fuel oil consumption accounted for almost 50 percent of this drop.

- After 1983 with falling oil prices and, in recent years, with increased industrial production, industrial fuel and power consumption of petroleum has grown slowly but steadily, reaching 4.9 quads in 1987. Much of the growth in 1987 and early 1988 is due to the resurgence of industrial production due to the increased export of U.S. manufacturing goods. However, over this period residual fuel oil consumption has continued to decline, falling from 0.9 quad in 1983 to 0.7 quad by 1987. At least part of this decline can be explained by the more flexible nature of natural gas pricing in recent years.

- The 1988 GRI Baseline Projection reflects a continuation of these recent trends. However, the projection does not expect industrial production to continue to grow at the rapid rates seen in 1987 or early 1988. Industrial production is projected to grow at 2.8 percent per year between 1987 and 1995. Over this same period, petroleum consumption for fuel and power is projected to grow only slightly from 4.9 quads in 1987 to 5.0 quads by 1995, or at 0.3 percent per year. This compares with growth in total industrial fuel and power consumption of 1.1 percent per year over the same period.

- The entire growth in petroleum fuel and power consumption between 1987 and 1995 is accounted for by a reversal of the recent trend in residual fuel oil consumption. Residual fuel oil consumption grows from 0.7 quad in 1987 to 1.2 quads by 1995. This reflects increasingly competitive residual fuel oil prices, particularly with natural gas, as gas prices adjust to the end of the gas bubble. However, it also reflects, at least partially, the current baseline projection methodology. The model uses a simple markup approach and does not reflect volumetric adjustments of residual fuel oil prices. To the extent that there are volumetric adjustments in residual fuel oil prices, consumption of residual fuel oil could be lower and gas consumption could be somewhat higher than projected here.

- After 1995, industrial fuel and power petroleum consumption is projected to continue to grow slowly to 5.1 quads by 2000 before falling to 4.8 quads by 2010. The decline after the year 2000 reflects strong price competition from coal. Both natural gas and petroleum suffer from price competition with coal after 2000. After 2000 residual fuel oil prices are projected to grow by 4.4 percent per year. Coal prices are projected to grow by a much slower 1.6 percent per year. The ratio of residual fuel oil to high-sulfur coal prices reaches 3.25 by 2010. This compares with a ratio of 1.80 in 1987. With the large price advantage of coal over residual fuel oil, the projection assumes that industrial energy consumers use coal despite the many noneconomic concerns about coal consumption.

Gas

- Industrial fuel and power consumption of natural gas fell sharply and steadily between 1973 and 1983 in response to conservation induced by higher gas prices and low industrial production growth rates. Between 1973 and 1983, industrial fuel and power consumption of natural gas fell from an estimated 9.9 quads to 6.3 quads. Natural gas consumption for fuel and power turned up in 1984 in response to the economic recovery following the 1982-1983 recession and continued to grow in 1985. However, in 1986 gas consumption declined sharply as natural gas prices did not adjust rapidly enough to the fall in crude oil prices below $10 per barrel. Fuel and power consumption of natural gas fell to 6.2 quads in 1986.

- In the *Insights* article summarizing the 1987 GRI Baseline Projection, we predicted that natural gas would regain by 1990 the fuel-switchable markets lost in 1986 to residual fuel oil. In fact, natural gas regained the markets lost in 1986 to residual fuel oil by late 1987. Natural gas consumption for fuel and power rebounded to 6.7 quads in 1987. Natural gas consumption has continued to grow in early 1988. Over the first 6 months of 1988, industrial gas consumption increased by 7.8 percent (after correction for DOE/EIA's incorrect handling of transportation gas sales*).

- Gas' ability to recover the market share lost in 1986 reflects, at least in part, the increased flexibility of gas prices. The increased use of spot and transport gas sales has reduced the lag time that gas

* Immediately prior to printing the *Insights*, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 Monthly Energy Review. The revised data better accounts for transportation sales of natural gas. With the revised statistics, industrial gas consumption over the first 7 months of 1988 grew by only 2.6 percent. The new data will be adopted in subsequent baseline projections.

prices have traditionally shown in adjusting to changes in competing fuel prices. This suggests that in the future there should be less fuel switching due to market-driven declines in competing fuel prices, if adequate gas supplies are available. In effect, natural gas sellers have become more sophisticated about the market. This has important implications for future market competition. A key factor in determining future levels of gas demand is the ability of gas to compete with residual fuel oil and coal in the price-sensitive fuel and power markets.

- With the recovery in 1987 of industrial gas demand for fuel and power, gas represented about 37 percent of total industrial fuel and power consumption in that year. Industrial fuel and power demand for gas is projected to increase through 1995, reaching 7.0 quads by 1995. After 1995, industrial gas consumption is projected to decline in response to strong price competition from coal and technological competition from electricity. Gas consumption for fuel and power falls to 6.5 quads by 2010.

- There are two major components of industrial fuel and power gas consumption: the competition with low-priced residual fuel oil and coal for the boiler market and the diverse fuel competition for process heat applications.

- The most price-sensitive portion of the industrial market is in the generation of steam and power. In 1987, of the 18.2 quads of energy consumed for fuel and power in the industrial sector, roughly 41 percent was consumed to generate steam and power (this includes the 1.8 quads of renewable energy consumed), and gas accounted for about 38 percent of that consumption. This represents about 40 percent of the total industrial gas demand (both fuel and power and feedstock consumption) in 1987.

- To maintain industrial gas volumes, the traditional steam and power market share must be defended with competitive pricing. The best opportunity to increase the gas share is with cogeneration. Cogeneration technologies optimize the assets of gas in steam and power applications and also capture a portion of the direct industrial electrical load. Fuel and power consumption of gas in cogeneration is projected to grow from 0.5 quad in 1987 to 1.2 quads by 2010 or at 3.6 percent per year. Without this growth in gas consumption for cogeneration, gas consumption would fall off much more sharply than projected here.

- Competition between gas and electricity (and in some select applications with coal) will increase in process applications (direct and indirect heat services), and gas technologies will have to keep pace with evolving industrial processes. Currently, gas dominates direct heat services. In 1987 gas was estimated to have captured about 90 percent of all direct heat services. Gas also provides a large share of indirect heat services, approximately 40 percent in 1987.

- Much of the competition for process heat services is really an expected competition for direct heat services between gas and electricity in the future. The high share of natural gas in direct heat applications makes this an obvious target for increasing industrial electricity consumption. Natural gas competes with electricity in metal melting, smelting, metal heating, metal heat treating, drying, and certain types of glass manufacturing. The competition with coal is restricted to calcining and clay firing.

- The 1988 baseline projection does not reflect substantial market loss to either coal or electricity in direct heat applications. Coal gains some market share in calcining and clay firing; however, these are projected to be small markets. The use of electricity in direct heat applications is projected to grow somewhat quicker—from 0.4 quad in 1987 to 0.6 quad by 2010—but gas does not lose significant market share here either.

- Furthermore, it is important to note that, other than cogeneration, the projection presented here does not include any industrial technologies expected to result from GRI's program. Therefore, to the extent GRI is successful in commercializing new industrial technologies, the outlook for industrial gas consumption could be improved.

Coal

- One of the major work efforts undertaken as part of producing the 1988 GRI Baseline Projection was the rebenching of the service demand coefficients (coefficients that relate industrial output to energy input by service) in the industrial sector based on the detailed Energy and Environmental Analysis (EEA) process-oriented ISTUM model. While the 1987 and earlier GRI baseline projections predicted increased industrial coal consumption relative to the base year, the projected rate of growth had been declining in each successive projection. The adoption of the new methodology in the 1988 projection has reversed this trend. The 1988 baseline projection not only predicts that industrial coal consumption will reverse recent trends and increase significantly between 1987 and 2010, but it also includes a higher rate of growth than earlier baseline projections.

- Industrial coal consumption for fuel and power is projected to grow from 1.9 quads in 1987 to 3.4 quads by 2010 or at 2.6 percent per year. This is more than double the projected rate of growth in total industrial fuel and power energy consumption.

- The increase in coal consumption and in the coal share of industrial fuel and power consumption is strictly a function of price. Real gas and residual oil prices are projected to increase at an average annual rate of over 4.0 percent per year between 1987 and 2010. Over the same period, coal prices increase at an average rate of less than 1.5 percent per year. The growing price differential between gas, residual fuel oil, and coal prices, particularly in the later years of the projection, overwhelms many of the difficulties experienced in using coal. Obviously, there are regional price variations, environmental regulations, siting differences, and differences in fuel availability that impact the users' attitude toward each fuel, but the general price trend provides a strong incentive for using additional coal.

- Coal use tends to be restricted to process steam and power generation (cogeneration). Coal consumption for process steam is projected to grow at 3.3 percent per year, or from 1.1 quads in 1987 to 2.4 quads by 2010. Coal consumption for power generation in the industrial sector is largely restricted to very large cogenerators or to particular circumstances where coal is readily available. Between 1987 and 2010, projected coal consumption for cogeneration grows from 0.2 quad to 0.6 quad.

- Coal consumption for other services is limited by the ability to use coal in selected industrial processes. The largest use of coal in other services is for calcining and clay firing. Consumption of coal to provide these services grows slowly, but at the level of detail provided in Table 11, it would appear to remain constant at roughly 0.3 quad through 2010.

Electricity

- From 1960 to 1973 industrial electricity consumption grew at an annual rate of 5.9 percent per year. This growth corresponded to an increase in industrial production of 5.2 percent per year. This relative growth rate suggests that over this period industrial production was becoming more electric-intensive. After the oil price shock in 1973, both industrial production and industrial electricity demand growth slowed down. Between 1973 and 1979, industrial electricity demand grew at 3.5 percent per year and industrial production grew at an annual rate of 2.7 percent. Despite the slower growth rate, the relative rates suggest that industrial production was still becoming more electric-intensive over this period. Between 1979 and 1987, a dramatic change took place in these trends. Growth in industrial production slowed even further, falling to an annual average rate of 2.0 percent over this period. However, in contrast to the earlier periods when electricity demand grew faster than production, over this period, electricity demand did not grow at all. In effect, production was becoming less electric-intensive. A number of factors help to explain this reversal—the increased use of cogeneration (the growth rate reflects only purchased electricity), industrial restructuring, and conservation. The issue is the type of relationship between industrial production growth and electricity demand that can be reasonably expected in the future.

- Purchased industrial electricity consumption is projected to grow from 2.9 quads in 1987 to 4.4 quads by 2010, or at 1.8 percent per year in the 1988 baseline projection. Over the same period, industrial production is projected to increase at 2.7 percent per year. Thus, the baseline projection reflects industrial production growth in line with the level of growth seen between 1973 and 1979, but the increase in electricity demand is one-half of the rate of increase over this period. A number of factors contribute to this lower rate of growth in electricity demand. First, an increasing percentage of the industrial electricity requirements are met by cogeneration, and the cogeneration requirements are reflected as industrial sector consumption of primary fuels (coal, gas, etc.) rather than as electricity consumption. In 1987, cogeneration is projected to meet about 11 percent of industrial electricity needs. By 2010, it meets almost 16 percent of industrial electricity needs. Cogenerated electricity used by the industrial sector grows from 106.2 billion kWh in 1987 to 243.4 billion kWh by 2010. Second, an increasing share of industrial production in the United States is projected to be accounted for by industries that are not energy-intensive. With the exception of the chemicals industry, none of the traditional energy-intensive industries are projected to grow at or above the average rate of growth in industrial production. Third, the 1988 projection reflects continuing strong energy conservation through restructuring and new investment as older equipment is replaced. The majority of new industrial energy-using equipment available today is more efficient than equipment available only a few years ago. These three factors contribute to a slower rate of growth in electricity consumption than historically experienced relative to industrial production growth.

Renewables

- Industrial sector renewable energy consumption includes wood, solar, and hydropower energy consumption. Wood is by far the most important, but solar consumption grows more rapidly (on the basis of percentage) over the projection period. However, solar consumption in the industrial sector is very small, even by the year 2010. Wood is consumed largely in boilers and for cogeneration in the pulp and paper industry (SIC 26). The baseline projection only includes active solar energy systems used for space heating and water heating. The 1988 GRI Baseline Projection does not include an estimate of photovoltaics. The projection of wood renewable energy consumption is based on production growth in the pulp and paper industry. The estimate of hydropower consumption is held constant at 1987 levels of approximately 31 trillion Btu.

- Industrial renewable energy consumption for fuel and power is projected to grow from 1.8 quads in 1987 to 2.9 quads in 2010, or at 2.1 percent per year.

E. Electric Utility Energy Consumption

Table 12. 1988 GRI Baseline Projection of Energy Consumption to Generate Electricity (Quads)

	Actual 1987[a]	1995	2000	2010
Petroleum	1.3	1.8	2.1	2.6
Gas	2.9	3.3	3.8	4.3
Coal	15.2	16.2	17.5	21.7
Nuclear	4.9	6.5	6.7	6.5
Hydro	3.0	3.5	3.5	3.6
Renewables[b]	0.3	0.5	0.7	1.1
Total	27.6	31.8	34.3	39.8
Delivered Electricity[c]	8.4	9.7	10.4	12.0
Canadian Imports[d]	0.2	0.2	0.2	0.1
Purchases from Cogenerators[d]	0.1	0.2	0.2	0.2

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Includes wood, waste, direct geothermal heat etc., used to generate electricity.*
[c] *"Delivered Electricity" refers only to electricity purchased from electric utilities; it does not include cogeneration for self-use.*
[d] *Canadian imports and purchases from cogenerators are included in delivered electricity; both represent sources of electricity other than central station generation.*

1. Energy Demand

Total Demand

- The relationship between electric utility generation and total energy demand is straightforward. As the utility generates more electricity, the electric utilities demand for energy increases proportionately. Between 1960 and 1987, utility generated electricity grew at 4.9 percent per year and total energy input increased at a comparable 4.6 percent per year. The small difference is attributable to shifts in the shares of various fuels used to generate electricity and the different heat rates of the fuels.

- Given this relationship, as long as the requirement for centrally generated electricity increases at a rate faster than the growth in energy delivered to the end-use sectors (residential, commercial, industrial, and transportation), the electric utility sector will consume an increasing portion of total primary energy consumption. In the 1988 GRI Baseline Projection, demand for utility-generated electricity is projected to increase from 2572 billion kWh in 1987 to 3731 billion kWh by 2010, or at 1.6 percent per year. By comparison, total delivered energy to the end-use sectors is projected to increase at only 0.8 percent per year. As a result, electric utilities are projected to consume an increasing portion of total primary energy consumption over the projection period. It increases from 34.8 percent of total primary energy consumption in 1987 to 39.9 percent in 2010, or from 27.6 quads in 1987 to 39.8 quads by 2010.

- However, an increasing portion of total electricity demand by end-users is projected to be provided by non-utility sources (e.g., commercial and industrial cogeneration and Canadian imports). Electricity provided by non-utility sources grows from 195 billion kWh in 1987 to a projected 425 billion kWh by 2010. The vast majority of this non-utility generated electricity is provided through cogeneration. Most of this cogenerated electricity is used onsite, but an increasing portion is sold to utilities for secondary distribution to end-use customers. Including the electricity provided by non-utility sources, total electricity demand by end-users is projected to grow at 1.8 percent per year from 2558 billion kWh in 1987 to a projected 3836 billion kWh by 2010. The increasing percentage of electricity provided by non-utility sources shifts the losses traditionally associated with electricity generation to the end-use sectors or, in the case of Canadian imports, outside of the U.S. energy balance altogether.

- This shift in the location of generation has implications for the energy chosen to generate electricity. A large percentage of non-utility generating sources use natural gas or renewables as an energy source to generate electricity. By contrast, nuclear and coal are the two dominant sources of energy used to generate electricity in central power plants. A reduction in existing non-utility generation or the curtailment of projected growth could result in a large shift in the fuels consumed in the United States. Further, a reduction in non-utility electricity generation would involve a large sectoral shift in energy consumption. If projected non-utility generation in 2010 were instead generated by central power plants, it would add roughly 5 quads to total electric utility energy consumption by the year 2010. This would increase central electric utility capacity requirements in the year 2010 by roughly 100 gigawatts, or by over 10 percent. If only the projected growth in non-utility generation were shifted to the central power plants, it would add almost 3 quads to total electric utility energy consumption by the year 2010 or roughly 7 percent to capacity requirements. This suggests the potential significance of changes in the regulatory environment affecting the electric utility industry.

Petroleum

- Petroleum is used by electric utilities mostly for peaking and intermediate generating purposes. Historically, electric utility consumption of petroleum increased strongly through 1973. Between 1960 and 1973, electric utilities increased consumption of petroleum (mostly residual fuel oil) at an annual average rate of 15.3 percent per year. The oil price spike of 1973 interrupted this growth, but petroleum consumption by electric utilities continued to grow through 1978, reaching 4.0 quads in that year. Starting with the second oil price spike, electric utility petroleum consumption declined sharply. By 1985 petroleum consumption had declined to 1.1 quads.

- With the drop in crude oil prices below $10 per barrel in 1986, electric utility consumption of petroleum again increased sharply, reaching 1.5 quads. With higher petroleum prices and lower gas prices in 1987, petroleum consumption declined somewhat, falling to 1.3 quads. However, petroleum consumption did not fall back to the low 1985 levels. It maintained some of the market gains of 1986. In early 1988 electric utility petroleum consumption has again increased somewhat. Through the first 6 months of 1988 petroleum consumption by electric utilities is up by over 4 percent. Both petroleum and natural gas benefited in early 1988 from the high growth rates in electricity consumption (4.7 percent over the first 6 months) and the drought, which reduced hydro electric output sharply.

- In the near term, through 1995, petroleum consumption by electric utilities in existing generating plants and new peaking turbines is projected to increase sharply, growing from 1.3 quads in 1987 to 1.8 quads by 1995, or at 4.2 percent per year. The primary factor contributing to increased petroleum consumption is more competitive prices. Currently, on a national average basis, natural gas enjoys a competitive edge over petroleum prices. With the end of the gas bubble in the early-1990s, gas prices are projected to increase more rapidly than petroleum prices. Petroleum and gas prices are projected to reach rough parity by the early- to mid-1990s. This will provide petroleum with a better relative competitive position than it has today, particularly in markets such as New England and the Middle Atlantic states where gas prices tend to be somewhat higher than the national averages.

- After 1995 as electric utility capacity becomes increasingly tighter, petroleum plays a larger role in meeting electricity requirements. Petroleum consumption by electric utilities is projected to grow from 1.8 quads in 1995 to 2.6 quads by 2010, or at 2.5 percent per year. By 2010 petroleum meets 6.5 percent of the generating requirement in the electric utility sector. This compares with a 4.7 percent share in 1987.

- The largest share of petroleum consumption for electricity generation remains in the traditional consuming regions of New England, the Middle Atlantic and the South Atlantic. However, strong growth is also projected in the West South Central states and the Pacific 2 states. These five regions account for 90 percent of the projected electricity generated with petroleum by 2010.

Gas

- After recovering in 1987 from the low levels of consumption experienced in 1986 due to the sharp decline in oil prices, electric utility gas consumption should be up only slightly in 1988 in response to the strong growth in electricity consumption and the requirement for increased generation to replace hydro capacity unavailable due to the drought during the summer of 1988. However, the modest growth in 1988 does not provide an indicator of future prospects for electric utility gas consumption. In fact, the modest growth in 1988 should be viewed as more of a surprise. Gas consumption by electric utilities through 1990 or 1991 should remain relatively flat or might even decline slightly as additional, new nuclear and coal-fired facilities come on-line. Between 1987 and 1990, a projected 23 gigawatts of new nuclear or coal capacity is projected to come on-line. The new nuclear units include a number of facilities which originally had earlier on-line dates, but which were delayed by construction problems.

- However, after the early-1990s with generation requirements for centrally generated electricity growing at greater than 2 percent per year and no additional new capacity coming on-line, gas demand by electric utilities will grow. The 1988 baseline projection shows gas consumption by electric utilities growing from 2.9 quads in 1987 to 3.3 quads by 1995. After 1995, with a continued tightening of electric utility generating capacity, gas consumption by electric utilities continues to grow, reaching 4.3 quads by 2010. This compares with historical peak consumption of gas by electric utilities of 4.1 quads in 1971. However, in 1971 the 4.1 quads accounted for 24 percent of total electricity generation. The 4.3 quads of gas consumption in 2010 represents only 11 percent of total electricity generation by central power plants.

- Gas consumption shown in Table 12 only includes natural gas purchased and consumed directly by electric utilities. It does not include any gas consumed in cogeneration in the industrial or commercial sectors. Gas consumed for cogeneration is included as energy delivered and consumed in those sectors. However, electricity purchased from cogenerators by electric utilities and sold to utility customers is shown and included as part of delivered electricity in Table 12. Cogenerated electricity purchased by electric utilities is projected to grow from 38.6 billion kWh in 1987 to 70.6 billion kWh by 2010.

- The baseline projection includes 48.1 gigawatts of new gas-fired generating capacity between 1987 and 2010. Of this, 3.7 gigawatts are currently included in electric utility plans. The majority of this new capacity, approximately 30 gigawatts, is gas-fired combined-cycle capacity. However, the 1988 baseline projection also includes repowering of older capacity as an option for the first time. The projection estimates that 57.5 gigawatts of gas-fired capacity will be repowered between 1987 and 2010. To the extent that higher energy prices make repowering a less viable option, these repowered facilities would be replaced with new capacity, much of which would be combined-cycle facilities.

Coal

- Through the early-1990s the electric utility generating capacity included in the projection, both existing and added, is based on published utility plans. GRI has, in some limited circumstances, adjusted the published figures where it appears unlikely that the capacity will actually be available according to currently published plans.

- After the early-1990s, coal use is based upon an economic determination limited to account for the constraints upon coal use arising from existing environmental policies and infrastructure limitations. The 1988 baseline projection does not include any potential economic impact from possible acid rain legislation.

- Historically, growth in electric utility coal consumption parallels growth in electricity demand. Between 1960 and 1987, electricity demand grew at 4.9 percent per year. Over the same period, coal consumption also grew at 4.9 percent per year. The 1988 GRI Baseline Projection reflects a similar pattern, with utility generated electricity projected to grow by 1.6 percent per year between 1987 and 2010. Over the same period, coal consumption is projected to grow from 15.2 quads to 21.7 quads or at 1.6 percent per year.

- However, near-term coal consumption follows a pattern similar to that for natural gas. While coal-fired nameplate generating capacity increases from 316 gigawatts in 1987 to 323 gigawatts by 1990, coal consumption remains relatively constant at roughly 15 quads. Coal consumption is held down by the nuclear bubble. Many of the new nuclear plants that come on-line between 1987 and 1990 compete directly with coal-fired power plants for baseload generation. As a result, over this period coal capacity utilization falls from 52 percent in 1987 to 50 percent by 1990. After 1990 coal capacity utilization increases to over 56 percent by 2010 as available generating capacity becomes tighter. Coal generating capacity is projected to grow to 422 gigawatts by 2010.

Nuclear

- The 1988 projection includes only ongoing construction by utilities. No new orders for nuclear plants are included in the projection, and some plants currently considered to be "on order" are assumed to be deferred or cancelled. Between 1987 and 1995, the last year a new nuclear facility is scheduled to come on-line, 11 nuclear plants will be completed, providing a total of of 11.9 gigawatts of new capacity at a total estimated real cost of $32 billion (1987$). The estimated 1987 and 1995 capacity (gigawatts) by region and the number of plants (shown in parentheses) are as follows:

	1987	1995
New England	5437 (8)	5437 (8)
Middle Atlantic	15460 (17)	16560 (18)
South Atlantic	23050 (26)	24210 (27)
East North Central	18407 (22)	20620 (24)
West North Central	5669 (8)	5669 (8)
East South Central	8399 (8)	11048 (11)
West South Central	3800 (4)	7272 (7)
Mountain 1	0 (0)	0 (0)
Mountain 2	2540 (2)	3810 (3)
Pacific 1	2230 (2)	2230 (2)
Pacific 2	5744 (6)	5744 (6)
United States	90736(103)	102600(114)

- A number of active nuclear plants are either currently or have been out of operation during 1987 or 1988 for extended repair or evaluation. Most noticeable in this group are the Pilgrim facility in New England, the Peach Bottom 2 and 3 units in the Middle Atlantic, the numerous TVA facilities, and the Rancho Seco plant in the Pacific 2 region. The baseline projection specifically accounts for these units being unavailable. In most cases, the projection assumes the units will be available again within 2 or 3 years.

- Between the peak in nuclear capacity in 1995 and 2010, 13 nuclear facilities reach their originally scheduled retirement dates. The 1988 baseline projection assumes that these plants will be retired. As a result, nuclear capacity declines to 97.0 gigawatts by the year 2010. If the life of these nuclear facilities is extended, which is questionable because of the probable difficulties of relicensing older facilities under current standards, some coal capacity additions projected here would be deferred.

Renewables

- Electric utility renewable energy consumption includes generation of electricity with independent power producer (IPP) hydro, geothermal, wood, refuse, and other renewable sources (mostly wind farms, but also some solar). Where possible, the projection of renewable energy consumption is based on stated plans discounted for doubtful programs. For example, geothermal generation is largely based on plans for the Geyser, California, facilities. The renewable energy projections are largely based on data from *Power Plays* and *Generating Energy Alternatives*, publications available from the Investor Responsibility Research Center, and on data from the DOE/EIA *Inventory of Power Plants*.

- Electric utility renewable energy consumption is projected to grow at a rate of over 6 percent per year over the projection time frame, from 0.3 quad in 1987 to 1.1 quad by 2010. The Pacific 2 region (California) dominates growth in the use of renewables. The Pacific 2 regions accounts for almost 70 percent of renewable consumption in 1987. Even by the year 2010, the Pacific 2 region still accounts for slightly over 40 percent of all renewable energy consumption in the electric utility sector.

- In 1987 an estimated 5450 megawatts of renewable energy generating capacity was available. It is projected that by 2010, renewable capacity will grow to roughly 21,500 megawatts. The projection assumes that renewable energy consumption is negatively impacted by the current low energy prices and the elimination of many of the tax incentives which spurred growth in renewables. The elimination of tax incentives is assumed to strongly constrain growth in IPP hydro, wind, and solar renewable energy consumption, in particular. However, the projection assumes that by the mid-1990s, as energy prices again begin to increase more rapidly and as electric utility capacity becomes tighter, that electric utility consumption of renewable energy will accelerate.

- The fastest growing renewable energy category is refuse-derived power generation. Refuse capacity is projected to grow from an estimated 590 megawatts in 1987 to over 8000 megawatts by 2010. Other renewable consumption (mostly solar and wind generation) is projected to decline in the near term, through the late-1990s. Other consumption grows after 2000, but only reaches the levels attained in the mid-1980s by 2010. No new wood-fired power generation is included in the projection. In fact, the existing wood-fired plants are assumed to be gradually retired. Geothermal capacity is projected to grow gradually over time, reaching 4500 megawatts by 2010. This compares with capacity today of roughly 2500 megawatts. After growing slowly through the mid-1990s, in response to low energy prices and the elimination of many tax incentives, growth in IPP hydro is assumed to accelerate, reaching 7500 megawatts by 2010 compared with an estimated 1100 megawatts today.

2. Generating Capacity

- The 1988 projection continues to show a need for utilities to initiate construction of new capacity additions beginning in the 1990s. Table 13 presents the projected required capacity and the existing planned capacity expected to be on-line in future years, based on published utility plans minus expected retirements. The data illustrates that in the early years of the projection, in the aggregate, utilities expect to have sufficient capacity. The aggregate U.S. data, however, says nothing about the adequacy of regional or subregional generating capacity. Regional shortfalls could occur much sooner than shown in Table 13.

Table 13. Expected Electric Utility Generating Capacity, Required Capacity, and Capacity Shortfalls (Gigawatts)

	Expected Capacity[a]	Required Capacity[b]	Shortfall Or (Surplus)
1987	707.8	637.5	(70.3)
1988	716.1	654.7	(61.4)
1989	720.9	667.7	(53.2)
1990	724.5	681.0	(43.5)
1995	740.3	734.1	(6.2)
2000	719.7	788.9	69.2
2005	697.4	848.6	151.2
2010	667.9	906.7	238.8

[a] *Existing capacity plus currently planned capacity less retirements and capacity repowered. The projection assumes repowering of some capacity; without repowering, the capacity would be retired.*
[b] *Required capacity is calculated based on an assumed reserve margin of 20 percent over peak load.*

- By the year 2000, less than 15 years from today, the projection shows a requirement for almost 790 gigawatts of capacity. Identifiable planned capacity accounts for only about 720 gigawatts, and completion of some of the planned units is doubtful. By the year 2010, well over 200 gigawatts of new capacity above that included in current utility plans will be required. This new capacity will be necessary despite assumptions of a substantial reduction in the reserve margin from today.

- Table 14 presents the capacity data shown in Table 13 by the baseline projection regions. The exhibit shows the potential for capacity problems in the New England and South Atlantic regions and potential problems in a number of other regions by 1995, including the Middle Atlantic, West North Central, and West South Central regions. The data in Table 14 presents total capacity in each region. It does not consider net regional interchange, electricity imports, or capacity unavailable due to repair or accidents. In regions where the expected capacity is close to the required capacity, such issues are particularly important in determining the eventual balance of electricity demand and supply. Again, even the regional data in Table 14 does not demonstrate the adequacy or inadequacy of subregional generating capacity (e.g., Long Island in the Middle Atlantic region). Capacity problems at the subregional level could occur sooner than suggested by Table 14.

Table 14. Expected[a] Electric Utility Generating Capacity, Required[b] Capacity, and Capacity Shortfalls by Region (Megawatts)

	1987		1995		2010	
	Expected	Required	Expected	Required	Expected	Required
New England	22,362	23,183	22,654	25,728	21,287	27,626
Middle Atlantic	82,462	72,083	84,636	80,592	69,886	90,929
South Atlantic	132,533	131,454	138,357	156,759	132,800	201,025
East North Central	120,463	100,310	124,879	110,798	102,084	133,001
West North Central	57,041	49,640	57,734	54,314	50,766	61,344
East South Central	60,996	52,498	66,741	60,014	55,726	74,708
West South Central	99,755	93,094	106,956	104,631	101,592	135,251
Mountain 1	31,198	22,379	34,280	27,579	33,623	37,355
Mountain 2	18,901	13,277	21,526	18,054	20,540	28,439
Pacific 1	33,963	25,647	33,356	31,008	33,156	38,379
Pacific 2	48,102	53,976	49,208	64,643	46,410	78,674

[a] *Existing capacity plus currently planned capacity less retirements and capacity repowered. The projection assumes repowering of some capacity; without repowering, the capacity would be retired.*
[b] *Required capacity is calculated based on an assumed reserve margin of 20 percent over peak load.*

- In the discussion of the residential and commercial sectors it was pointed out that the growth rate of electricity generation required from central power plants of 1.6 percent per year in the 1988 baseline projection could be conservative. In fact, while many projections are showing relatively low rates of growth in electricity requirements, recent historical data suggests much higher growth rates. For example, over the period from 1960 to 1987 electricity demand grew at an annual rate of over 4.8 percent per year. Further, while demand growth slowed over the period from 1980 to 1987, it still averaged over 2.3 percent per year. Over the last 3 years, the trend has actually been toward higher rates of growth (after a slow rate of growth in 1986 of 1.1 percent, demand grew by 4.5 percent in 1987, and over the first 6 months of 1988 by over 4.7 percent). If this trend continues, it will compound the problem electric utilities will have in meeting generation requirements.

- As an example, if electricity required from central power plants averaged growth of 2.1 percent between 1987 and 2010, only 0.5 percent higher than that projected in the baseline projection, this would add an additional capacity requirement on electric utilities of over 100 gigawatts by 2010. This corresponds to almost a 12 percent increase in required electric utility generating capacity, the equivalent of all of the capacity built during the period from 1980 to 1987. This is required new capacity in addition to the projected shortfall between current utility plans and required capacity, which the baseline assumes will be met by an as yet unspecified utility construction program. Obviously, small mistakes in the projected growth of future electricity demand could have very large impacts on the need for future generating capacity.

- One aspect of the situation that is not apparent from the aggregate data is that much of the new capacity currently being added is intended for baseload service and is not suitable for peaking or, in many cases, even for intermediate service. Traditionally, coal, nuclear, and hydro capacity are used in baseload service, and oil and gas (with the exception of the West South Central region) are used in intermediate and peak load service. With the excess amount of baseload capacity being added to capacity today (most new capacity today is either large coal-fired or nuclear units), older electric utility capacity that was intended for baseload service is being used in a cycling mode, which is an inefficient and expensive use of this type of capacity. This suggests that much of the new capacity required by electric utilities in the future will be targeted to intermediate and peak capacity requirements. However, the use of traditional baseload capacity in a cycling mode also misrepresents the capacity available for baseload electric generation in the future. The sustainable capacity available from a generating facility is calculated relative to its peak generating load over the facility's normal operating cycle. However, the sustainable capacity of a baseload plant being used in a cycling mode is determined based on its peak use in the cycling mode. Few plants, if used in baseload capacity, could sustain peak generating levels over a baseload cycle. Thus, a baseload plant used in a cycling fashion provides an overestimate of the reserve margin. This, again, suggests that the capacity problem may be larger than suggested by the current aggregate data.

- The projected growth in electricity demand, particularly with the emphasis on requirements for additional peak and intermediate capacity, will provide an opportunity for increased use of natural gas by electric utilities. As the demand for electricity outstrips the capacity of existing electric generating facilities, gas will offer a competitive edge for new peaking facilities using combined-cycle technology. Combined-cycle facilities have relatively low capital costs and a short construction lead time.

3. *Electricity Prices*

- Electricity prices are developed in the analysis by allocating the electricity production costs, including the costs of required expansion, plant life extension, and cancelled generating capacity, over the electricity-consuming sectors in accordance with conventional ratemaking practices.

- The projection does not currently consider the impact of potential acid rain legislation or nuclear waste disposal on electricity prices. To the extent that acid rain legislation or nuclear waste disposal could force the substitution of more expensive energy sources for coal or increase environmental costs, electricity prices could be higher.

- Further, in view of the uncertainty about the utility systems' ability to meet the requirement for increased generating capacity, it is possible that effective electricity prices could be somewhat higher than those shown in the baseline projection, either due to ratemaking policies designed to discourage peak demand or due to costly expedients to achieve generation requirements, such as the reactivation of old, inefficient facilities. Under this circumstance, gas technologies that serve cogeneration or utility peak loads would be placed in an even more advantageous competitive environment.

- The changing ratio of electric prices to gas prices in the consuming sectors is projected as follows:

	1987	1995	2000	2010
Residential	4.1	3.5	3.1	2.7
Commercial	4.6	3.8	3.2	2.5
Industrial	5.4	3.6	3.1	2.4

- In addition to the variation in the ratios between end-use sectors, there is significant regional variation in the ratios. For example, in the residential sector in 2010, the ratio of electricity prices to gas prices ranges from 3.5 in the Pacific 2 region to 2.2 in the Pacific 1 region. In the commercial sector, the range is from 3.5 to 1.6, and in the industrial sector the ratio ranges from 3.8 to 1.1.

- The relatively high ratios of electric-to-gas prices in 1987 helps to explain the recent preference in many regions for gas over electric equipment. For example, since 1983 the gas share of space heating in new single-family homes has surged from 40 to 52 percent today. The "typical" new electric heat pump sold today has a space-heating efficiency of around 2.5. Typical is defined here as the average system sold, not the state-of-the-art system. By comparison, the "typical" new gas-fired furnace sold today has a space-heating efficiency of 0.85. For the electric system to be competitive with the gas system, the ratio of electric-to-gas prices must be less than 3:1. With a ratio in 1987 of 4:1, gas is the less expensive system. The relative competitiveness of gas and electricity would, of course, vary by region, by the relative capital costs of the systems, and by the precise efficiency of the systems being compared. However, the aggregate ratios are reflective of current market trends.

- However, while the ratios suggest that gas is the clear choice today, the electric-to-gas price ratios are projected to steadily decline between 1987 and 2010 in the residential, commercial, and industrial sectors. The declining ratios reflect an increase in gas prices as the gas bubble ends and little real increase in electric prices, at least through the year 2000, as the current utility construction program draws to a close. With a decline in the ratios, the competitive position of electricity is projected to steadily improve. This suggests the need to continue to improve gas-fired equipment to remain competitive with electric equipment over the time frame of the projection.

F. Transportation Sector Energy Consumption

Table 15. 1988 GRI Baseline Projection of Delivered Energy Consumption—Transportation Sector (Quads)

	Actual 1987[a]	1995	2000	2010
Petroleum	20.7	22.1	23.6	24.3
Gas[b]	0.5	0.6	0.7	0.8
Total	21.2	22.7	24.3	25.1

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Includes 0.2 quad of demand by methane vehicles in 2010. The estimate of gas consumed in methane vehicles reflects the estimate of the A.G.A. Gas Demand Committee.*

Total Demand

- From 1960 through 1973, transportation sector energy consumption increased steadily in the United States from 10.6 quads in 1960 to 18.6 quads in 1973. In fact, the rate of growth actually accelerated in the second half of the 1960s as the economic prosperity of the time led to the purchase of more and bigger vehicles, which resulted in a decline in the average efficiency of automobiles. As a result of the oil price spike in 1973, transportation sector energy consumption fell sharply in 1974. Furthermore, vehicle efficiency began to improve after 1973. Between 1973 and 1987, the average efficiency of a passenger car improved at 3.5 percent per year. However, the decline in energy consumption in 1974 proved to be short-lived. Transportation energy consumption began to grow again in 1975 and continued to grow through 1978, reaching 20.5 quads. With the second oil price spike in 1979, transportation energy consumption started a decline that lasted through 1982. As a result of that decline, consumption in 1987 was roughly at the same level as in 1978.

- Transportation sector energy consumption is, of course, dominated by petroleum consumption. In 1987 petroleum consumption accounted for 97 percent of the energy consumed in the transportation sector. The remainder was largely gas used in pipeline compressor stations.

- Total transportation sector energy consumption is projected to grow from 21.2 quads in 1987 to 25.1 quads by 2010, or at 0.7 percent per year. However, the rate of growth in energy consumption varies considerably over the projection time frame. The rate of energy consumption growth changes in response to variations in the rate of growth of the vehicle stock, vehicle efficiency improvement, and in the mix of vehicles purchased (cars, light trucks, heavy trucks, etc.). For example, during the period from 1987 to 1995, transportation energy consumption grows at 0.9 percent per year. Between 1995 and 2000, energy consumption growth accelerates to 1.4 percent. Finally, between 2000 and 2010, consumption growth slows to only 0.3 percent per year.

- The 1988 projection does not assume the enforcement of the Corporate Average Fuel Economy (CAFE) standards by the National Highway Traffic Safety Administration. The projection assumes that, with more moderate growth in petroleum prices, auto manufacturers are not able to meet the CAFE standards as consumers purchase bigger, less efficient vehicles.

Petroleum

- The dominant petroleum products used in the transportation sector are gasoline and distillate fuel oil, which together account for 82 percent of total transportation sector petroleum consumption in 1987.

- Petroleum consumption is projected to grow at 0.9 percent per year between 1987 and 1995 (from 20.7 quads to 22.1 quads) despite a projected slow growth in the size of the stock of passenger cars of only 0.2 percent per year. The 0.9 percent per year growth in petroleum consumption is supported by a somewhat stronger 0.8 percent per year growth in the size of the truck fleet and, more importantly, a projected decline in the passenger car stock average efficiency as people purchase bigger cars in response to lower gasoline prices. This is reflected in a growth in the share of domestically manufactured cars, which tend to have a lower efficiency ratings. (In 1987 the domestic in-use new fleet average MPG was 21.8; the imported fleet average MPG was 24.3.) The share of new passenger cars that are manufactured domestically is projected to grow from 69 percent in 1987 to 74 percent by 1995.

- In the period from 1995 to 2000, petroleum consumption is projected to increase from 22.1 quads to 23.6 quads, or at a relatively more rapid 1.4 percent per year, as the size of the passenger car stock grows at a much more rapid 1.2 percent per year. Further, while the new passenger car MPG reverses and begins to improve when gasoline prices begin to increase, the improvement in the MPG of all vehicles is moderated as a large share of new vehicle sales is accounted for by trucks. The truck share of vehicles sales is projected to grow from 32 percent in 1995 to over 35 percent by 2000.

- After 2000, growth in transportation sector petroleum consumption slows to 0.3 percent per year as higher petroleum prices spur more rapid improvement in vehicle efficiency. Between 2000 and 2010, new passenger car efficiency is projected to improve from 24.7 to 30.1 MPG. Petroleum consumption reaches 24.3 quads by 2010.

Gas

- Gas demand in the transportation sector is primarily associated with pipeline compressor use. It also includes some demand for gas by methane vehicles for fleet use. Methane vehicle consumption of gas is projected to grow from 4 trillion Btu in 1987 to 154 trillion Btu in 2010. The methane vehicle consumption estimate is based on the A.G.A. Gas Demand Committee estimate.

V. Gas Supply and Price

For purposes of planning GRI's R&D program, two of the most critical components of an energy and economic projection are the gas supply quantities and associated prices. The projection indicates that adequate gas supplies can be obtained to meet the projected U.S. gas demand levels. The gas industry, however, cannot rely solely on existing supply sources and current practices. New supply initiatives will be necessary to meet projected demand.

The lower-48 gas production in the 1988 GRI Baseline Projection is explicitly divided into production expected to occur from base technologies and incremental production arising from advanced technology. Base technologies are a continuation of current practices. Advanced technologies are expected to be available as a result of new initiatives on the part of the gas industry, such as the GRI Natural Gas Supply R&D program.

The base technology lower-48 natural gas supply and price trends used in the 1988 GRI Baseline Projection are developed using the GRI Hydrocarbon Model*. In addition, the GRI Hydrocarbon Model used in the 1988 GRI Baseline Projection has been modified to explicitly calculate the effects of advanced technology on gas production from Devonian shale and coal seams in the Black Warrior Basin in Alabama. The scope of the GRI Hydrocarbon Model resource base will be expanded in the future to include the effects of technology on gas production from other gas sources as well (e.g., coalbed methane, tight sands).

The quantities and prices of gas imports, gas from Alaska, and supplemental sources of gas are derived exogenously to the GRI Hydrocarbon Model. They do not involve rigorous economic selection on a competitive marginal cost basis for the introduction of such supplements, but, rather, are based on existing agreements and practices, known proposals, and judgmental extensions of the current situation. Should these quantities prove to be less than projected, the deficit would be made up by increased lower-48 production at higher marginal prices.

Beginning with the 1987 baseline projection, GRI has explicitly analyzed the patterns of natural gas transportation. The analysis indicates that transportation patterns will shift significantly in the future. Lower-48 production gradually shifts away from the West South Central states (Louisiana, Texas, Oklahoma, and Arkansas). The regional shift in gas supply is accompanied by a shift in gas demand patterns. Gas sources, such as Devonian shale in the East, coastal LNG deliveries, and incremental gas resources arising from advanced technology in the historical producing areas of the West South Central region, will be enhanced in value as longer hauls and new pipeline capacity are required to deliver an increasing portion of supplies from the other producing regions.

The shift in regional gas transmission patterns will ultimately entail some significant investments on the part of the gas industry. The pipeline component of the GRI Hydrocarbon Model was modified to introduce the effects of this new investment on gas transmission charges in the 1988 GRI Baseline Projection.

The following discussion details the projection of gas supplies and prices, the transportation and distribution costs, and projected transportation patterns.

A. Gas Supply and Prices

Tables 16 and 17 summarize the quantities and the acquisition prices for the gas supply sources that are associated with the 1988 GRI Baseline Projection.

Lower-48 Production

- As a result of advanced technology, lower-48 gas production at prices competitive with alternative fuels remains essentially constant through the year 2000 and declines about 13 percent between 2000 and 2010. The average prices for base technology lower-48 production were developed assuming the NGPA continues to control the price of certain "old gas" sources as provided by current law.

* More detailed description is contained in *The Long-Term Trends in U.S. Gas Supply and Prices: The 1988 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, available from GRI.

- The prices for the incremental lower-48 gas production arising from advanced technologies are set equal to the average price of flowing decontrolled lower-48 gas production in the GRI Hydrocarbon Model, although analyses indicate that resource costs for this production might be substantially lower.

Table 16. 1988 GRI Baseline Projection of Gas Supply Trends (Quads)

	Actual 1987[a]	1995	2000	2010
Lower-48 Production[b]	15.7	15.7	15.8	14.4
Base Technology[c]	(15.7)	(14.4)	(13.5)	(9.9)
Advanced Technology	(—)	(1.3)	(2.3)	(4.5)
Alaskan Production	0.2	0.2	0.2	1.4
Southern[d]	(0.2)	(0.2)	(0.2)	(0.2)
Northern[e]	(—)	(—)	(—)	(1.2)
Pipeline Imports	1.0	1.6	1.6	1.8
LNG Imports	0.0	0.2	0.4	0.8
Coal Gas	0.1	0.1	0.1	0.2
Other Gas[f]	0.1	0.2	0.2	0.2
Total Purchases	17.1	18.0	18.3	18.8
Lease and Plant Fuel	1.0	1.0	1.0	1.0
Total Supply	18.1	19.0	19.3	19.8
Losses & Exports	0.4	0.4	0.4	0.4
Total Demand	17.7	18.6	18.9	19.4

[a] *Taken from the March 1988 DOE/EIA Natural Gas Monthly published June 1988.*
[b] *Lower-48 production does not include lease and plant fuel supplies.*
[c] *Includes 0.1 quad of production from Devonian shale in each year. Balance of Devonian shale production included under Advanced Technology.*
[d] *Southern Alaska natural gas supplies were estimated from projected Alaskan consumption.*
[e] *Northern Alaska natural gas represents supplies delivered to the lower-48 via ANGTS.*
[f] *Other gas includes SNG from petroleum, propane-air, and refinery gas.*

Table 17. 1988 GRI Baseline Projection of Gas Acquisition Price Trends (1987$/MMBtu)

	Actual 1987[a]	1995	2000	2010
Lower-48 Production	1.67	2.86	3.54	6.05
Base Technology[b]	(1.67)	(2.85)	(3.52)	(6.01)
Advanced Technology	(N/A)	(3.01)	(3.66)	(6.13)
Northern Alaska	—	—	—	6.16
Pipeline Imports	2.14	3.20	3.86	6.37
LNG		3.20	4.10	6.81
Coal Gas	3.84	3.84	3.84	6.16
Other Gas[c]	3.21	4.17	4.98	7.58
Average	1.71	2.91	3.60	6.14

[a] *Taken from the March 1988 DOE/EIA Natural Gas Monthly published June 1988.*
[b] *Price for natural gas supplies consumed in Alaska, lower-48 conventional, and unconventional natural gas supplies using base technology.*
[c] *Other gas includes SNG from petroleum, propane-air, and refinery gas.*

- The growth in lower-48 wellhead prices is quite steep, particularly through 1995. Despite this steep growth, real lower-48 wellhead prices do not return to their 1983 peak until after 1995.

- The near-term growth in wellhead prices reflects the combined effects of four factors: the return of gas prices to replacement cost levels as the "gas bubble" ends; the substantial reduction in the portion of aggregate supply derived from low-priced gas volumes that remain subject to price controls; the effects of resource depletion; and the recovery of factor costs (i.e., drilling costs, industry rate of return) as a result of external market factors such as higher oil prices and increased drilling activity. The last two factors remain significant after 1995. Throughout the entire projection period, resource depletion accounts for about two-thirds of the growth in wellhead prices, and the other factors account for the remainder.

Alaska Natural Gas Via ANGTS

- The Alaska natural gas transportation system (ANGTS) is assumed to begin operation in 2007 at a throughput of 0.7 quad per year. In 2010, its throughput is expanded to 1.2 quads per year.

- The fixed price component of ANGTS deliveries is based upon the cost estimates of the pipeline consortium in 1982. Because of competitive pressures, the wellhead price for ANGTS gas is held fixed at $1.00 per MMBtu (1987$) until the total price of ANGTS gas delivered to the lower-48 equals the Canadian border price. Thereafter, the wellhead price of ANGTS gas increases as the ANGTS price tracks the Canadian border price.

- Recently, the principal sponsors of ANGTS have reevaluated the capital costs. This analysis has reduced the capital costs for ANGTS by almost 45 percent. This would mean that ANGTS gas could be competitive with lower-48 wellhead prices in the 1988 GRI Baseline Projection when it is introduced in 2007.

Pipeline Imports

- Real prices for pipeline imports at the border are set on a competitive basis with lower-48 wellhead prices. Prices vary, however, depending upon the point of competition. If the border export point is a producing region in Canada, then the import price is determined by the marginal wellhead gas price. If the export point is a consuming region, then the import price is determined by the regional citygate price, adjusted for the cost to bring the gas from the border point to the nominal Canadian regional citygate location.

- Pipeline imports grow substantially through 1995, and show little growth thereafter. Canadian imports remain essentially constant after 1995 as a result of the initiation of gas deliveries from Canadian frontier regions (e.g., MacKenzie Delta, Atlantic) in the late-1990s. Pipeline imports grow modestly after 2000 due to the resumption of Mexican gas exports to the United States.

- Canadian frontier supplies will require new capital investments, such as the Polar Project to bring gas from Canadian Arctic resources or the infrastructure to develop and transport gas from new offshore regions. Renewed imports from Mexico will require new policy decisions by Mexico and probably significant investment in infrastructure as well.

- The levels of pipeline imports in the 1988 GRI Baseline Projection are not constrained by technical resource considerations in either Canada or Mexico. The export policies of both countries, of course, represent an uncertainty. The projection assumes that exports will be viewed as attractive by both countries in the amounts shown.

- The gas wellhead prices in Canada implied by the imported Canadian gas prices in the 1988 GRI Baseline Projection are consistent with lower-48 wellhead prices.

LNG Imports

- The baseline projection assumes that LNG imports are resumed in the late-1980s through the existing terminals at Lake Charles, Louisiana, and Everett, Massachusetts. The LNG imports into the South Atlantic demand region using existing terminals are assumed to resume in the late-1990s.

- The LNG import price is set equal to the citygate price of the region into which it is imported if that region is a consuming region, such as the South Atlantic. However, LNG imports into Lake Charles, Louisiana, are set equal to the wellhead price of flowing decontrolled gas because Louisiana is a net exporter of gas to other states.

- The LNG prices in the 1988 GRI Baseline Projection provide adequate economic incentives to resume LNG imports.

Coal Gasification

- Only the existing Great Plains coal gasification plant is included through the year 2000. The projection assumes that the plant will continue to be operated. The price projection would cover the plant's operating costs and some capital costs until the mid-1990s, after which it would become profitable considering the capital cost writeoff that has already occurred.

- The price of gas from the plant is assumed to equal the estimated plant operating costs until the marginal lower-48 cost exceeds the operating cost. At that point, the price of coal gas tracks the average price of flowing decontrolled lower-48 gas production.

- Two half-sized gasification plants are assumed to be added after the year 2000 using advanced technology. The economics of these other facilities have been analyzed to determine their viability at the gas prices and supply circumstances indicated by the GRI Hydrocarbon Model during this period.

B. Transportation and Distribution Costs

The GRI Hydrocarbon Model simulates the flow of lower-48 gas supplies from their point of acquisition through a simplified U.S. gas transportation network to the burner tip using the Flowing Gas Pipeline component of the GRI Hydrocarbon Model. Through the 1986 projection, the charges to transport gas were calculated on a cost-of-service basis, reflecting an assumption that the overwhelming portion of gas would continue to be transported under the traditional merchant function. It was also assumed that the net gas transportation plant in service remained constant. Thus, changes in the real gas transportation charges per MMBtu only reflected changes in volume throughput and gas prices for pipeline fuel.

Since the mid-1980s, gas has faced intense price competition in the fuel-switchable markets. This competition, together with regulatory policy initiatives that encourage gas-to-gas competition, has eroded the traditional merchant role of the gas transportation industry in which the pipeline companies purchased most of the gas for resale to end-users or to distribution companies. Only a very small volume of gas was purchased directly by users or distribution companies (LDCs) who then contracted for gas transportation services. In 1982, only about 3 percent of all gas in the interstate market was transported under carriage arrangements. In the first half of 1988, it has been estimated that almost 60 percent of interstate gas movements have been by carriage.

Accordingly, the calculations of gas transportation charges were modified in the 1987 GRI Baseline Projection to take into account the growing role of contract transportation. Projected gas transportation charges are now also modified by competitive pressures from residual fuel oil competition at the burner tip.

The pipeline component of the GRI Hydrocarbon Model was modified in the 1988 baseline projection to reflect changes in the transmission rate base and the long-term changes in gas transmission patterns. GRI analysis of the long-term trends in gas transportation costs indicate that real gas transmission costs are likely to decline over the next decade as a result of increased gas sales, lower capital costs, continued competitive pressures in the gas industry, and the amortization of the existing rate base.* These factors will enhance the gas transmission industry's ability to undertake new investments to deal with the changing patterns of gas transmission in the lower-48 states without a substantial increase in gas transmission charges. The costs of local distribution are likely to remain stable or decline for many of the same reasons.

Table 18 shows the long-term trends in gas transportation charges in the 1988 GRI Baseline Projection. The table shows a decline in gas transmission charges through the year 2000. The growth after the year 2000 reflects the substantial levels of new investments as the gas transmission patterns accelerate their change. Distribution charges, on the other hand, continue to decline, representing a shift in gas sales to the industrial and electric utility sectors and the effects of higher sales. The decline in distribution charges after 2000 offsets most of the increase in transmission charges.

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* Energy and Environmental Analysis, Inc., *Factors Affecting Growth in Gas Transportation Costs Since 1970,* GRI Topical Report, November 1987.

Table 18. Gas Transportation Charges in the 1988 GRI Baseline Projection (1987$/MMBtu)

	Transmission	Distribution	Total
1987	0.76	1.22	1.98
1995	0.73	1.14	1.87
2000	0.74	1.10	1.84
2010	0.84	1.03	1.87

Analysis of industrial gas sales in 1987 indicates that about 60 percent of industrial gas sales were through nontraditional ratemaking, reflecting the effects of gas-to-gas competition and the effects of competition from low-priced residual fuel oil. Because the gas-to-gas competition is expected to be largely gone by the mid-1990s, the competitive share of industrial sales declines to about 45 percent by 1995 and remains relatively unchanged thereafter. Table 19 presents the projected trends in industrial burnertip gas prices that result from the dual pricing methodology.

Table 19. Burnertip Industrial Gas Prices in the 1988 GRI Baseline Projection (1987$/MMBtu)

	Cost of Service	Interfuel Competitive	Weighted Average
1987	3.76	2.13	2.77
1995	4.65	3.53	4.04
2000	5.39	4.13	4.71
2010	8.09	6.62	7.31

Interfuel competition is much more severe in the electric utility sector. Analysis indicates that about 90 percent of sales to electric utilities were under some form of carriage arrangement in 1987. Table 20 presents the projected trends in electric utility prices that result from the dual pricing methodology. Table 20 shows that almost all gas sales to electric utilities move under competitive carriage arrangements in the future.

The competitive carriage tariffs do not provide full cost recovery using conventional accounting, resulting in reduced revenues to transmission companies and LDCs. Although the gas industry accepts reduced revenues to maintain the fuel-switchable market, with a resultant lower ROR, sensitivity analyses indicate that the loss of the fuel-switchable market would lead to a much larger decrease in revenues unless substantial increases in gas transportation charges to the remaining gas customers were allowed.

Table 20. Burnertip Electric Utility Gas Prices in the 1988 GRI Baseline Projection (1987$/MMBtu)

	Cost of Service	Interfuel Competitive	Weighted Average
1987	3.35	2.14	2.26
1995	3.85	3.66	3.67
2000	4.61	4.23	4.25
2010	7.34	6.66	6.69

C. Transportation Patterns

The U.S. gas distribution system was developed under circumstances where the major share of U.S. gas supply came from the West South Central region (Louisiana, Texas, Oklahoma, and Arkansas). The gas in this region was transported to virtually every consuming region in the United States. As a result, the U.S. gas transmission system predominantly originates in the West South Central region.

The projection of lower-48 gas production in the 1988 GRI Baseline Projection indicates that lower-48 production will play a declining role in overall U.S. gas supply. In 1987, about 93 percent of lower-48 gas consumption was supplied by lower-48 production. By 2000, that share is projected to fall to about 87 percent, and by 2010, to about 78 percent.

The effect of this declining share of lower-48 production on gas transmission patterns is exacerbated by the shift of lower-48 production away from the West South Central region. Further, with the exception of Mexican imports and some LNG, no imports or supplements are expected to enter the U.S. gas transmission system in the West South Central region to replace the declining lower-48 production. Thus, the U.S. gas transmission system will have to undergo substantial changes to deliver gas to the various consuming lower-48 regions at the levels projected in the 1988 GRI Baseline Projection.

The need for this change will be further emphasized by shifts in regional demand patterns. In the 1988 baseline projection, 92 percent of the projected increase in gas consumption between 1987 and 2010 occurs in California and the Atlantic regions. The projected growth in these regions is sufficient to take gas consumption higher than the previous peak levels. The gas transmission patterns will have to undergo substantial changes to accommodate the projected shifts in supply and demand relationships.

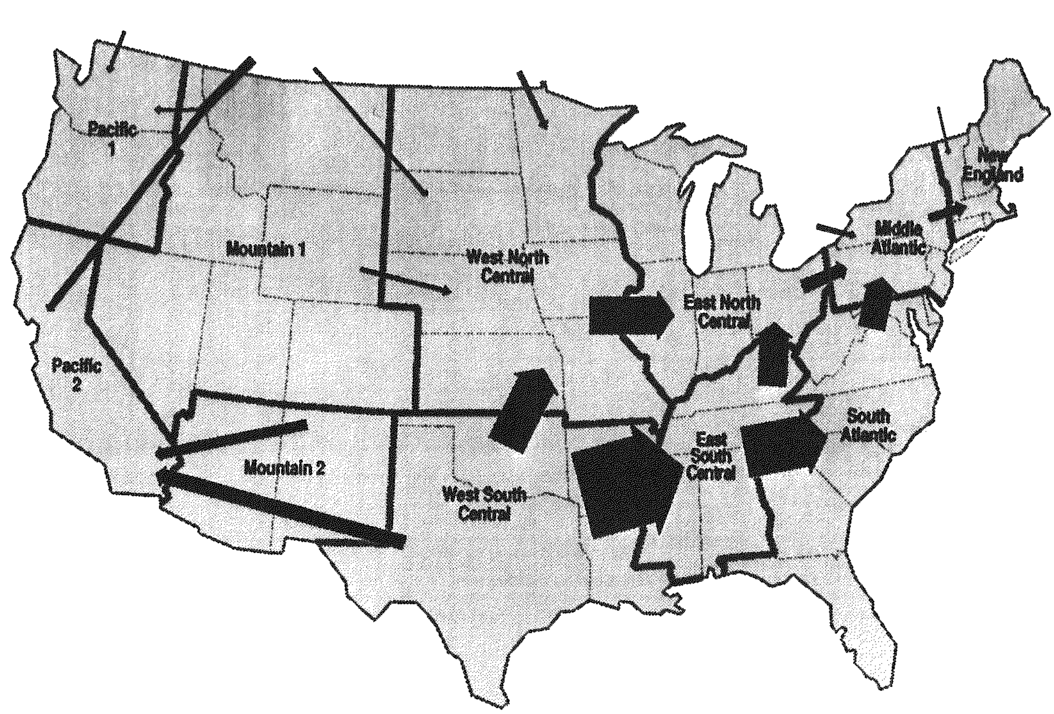
The shifts in the regional supply and demand shares in the lower-48 states will place an increasing burden on the lower-48 gas transmission system. New initiatives will have to be undertaken; new investments will ultimately have to be made to deal with these changes. Gas resources that are optimally situated to take advantage of these changes will increase in value.

Figure 1 shows the aggregate patterns that occurred in 1987. These aggregate patterns are meant to present the general net directional flows of gas in the lower-48 states between a net exporting supply region and a net importing end-use region. They are not meant to show the precise path the gas follows.

Figure 1 shows the centering of the lower-48 gas transmission system in the West South Central region in 1987. Only the Pacific Northwest region is not connected to this region. About 2.8 quads of gas were delivered to the North Central regions from the West South Central region, and 3.3 quads were delivered to the Atlantic region. Smaller amounts of gas were delivered from the West South Central region to the East South Central and the Pacific 2 regions.

The analysis assumes that the changes in the gas transmission patterns are determined by the relative proximity of the importing regions to the exporting regions. Thus, as the net export capability of the West South Central region declines, the decline first appears as a decline in deliveries to the West

Figure 1. Gas Transmission Patterns in 1987



North Central region. The proximity of the West North Central region to the growing exporting capability of the Mountain 1 region and western Canada compensates for this decline in deliveries from the West South Central region. Under this premise, the Atlantic and East South Central regions would be the last to experience the effects of the fall-off in the West South Central export capability.

As a result of these assumptions, the decline in West South Central export capability by 1995 principally appears as a decline in deliveries to the West North Central region. Gas deliveries to this region from the West South Central region in 1990 fall more than 40 percent relative to 1987. The decline in deliveries is compensated for by increased gas deliveries from the Mountain 1 region and Canada.

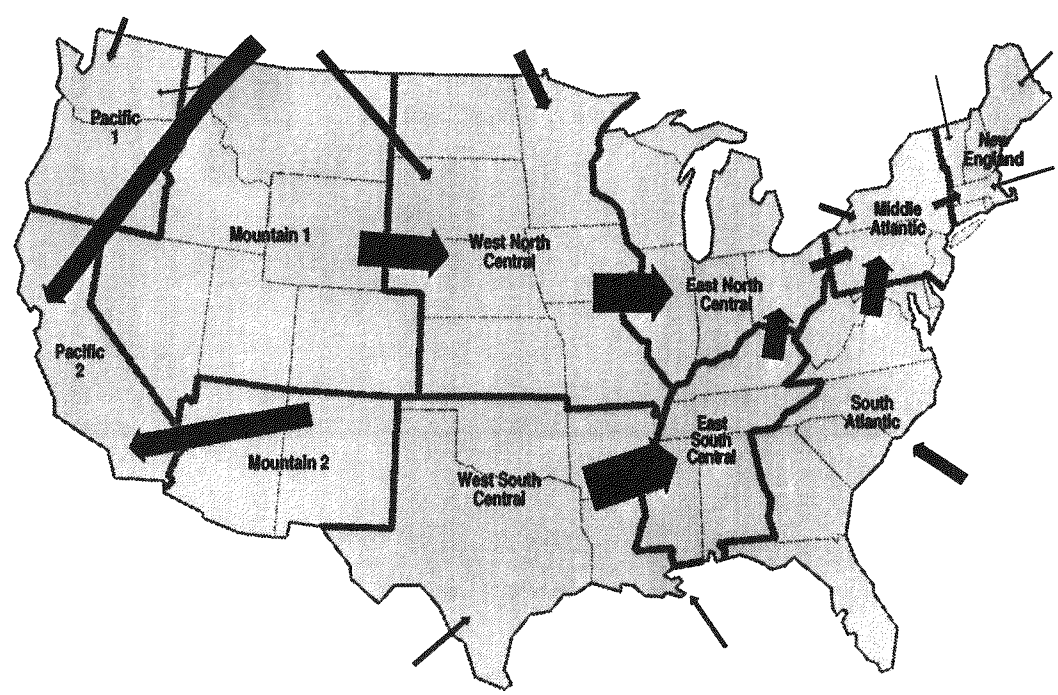
The shifts become increasingly visible after 2000 as production in the West South Central region continues to decline. The production in this region, however, does not include the effects of any production that would result from the improved recovery of gas from higher permeability gas reservoirs or associated gas from oil reserviors. The potential for this resource could be substantial and would slow substantially any decline in West South Central production. This, in turn, would slow the shifts in gas transmission patterns.

Without this incremental recovery from higher permeability reserviors, gas production in the West South Central region would decline such that all gas exported from the West South Central region would go to the East South Central region. Figure 2 shows the gas transmission patterns for the year 2010 that would result under these circumstances.

The figure shows that deliveries from the West South Central states to the West North Central region and California (Pacific 2) have disappeared. The major share of gas in the North Central regions is now obtained from the Mountain 1 region and Canada. The growth in gas consumption in the Atlantic states through the year 2010 is supplied through increased deliveries of gas from Canada, resumption of LNG deliveries, and increased gas production in the region. The increase in local production and imports offsets the substantial decline in deliveries from the West South Central region.

The U.S. gas transmission system will have to undergo significant changes to compensate for the regional shifts in gas supply and consumption. The changes could be particularly significant for parts of the Atlantic region due to its remoteness from the Mountain region and western Canada. Increased opportunities, therefore, could arise for increased deliveries of LNG into the Atlantic region and from lower-48 production sources that are located in or near the Atlantic region.

Figure 2. Gas Transmission Patterns in 2010



VI. Implications for Future Work

The production of the GRI baseline projection is an ongoing process. GRI modifies the projection to address changing energy market conditions, to provide new data to help in planning the GRI R&D program, and in response to comments received from users of the projection. In the *Gas Research Insights* publication summarizing the 1987 GRI Baseline Projection, progress in ongoing work was discussed and a number of other factors were identified as requiring study. The following work was completed and incorporated into the 1988 projection. Additional areas in which work is ongoing or which require study in the coming months are also identified.

Industrial Sector

Over the last decade, in response to changing energy prices, the availability of improved technologies, and due to increased foreign competition, the relationship between industrial output and energy consumption has changed significantly. In the 1987 projection, GRI updated the industrial sector data base based on data provided by Energy and Environmental Analysis, Inc. (EEA), in an attempt to reflect these changes. This was part of a continuing effort to improve the forecast of industrial energy consumption.

In the 1988 baseline projection we continued to revise the industrial sector methodology and data base based on data provided by EEA from their Industrial Sector Technology Use Model (ISTUM). In the 1988 projection we revised the base year (1985) energy consumption data by service and by standard industrial classification (SIC). Further, we updated the service demand coefficients in the model that relate industrial output to energy input by service.

In the 1989 baseline projection, GRI will continue to work on the industrial sector. Specifically, we will examine growth in industrial feedstock consumption of energy, look in detail at the continued projected strong growth in industrial coal consumption, continue to revise the industrial data base using information from EEA, and look at the implications of industrial fuel switching for natural gas and residual fuel oil consumption.

Gas Transportation Patterns

One of the implications identified in the 1988 baseline projection is that natural gas transportation could significantly shift between 1987 and 2010.

GRI plans to develop a better capability to assess the transportation and regional factors that will affect the outlook for gas supply and demand patterns. The potential changes in transportation patterns indicate that it is critical to assess gas supply on a regional basis.

The modification of the GRI Hydrocarbon Model to deal with the changing regional patterns of lower-48 gas supply and demand has begun. In the 1988 GRI Baseline Projection, the calculation of gas transportation charges now reflects the trends in the macroeconomic parameters (e.g., rates of return, interest rates) and the general trends in incremental investment to deal with the changes in gas transmission patterns.

The changing transmission patterns will lead to a growing disparity in gas wellhead prices among regions as competition shifts more to citygate prices. The model currently distinguishes resource costs on a regional basis but uses a single average lower-48 gas price. In the 1989 GRI Baseline Projection, gas wellhead prices will be developed on a regional basis. Work has begun to further modify the pipeline segment of the GRI Hydrocarbon Model to specifically allocate investment charges to particular pipeline bundles transporting natural gas between regions.

Natural Gas Resource Base

GRI constantly reviews the natural gas resource base used in the GRI baseline projection. The onshore lower-48 resource base used in the GRI Hydrocarbon Model has been updated to reflect the most recent discoveries. This update will also explicitly separate out the permeability gas component of the onshore lower-48 resource base. The offshore resource base will be updated in 1989. In addition, the treatment of technology effects on gas production will be expanded in 1989 for use in the 1990 baseline projection.

Electric Utility Sector

Over the last few years, GRI has worked on improving the electric utility methodology in the model. The result is an electric utility methodology that is comprehensive and provides a detailed projection of electric utility energy consumption. One enhancement in the data output from the projection that GRI is contemplating for the 1989 baseline projection is the reformatting of the output for both projected generating capacity and electricity demand into North American Electric Reliability Council (NERC) regions. The current model displays data from the projection in modified census divisions. These regions do not accurately reflect existing utility generating pools and do not reflect the type and direction of net regional electricity interchange. Reformatting the electric utility data into NERC regions will provide a better picture of the prospects for future electricity generation and utility energy consumption.

A major problem of long-term national energy models is that they tend to project average energy prices either for the United States as a whole or for large aggregate regions comprised of a number of states. Electricity prices during peak hours are comprised of energy and demand charges. The demand charges tend to make electric prices higher during peak hours than the average price for the region. If a particular appliance—for example, space-cooling systems—is used predominantly during peak hours, the relative competitiveness of the appliance is not accurately reflected by using average electricity prices. For purposes of evaluating specific GRI technologies, it is necessary to develop peak-hour electric prices as distinguished from the average price. The baseline projection currently only produces average electric prices by region. To resolve this problem in the 1989 projection, we plan to develop long-run and short-run marginal electricity prices to be used to distinguish between average and peak electric prices in evaluating the relative competitiveness of competing technologies.

Commercial Sector

In the 1987 GRI Baseline Projection a new commercial methodology was adopted that provided a more detailed projection of commercial energy consumption. Much of the work involved in developing this new methodology was the collection and construction of new data bases. Two of the key data sources used in developing these data bases was the DOE/EIA Non-Residential Building Energy Consumption Survey (NBECS) and an F.W.Dodge study of historical and projected (through 1995) commercial square footage. The Department of Energy recently released an update of the NBECS data that provides longitudinal data for the period from 1979 to 1983, and the F.W.Dodge study was recently updated. For the 1989 baseline projection GRI will examine the new data, compare it with the data being used in the projection data base, and make updates where appropriate.

Canadian Gas Imports

With the prospect for increasing U.S. gas demand, Canadian imports are projected to play a larger role in meeting U.S. gas supply requirements. As a result, the adequacy of the Canadian resource and the future availability of supplies to the U.S. is an important issue. In the 1987 baseline projection we noted that GRI was going to undertake a study to reexamine the assumptions concerning the availability of Canadian gas and possible constraints upon export volumes to the U.S. market. The results of this work have been included in the 1988 GRI Baseline Projection and are available from GRI in the publication *Canadian Natural Gas: Export Potential.*

Petroleum Refining

In late 1986 GRI undertook a study with Sobotka, Inc., to critically evaluate the petroleum refinery methodology used in the baseline projection. The intent of the analysis was to compare the result of the projection with those of a more detailed refinery industry optimization model and to suggest and describe how to implement updates to the current methodology, if necessary. Some of the work was incorporated in the 1987 baseline projection, specifically updates to the methodology used to develop residual fuel oil prices. However, as noted in the GRI *Insights* article on the 1987 projection, much of the work was not completed in time to be fully incorporated into the 1987 projection. The balance of the work suggested by Sobotka was included in the 1988 baseline projection. This included data base updates as well as the revision of the projection methodology. The new methodology produces petroleum product price projections that are more consistent with the specific economic and technical constraints found in today's refineries.

Despite the changes that have been adopted, the refinery methodology has two important limitations. First, the methodology is limited to the United States. The model assumes that petroleum product imports will be available on world markets when needed. Second, the current refinery configuration is not explicit enough to account for changes in refinery capacity, capacity utilization, product quality changes, and shifts in product demands. Recognizing these shortcomings, GRI is undertaking a study to update the refinery methodology to correct these deficiencies. The new refinery methodology will be used in producing the 1989 baseline projection if available in time.

Residential Sector

The space heating and cooling loads currently used in the baseline projection were adopted from estimates Data Resources, Inc., had been using in their Energy Model prior to GRI's development of the baseline projection. As part of GRI's evaluation of R&D projects, a comprehensive set of heating and cooling loads by region has been developed by GRI's Technology Analysis group in Chicago using a simulation model. As part of this work, the Technology Analysis group also developed electric appliance loads for each of the regions as well. Both the space heating and cooling load data and the electric appliance load data will be adopted in the 1989 baseline projection.

Appendix A
Baseline Projection Methodology

This appendix outlines the methodology used to produce the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand. A more complete paper discussing the methodology used to produce the 1987 baseline projection, *1987 GRI Baseline Projection Methodology*, is available upon request from GRI. Much of the methodology discussed in that paper is very similar to that used for the 1988 projection.

I. Introduction

Strategic planning of GRI's R&D program requires an appreciation of the outlook for national energy supply and demand and an estimate of the role that natural gas will play within that future. Another key element in GRI's R&D program planning is an assessment of the benefit that would accrue from the successful development of each individual research project being evaluated for funding. The development of a consistent framework that establishes a likely projection of future energy supply and demand is critical to this assessment process. The framework that forms the scenario and data base for these planning decisions is called the baseline projection.

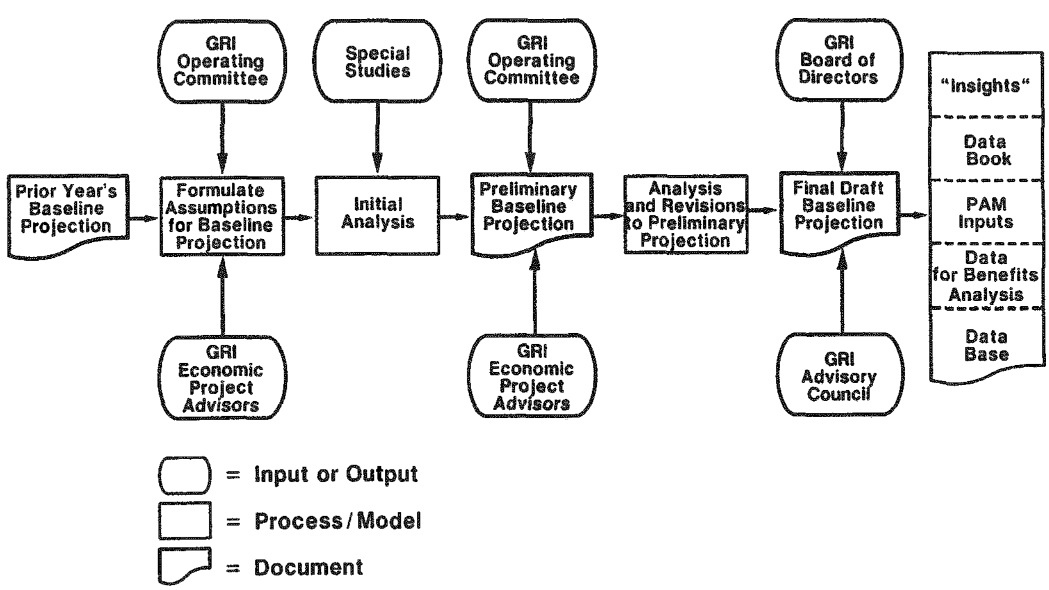
The baseline projection represents the GRI planning outlook for the economic and energy supply and demand situation to the year 2010. The 1988 projection was developed independently by GRI using publicly available data and a framework of commercially available models that GRI has modified over several years. It is not derived from the views of GRI member companies.

At GRI, we view the process of making the projection as being equal in significance to the results. The interactions with the organization:

1. Provide technical input from management, advisors, and technical staff;
2. Improve the understanding and acceptance of the results within GRI; and
3. Have become a part of GRI's strategic planning process.

Without these interactions, the analysis is a sterile exercise, which would probably end with a skeptical reception and with no real use in planning. The key interaction points in the projection process are shown in Figure A-1.

Figure A-1. Integrated Energy Projection—Methodology Process Flow



The key steps in producing the projection are as follows:

1. With the experience of the previous projection, the initial policy, economic, and major energy assumptions for the projection are developed in consultation with the GRI Operating Committee and various GRI advisory groups.

2. During the initial analysis, the results of special studies, data enhancements, and methodology updates are integrated into the overall methodology.

3. Interaction between the analysts developing the projection and the users of the projection are maintained at the technical level throughout the process.

4. The draft projection is presented to GRI's Operating Committee and project advisors for review. Additional revisions, as suggested by the Operating Committee and advisors, are incorporated before presentation to the GRI Board of Directors and Advisory Council for final approval.

5. The final results are disseminated throughout GRI and the energy industry through a series of publications and data bases, including: GRI *Insights* and Implications articles, the Data Book, as PAM inputs, as data for benefits analysis, and as support for other analytical studies.

The requirement for detailed backup for the 1988 GRI Baseline Projection dictates the use of complex models that can account for all the variables involved and conveniently generate consistent data tabulations.

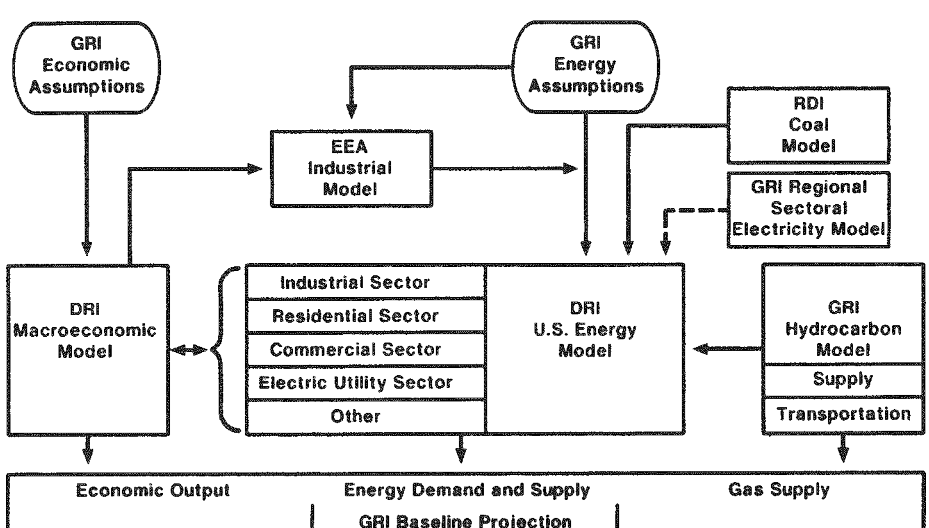
When GRI decided to develop an energy projection for use in planning, a decision was made not to develop a complete energy modeling structure from scratch. GRI instead decided to use existing models where available. In cases where GRI felt adequate models were not available, GRI built models to address specific aspects of energy markets of interest to GRI.

Three key models are used to develop the baseline projection. They include:

1. Data Resources, Inc. (DRI), Energy/Economic Modeling System
2. GRI Hydrocarbon Model
3. Energy and Environmental Analysis, Inc. (EEA), Industrial Sector Technology Use Model (ISTUM)

In addition to the major modeling structures used to produce the baseline projection, GRI has used and/or developed other models in special studies that have contributed to production of the baseline projection. These include the GRI Regional Sectoral Electricity Model and the Resource Data International (RDI) Coal Model. The composite modeling framework used by GRI to develop the GRI baseline projection is shown in Figure A-2.

Figure A-2. Composite Modeling Framework



EEA = Energy and Environmental Analysis, Inc.
DRI = Data Resources, Inc.
RDI = Resource Data International

The DRI, RDI, or EEA models are not adopted in their entirety as the GRI model. We use GRI assumptions and make extensive changes in model logic and equations. The GRI version of the DRI Energy Model includes many differences from the standard DRI model.

The following outlines the key models used to develop the projection.

II. DRI Energy/Economic Modeling System

The DRI Energy/Economic Modeling System was designed to reflect the interactions between the economic and energy sectors of the United States. The two main components of the DRI Energy/Economic Modeling System used by GRI are the Macroeconomic Model and the Energy Model.

A. Macroeconomic Model

The impact of energy markets on the economy are simulated in the DRI Macroeconomic Model through the dependence of key economic indicators upon energy supplies and prices. Gross national product (GNP), the relative prices of goods and services, and the trade balance are the major economic variables impacted by energy markets.

Gross National Product

The model relates GNP to capital, labor, energy supplies, and productivity. Inputs from the Energy Model impact GNP not only directly through changes in energy supplies but also indirectly through their impact on capital. Capital is negatively impacted by increases in energy prices, which lead to higher inflation and interest rates. Further, the available capital stock is reduced as higher energy prices force marginal capital out of productive use. The negative impacts on capital of higher energy prices may be partially offset by additional investments in alternative energy sources or investment in less energy-intensive production methods.

Inflation

Energy price changes are translated into changes in the product prices based on energy's relative importance in the production processes and on the ability of specific industries to pass cost increases through to consumers. Unit labor costs are impacted by energy prices through changes in labor productivity due to capital adjustments in response to the changing energy prices.

The relative energy intensity of specific products determines the extent to which relative product prices change due to energy price changes. Depending on the product's demand elasticity, shifts occur in final demand as a result of energy price changes. Changes in the demand mix lead to changes in industrial production, employment, and the investment mix.

Trade

An increase in either energy imports or OPEC prices raise the oil import bill. An increase in the oil import bill, in turn, causes a deterioration in the nominal trade balance and some depreciation in the U.S. dollar. To the extent that a dollar depreciation does occur, a further increase in real net exports will be induced, offsetting to some extent the decline in the nominal trade balance.

B. The Energy Model

The Energy Model used by GRI consists of submodels for each energy-consuming sector (residential, commercial, industrial, electric utility, and transportation) and a core model. The submodels determine the capital and energy mix decisions; the core model determines energy prices and sources of energy supply. In developing the GRI baseline projection, GRI also uses, to varying degrees, the DRI Drilling and World Oil Models. However, the major emphasis of GRI's work has been on updating and modifying the submodels and core model of the DRI Energy Model.

Energy Supply and Prices

A more detailed discussion of energy prices is presented in Appendix E. This section provides a short outline of the energy price and supply methodology with greater emphasis placed on the supply methodology.

1. Petroleum

a. Price

The Energy Core Model determines the price of petroleum products to end-users by tracking oil prices from the wellhead or their point of U.S. entry, to the refiner, to the wholesaler, and finally to the end-users. The taxes, transportation costs, refiner markups, and retailer markups applicable at each phase of petroleum supply are entered into the price calculations.

Petroleum product prices are based upon the average refiner acquisition cost of crude oil and assumptions regarding refiner markups that ensure that product revenues for the refinery slate of products cover refiner costs. Gasoline prices incorporate additional assumptions with respect to federal, state, and local taxes and retailer markups.

b. Supply

The supply of petroleum products is assumed to be equal to the demand for petroleum products. The model assumes that any excess of demand over domestic supply for crude and refined products will be met by imports. The level of domestic production comes from a simulation of the DRI Long-Term Drilling Model.

The Drilling Model projects both onshore and offshore production. Onshore exploratory drilling activity is determined by the expected profitability of finding and producing new oil reserves. Revenues generated by producing the reserves found by drilling depend on the expected price for hydrocarbons and the production profit of the reserves. The model assumes production will take place over a period of 10 years and that the total amount produced from the reserve depends on the reserve-to-production ratio. The crude price is provided by GRI. Natural gas prices, which impact the oil drilling decisions, are provided from the GRI Hydrocarbon Model. Oil prices are adjusted to net out taxes and royalties before the revenue calculations are made. The revenues are discounted to calculate a net present value of the revenues for the period in which the drilling takes place.

The costs of drilling and developing reserves, including the cost of dry holes, are calculated and discounted back to the period in which the exploratory drilling decision is made to create a net present discounted value of exploration and production costs. Dry hole and intangible expenses are taken in the year they occur. Tangible expenses are depreciated over the 10-year life of the reserves.

The level of exploratory drilling is determined by the level of the net present discounted cash flow from the production of the discovered reserves. Oil development is modeled as being dependent on prior years' exploratory drilling. Total oil well footage drilled is derived as the number of wells drilled multiplied by the average well depth.

Reserve additions are obtained by applying a finding rate to the calculated footage of oil wells drilled. The finding rate is determined as a function of the ultimate recoverable reserves, the cumulative reserves, and drilling to a given date in the model. Reserve additions are allocated to detailed reserve categories, using the Windfall Profits Tax (WPT) oil production categories.

Given the levels of proved reserves, production in a period depends on the reserves-to-production (R/P) ratios. The R/P ratios are projected by using historical trends and oil price information. An increase in real oil prices in the model leads to increased development drilling, which increases production from a given level of proved reserves, thus lowering the R/P ratio.

The offshore portion of the drilling model is driven by the level of offshore acreage under lease from the government. Expected ratios of exploratory wells to leased acreage determine the number of exploratory wells given a projection of acres under lease. Exploration is assumed to take place over a 5-year period: 40 percent in the period after the lease is obtained, 30 percent in the second period, 20 percent in the third period, and 10 percent in the fourth period. Development drilling activity is related to lagged exploratory drilling and the real oil prices.

Reserve additions are based on United States Geological Survey (U.S.G.S.) estimates of resource availability and development drilling activity. Finding rates for offshore oil are projected as a function of an exogenous initial finding rate, the ratio of cumulative acreage leased to the available sedimentary area, and a decline rate constant. Finding rates decline as the ratio of cumulative acreage to available reserves declines. Oil production is found by multiplying proven reserves by a R/P ratio for offshore oil reserves.

2. Natural Gas

The gas supply and price analysis is produced using the GRI Hydrocarbon Model. The GRI Hydrocarbon Model is comprised of the GRI Hydrocarbon Supply Model and the EEA Pipeline/Flowing Gas Model. The Hydrocarbon Supply Model deals with the exploration and production (E&P) of natural gas in the lower-48 states and offshore California and the Gulf of Mexico. The EEA Pipeline/Flowing Gas Model determines the acquisition cost and the transmission and distribution costs of natural gas delivered to end-users in 10 regions (DOE regions) in the United States. The pipeline model integrates assumptions developed by GRI about supplemental and imported gas supplies and the lower-48 conventional supplies projected by the GRI Hydrocarbon Supply Model.

A more detailed discussion of the GRI Hydrocarbon Supply Model and the EEA Pipeline/Flowing Gas Model is presented in Section III of this appendix, which explicitly discusses the GRI Hydrocarbon Model.

3. Coal

The coal price projection used in the 1988 GRI Baseline Projection was derived using the Resource Data International (RDI) Coal Model. The RDI Coal Model is a linear programming model that determines an optimum regional supply pattern for a given pattern of regional demands, which are determined in the Energy Model. Coal is assumed to be produced under conditions of increasing cost, and the supply equations minimize the total delivered cost of coal to all demand regions. The RDI Coal Model determines the regional marginal mine-mouth coal prices based on the total economic cost of production from a new mine.

4. Renewables

The supply and demand for renewable energy sources are handled as exogenous assumptions in the GRI Baseline Projection. The assumptions are developed by GRI in an offline calculation and input to the Energy Model. Renewable energy is assumed to play a role in energy supply in the residential, commercial, industrial, and electric utility sectors.

In the residential sector, renewable energy sources include energy from wood and solar power. Wood consumption represents a net addition to residential energy demand. Solar power, on the other hand, is assumed to displace conventional energy consumption. The consumption of electricity, natural gas, and fuel oil is reduced by the energy supplied from solar power. Each conventional fuel demand is reduced by an amount proportional to its share in the total residential demand for conventional fuels.

Wood and solar power are the most significant sources of renewable energy supply in the commercial sector. As will be explained more thoroughly in the section on renewable energy use in the electric utility sector, municipal refuse powered electric generation is assumed to be owned by the municipalities, although the power is assumed to be dispatched by the utility companies.

There are three categories of renewable energy sources used in the industrial sector: solar, wood, and other renewable (geothermal heat and low-head hydro used onsite). The supply of renewable energy sources to the industrial sector is treated as an exogenous increase in the demand for industrial energy. The industrial model includes conventional, industrially-owned, hydropower as a conventional power source. Along with cogeneration, hydropower electricity generated by the industrial sector for its own use is subtracted from the regional industrial electricity demands in calculating industrial demands for electricity from the investor-owned and public electric utilities.

The electric utility submodel has the most complete analysis of the role of renewables in the Energy Model. GRI supplies assumptions for renewable generation capacity in each region of the country. Capacities are given for low-head hydro, geothermal, wood, refuse, and a miscellaneous category of generation that includes wind and solar. GRI also supplies the capacity utilization rate for renewable generation.

Renewable generation sources are dispatched by the production planning portion of the electric utility submodel. In this way, the model accurately reflects the impact of renewable fuels on the demand for conventional generation fuels. The model dispatches renewable generation resources before the conventional fuels.

Renewable generation capacity is added into the total regional capacity calculation that is used to determine the need for new capacity and forms a part of the regional data base.

Energy Demand

A relatively small number of methodology changes were made in the demand analysis for the 1988 baseline projection. Much of the work on the 1988 projection involved fine-tuning the large number of significant updates adopted in the 1987 projection and producing a series of alternative sensitivities. However, a number of revisions were made in the demand model, including:

- GRI continued to revise the industrial sector methodology and data base based on data provided by EEA from their Industrial Sector Technology Use Model (ISTUM). In the 1988 projection, we revised the base-year (1985) energy consumption data by service and by standard industrial classification (SIC). Further, we updated the service demand coefficients in the model that relate industrial output to energy input by service.
- In late 1986, GRI undertook a study with Sobotka, Inc., to critically evaluate the petroleum refinery methodology used in the baseline projection. The intent of the analysis was to compare the result of the projection with those of a more detailed refinery industry optimization model and to suggest and describe how to implement updates to the current methodology, if necessary. Some of the work was incorporated in the 1987 baseline projection, specifically updates to the methodology used to develop residual fuel oil prices. However, as noted in the GRI *Insights* article on the 1987 projection, much of the work was not completed in time to be fully incorporated into the 1987 projection. The balance of the work suggested by Sobotka was included in the 1988 baseline projection. This included data base updates as well as the revision of the projection methodology. The new methodology produces petroleum product price projections that are more consistent with the specific economic and technical constraints found in today's refineries.

In many cases, minor updates made in the 1988 projection of previously made methodology changes proved to have a significant impact on the projection. Particularly important were updates in the methodology used to project commercial square footage, the handling of peak electric generating loads, and the future potential for hydro electric generating capacity utilization.

The following discussion will present a detailed outline of the methodology used to develop the demand projections for each sector in the 1988 baseline projection.

1. Residential Sector

The demand for energy in the residential sector is modeled in a two-step procedure. In the first step, a technology-based analysis of the growth in the stock of energy-using equipment is produced. The growth in the requirements for new and replacement heating, cooling, and water heating units in the residential sector is calculated, along with the growth in the stock of other household appliances (refrigerators, freezers, dishwashers, clothes washers and dryers, and cooling equipment).

The analysis is done for single- and multi-family homes in each of the 11 regions considered in the projection. New and replacement demands for heating and cooling equipment are met by a slate of competing technologies, with each technology's share in the market for new and replacement equipment determined through a modified life-cycle cost algorithm. The competing technologies are listed in Table A-1.

Table A-1. Competing Residential Heating and Cooling Technologies

Heating and Cooling	Heating Only
Electric Heat Pump	–
Gas Heat Pump	–
Gas Furnace/Electric Air Conditioner	Gas Furnace
Oil Furnace/Electric Air Conditioner	Oil Furnace
Electric Resistance Heater/Electric Air Conditioner	Electric Resistance Heater

After computing the stocks of appliances by fuel type, the model sums the single- and multi-family stocks to create appliance stocks for all homes in each region for gas, oil, and electric end-uses. Each appliance stock category is multiplied by an average annual energy use for the appliance, and the resulting annual fuel use by appliance type is summed to form a fixed utilization measure of total residential energy demand by fuel type. The fixed use energy demand concept is used as an energy-weighted appliance stock measure in the core model.

The projection of residential energy demand by fuel type is calculated in the core model as a function of the energy-weighted appliance stock term for each fuel, the deflated nominal price of the fuel divided by the average efficiency of the appliance stock, and the deflated per capita income for the region being analyzed.

2. Commercial Sector

The commercial model projects energy consumption by fuel in eight building types for each of 11 regions in the United States. Each building type is further broken down into six size classifications (see Table A-2). The building floor space for each building type and region of the country is projected through 2010. An F.W.Dodge/DRI building stock study is used as the basis for the floor space projections. The study estimated floor space for 15 residential, industrial, and commercial building types for each county of the United States from 1970 through the second quarter of 1985. Based on the F.W.Dodge Construction Potential data, floor space estimates were projected through 1990. The data was aggregated from the 15 residential, industrial, and commercial types in the F.W.Dodge/DRI study to the eight commercial building types used in the baseline projection.

Table A-2. Commercial Building Types and Sizes

Buildings
Retail, Wholesale
Offices
Warehouses
Education
Hospitals
Hotels, Motels
Eating & Drinking Establishments
Miscellaneous

Median Size (sq ft)
5,000
17,500
37,500
80,000
200,000
500,000

Beyond 1990, the floor space estimates were projected using econometric relationships that relate the historical F.W.Dodge/DRI floor space estimates to a measure of the net stock of nonresidential building structures. A separate projection is done for each building type in each region.

After projecting the stock of commercial floor space by building type and region, the floor space is divided into the six size classifications. The size classification fractions were drawn from the 1979 Nonresidential Building Energy Consumption Survey (NBECS) study and are held constant over the projection period.

The second step in the process is the determination of energy service demands. The submodel determines the energy requirements of the commercial floor space associated with six end-uses: heating, cooling, water heating, lighting, other electric, and other gas applications. Heating, cooling and water heating requirements can be met using appliances that consume either natural gas, oil, or electricity. The remaining end-uses do not involve interfuel competition. The heating and cooling options are shown in Table A-3.

Table A-3. Commercial Space-Conditioning Technologies

<u>Heating Technologies</u>

Size 1-3[a]

- Electric heat pump
- Gas heat pump
- Gas furnace
- Oil furnace
- Electric resistance

Size 4-6[b]

- Gas boiler
- Oil boiler
- Electric Boiler

<u>Cooling Technologies</u>

Electric

- Direct expansion vapor compression
- Direct expansion (PTAC)
- Reciprocal chiller
- Centrifugal chiller
- Electric heat pump

Gas

- Advanced absorption
- Engine-driven chiller
- Gas heat pump

[a] *Buildings with a median size of 5,000 to 37,500 square feet.*
[b] *Buildings with a median size of 80,000 to 500,000 square feet.*

The third step involves modeling the interfuel competition process in meeting the energy service demands. The submodel determines the distribution of energy service demands by fuel types for heating and cooling requirements through a modified life-cycle costing algorithm. The algorithm calculates the present value of the cost of purchasing and operating a heating or a heating and cooling technology over its expected lifetime and allocates shares of the new and replacement heating and cooling requirements based on the calculated costs. The shares of the competing fuels meeting the new and replacement water-heating energy service demands are tied to the shares of the fuels meeting the heating and cooling requirements.

In the fourth and final step of the modeling process, energy input requirements by fuel are aggregated over the service demands to create a total energy input requirement for each of the major fuels. For each energy service, the energy input requirement calculation multiplies the square feet of floor space requiring the service by an energy utilization measure and a measure of the average conversion efficiency of the technologies using the fuel. A final calculation sums across the service demands by fuel type to produce a measure of total energy input requirement by fuel type in the commercial sector.

3. Industrial Sector

The industrial model projects industrial energy consumption through a detailed analysis of energy service requirements associated with the projections of industrial production from the macroeconomic projection. The analysis takes place in two steps—an interfuel competitive analysis is done with an end-use or process type model in the industrial submodel, and a total industrial fuel demand analysis is done in the core model using an econometric analysis.

The industrial submodel analyzes the demand for the major fuels, coal, gas, oil, and electricity, in 10 industries:

1. Food Products (SIC 20)
2. Pulp and Power (SIC 24)
3. Chemicals (SIC 28)
4. Refining (SIC 29)
5. Stone, Clay, and Glass (SIC 32)
6. Primary Metals (SIC 33)
7. Other Manufacturing
8. Agriculture (Farm Vehicles)
9. Construction (Construction Vehicles)
10. Mining.

There are nine industrial end-uses analyzed in the model:

1. Process steam
2. Indirect heat
3. Direct heat
4. Machine drive
5. Electrical services
6. Iron production
7. Farm vehicles
8. Construction vehicles
9. Mining.

The industrial submodel defines a projected level of output for each of the 10 industries used in the analysis based on macroeconomic projections of output indices and the real level of output in 1980. Production for each of the industries is allocated to the 11 regions. Regional production by industry is then converted into energy service requirements using coefficients developed and provided by EEA. Assuming fixed energy utilization rates, these energy service demands can proxy the stock of energy-using industrial equipment needed to produce the projected industrial output.

The portion of the process demands that represent new demands in each period is derived by differencing the total demand series after accounting for annual depreciation of the equipment satisfying the demands. The new industrial service demand that can be met by alternative fuels is distributed among the competing fuels on the basis of a life-cycle costing algorithm. Total process demands by fuel type are calculated as the sum of new process demands by fuel type and the stock of process demands from the previous period after accounting for depreciation (the process demands are used to proxy capital in place).

An average efficiency measure is calculated for the stock of process demands by fuel type. The efficiency calculation averages the exogenously specified efficiency of new technologies with the average efficiency of the stock of existing technologies in the previous period. The weights used to calculate the average efficiencies are the new process investments and the previous period's total stock of technologies by fuel type.

Total process demands by fuel type are created over the projection period by summing over the different processes met by each fuel and dividing each process demand by its average efficiency in each period. The resulting measures of industrial fuel consumption are passed to the core model where the total industrial demand for the fuels is projected. Total industrial demand for each fuel is projected using econometric specifications, which include the total fixed utilization process derived fuel demands as a proxy for the energy-using capital stock, the real efficiency-weighted price of the fuels, an industrial capacity utilization indicator, and an exogenously specified annual rate of nonprice conservation improvement.

4. Electric Utility Sector

The function of the electric utility submodel within the Energy Model is to determine end-use electricity prices for the residential, commercial, and industrial sectors and to calculate capacity and fuel requirements for the electric utility sector to meet the total generation requirements. The electric utility sector of the Energy Model consists of six major equation blocks and a capacity planning submodel. The major equation blocks include:

Energy Demand
Peak Demand
Capacity
Generation

Financial
Electricity Price.

The function of each equation block is outlined below.

a. Energy Demand

The energy demand equations calculate demand for both dispatched electric energy and nondispatched electric energy (in millions of kilowatt-hours). Electricity demand is the sum of demands from the commercial, industrial, residential, transportation, and electric utility sectors. Dispatched electric energy is a modified version of electricity demand that accounts for losses and nondispatched sources of electricity. Dispatched electric energy is subsequently used in the generation submodel to determine generation by fuel type.

Residential, commercial and industrial demands come from the core Energy Model and are based upon statistical and engineering factors. Transportation demand is defined as last year's transportation demand grown at the rate of real GNP. Utility demand for electricity is defined as a historically based percentage of the sum of residential, commercial and industrial demands.

b. Peak Demand

The peak demand equations calculate regional planning peak and dispatch peak, both in megawatts. Regional planning peak is a concept that captures the degree of regional utility coordination between the extremes of a coincident and noncoincident peak. If a region were fully coordinated, utilities would plan to meet the coincident peak, or the maximum coordinated regional demand. If a region is not coordinated at all, planners would focus on the noncoincident peak, or the sum of individual utility peak demands. The regional planning peak is thus a function of coincident and noncoincident peaks and the regional coordination factor. The coordination assumption in each region is based on historical data. Dispatch peak is defined as the intercept of the load duration curve that is used in the generation submodel to determine dispatch of capacity, generation share, and capacity utilization rates.

To determine the planning peak, the model first uses historical data from Standard and Poor's Utility Compustat II on investor-owned utility peaks and sales to determine noncoincident load factors. Then noncoincident load factors and National Electric Reliability Council (NERC) information on regional coincident load factors are combined via a weighted average based on regional coordination levels to yield a regional "planning" load factor that reflects varying degrees of regional coordination. NERC regions are adjusted to the 11 energy model regions. Second, the planning load factor is used along with historical energy demand and a retail loss factor to calculate a historical planning peak. Next, the historical planning peak is split among residential, commercial, and industrial classes according to class cost allocation factors based upon implied peak responsibility in existing rate structures. Finally, individual class peak data is combined with the data on projected class demand and retail electricity loss factors to derive the class load factor.

In the next step, the model determines a dispatch peak. First, a regional load factor is calculated from the planning peak and regional demand. Second, a dispatch peak is calculated from dispatched electric energy and nondispatched electric energy, both modified by the load factor from the previous step. The dispatch peak is adjusted to account for cogeneration and imports and exports. Regional cogeneration capacity, which is determined outside of the model, is modified by the percentage of cogeneration capacity out of total installed cogenerating capacity that is available at peak and the equivalent unit availability of that capacity. Exports and imports are calculated as the difference between nondispatched electric energy and cogeneration sales, as nondispatched electric energy is defined as the sum of net imports and cogeneration sales.

c. Capacity

The capacity equations calculate regional capacity in megawatts. Capacity is defined as the total of generating plant nameplate ratings in a given year. This quantity changes over time as a result of newly added plants, retired plants, and plant conversions. The model accounts for changes each year among the different fuel types. The following fuels are represented: coal, conventional hydro, hydro pumped storage, nuclear, oil, natural gas, and other (e.g., low head hydro, geothermal, wood, refuse, and miscellaneous).

Annual capacity over time is defined as the previous year's capacity plus additions, minus plant retirements. There are two types of additions—endogenous and exogenous. Exogenous additions are announced additions by utilities or third parties that are planned to go into service in a specified year. The announced additions are not included in the projection verbatim, but are adjusted for doubtful plant completions. Endogenous additions are determined in the capacity planning submodel, which is described below. Endogenous additions are calculated if there is a shortfall between existing capacity and the capacity requirement. The endogenous additions depend on the amount of lead time available, the size of the unit, and the financing constraints. These additions are combined with the previous year's capacity. Retirements are determined from utility plans for the first 10 years of the forecast and by analysis of retirement trends for the remainder of the forecast.

In the case of coal and oil, there are several alterations to the above capacity definition. To allow for capacity converted from oil to coal, converted oil capacity is subtracted (like retirements) from the previous year's oil/natural gas capacity. Due to derating, only 85 percent of the converted oil capacity is added to coal capacity.

Capacity for "other" fuels does not take the general capacity form described above. "Other" capacity is defined as the sum of low-head hydro, geothermal, wood, refuse and miscellaneous capacities in each year. "Other" capacity is defined exogenously to the projection.

The capacity block also calculates cogeneration capacity and western interregional dispatch capacity. Cogeneration capacity is defined as regional cogeneration sales (in kilowatt-hours) divided by the number of hours in a year. The average load of cogeneration is assumed to be firm. Interregional dispatch capacity keeps track of capacity from the Mountain 1, Mountain 2, and Pacific 1 regions to the Pacific 2 region. For exporting regions, this is capacity that is over and above what is needed for regional load.

Capacity Planning (Endogenous Capacity). The endogenous capacity planning equations "build" capacity (in megawatts) if there is a regional capacity shortfall. The model is based on the concept of a loadstep, which is defined as a segment of electric load that is most efficiently served by a particular set of generating technologies. The model calculates a capacity shortfall, determines which of the four loadsteps (base, low-intermediate, high-intermediate, peak) has the greatest capacity need, and adds an amount of capacity according to need. A separate routine, described in the Revenue Requirements section, determines the revenue requirement by potential plant type and fuel and selects the least-cost plant.

The capacity expansion process iterates through each loadstep. It first determines if there is an overall capacity shortfall sufficient to warrant the construction of additional capacity. Shortfall is defined as the difference between a capacity requirement (accounting for a reserve margin above peak demand) and existing capacity. The shortfall has to be greater than 100 megawatts to warrant construction. If this process needs to be repeated after one or more loadstep iterations, the model limits the maximum amount of regional endogenous capacity that can be built in any year.

If there is a sufficient capacity shortfall, capacity is built by loadstep. The loadstep with the greatest capacity shortfall is determined. Given sufficient lead time to build a plant, the revenue requirements routine determines levelized costs for plants within that particular loadstep. The model then selects the plant with the lowest levelized cost. Large coal-burning units that run constantly tend to have low variable costs. They are less cost-efficient if frequently turned off and on and tend to be the preferred candidates to supply baseload capacity. Smaller gas-fired units, on the other hand, are more cost-efficient under peak conditions because they are easier to start and more able to closely match peak needs.

The following plant types are candidate plants for each loadstep in the 1988 baseline projection:

Step	Name	Plant Types
1	Baseload	Purchased Power, Large Coal, Medium Coal, Small Coal, Natural Gas Combined Cycle
2	Low-Intermediate	Purchased Power, Medium Coal, Small Coal, Natural Gas Combined Cycle, Residual Combined Cycle
3	High-Intermediate	Purchased Power, Natural Gas Combined Cycle, Residual Combined Cycle
4	Peak	Purchased Power, Natural Gas Combined Cycle, Residual Combined Cycle, Combustion Turbine

If a plant is selected and there are no financial constraints, the number of lowest cost plants to fill the capacity shortfall is determined, and plants are built subject to a regional maximum capacity constraint. If financial constraints are binding, plants from the next loadstep are examined. The resulting capacity is added to endogenous and total capacity for that year.

After adding endogenous capacity, if there is still an overall capacity shortfall, then the above process is repeated for the other loadsteps.

Revenue Requirements. The revenue requirements submodel uses loadstep-specific plant information to compare generating technologies on a cost basis. To compare technologies, the submodel calculates fixed and variable costs, with fixed costs a function of plant in-service cost (the return of capital and the return on capital) and variable costs a function of fuel cost, expected plant factor costs, and operation and maintenance costs. Plant revenue requirements, in millions of dollars, and plant levelized cost, in dollars per kWh, are the end result of the revenue requirements equations. Levelized costs are used to compare the different technologies.

The fixed cost portion of the model calculates the return on capital. Revenue required is defined as the sum of return on ratebase, book depreciation, and taxes. Revenue requirements are then determined. Annual expenditures for the construction of a plant of a given technology depends upon the size of the plant, its direct cost per megawatt (including any modular construction), the plant construction expenditure pattern, and the inflation rate. In the case of modular construction, the construction expenditure pattern may have gaps instead of an even distribution. The accumulation of construction expenditures, less new plant in service, is represented as the quantity of direct expenses. Construction expenditures and direct expenses are based upon the nominal overnight project cost and do not include the cost of project financing.

Capital, which is required to finance the construction of new plants, has an opportunity cost that, in part, depends upon embedded and marginal capital costs. These are based on the plant construction phase and general rates of return for debt, preferred stock, and equity.

For a given investment vehicle, the cost of capital is defined as the rate of return times the vehicle's share of funds raised times the sum of that year's average annualized construction expenditures and the previous year's cumulative direct expenses and cost of capital. These costs are the allowance for funds used during construction (AFUDC). AFUDC is split between equity and debt because these two components have different opportunity costs and thus should be calculated separately.

After construction, a plant goes into service, depreciates, and is taxed. These quantities are tracked through the ratebase. In a given year, new plant is determined as a percentage of new plant in service for both direct expenses and AFUDC. Direct expenses and capitalized carrying costs are split for tax purposes. In the case of modular construction, some percentage of the plant may be put into service in a given year, and the remainder of the plant may be put into service several years later.

Net plant is determined as net plant in the last period minus depreciation plus new plant. Straight-line book depreciation for both direct expenses and AFUDC is the sum of the previous year's net plant (accounting for depreciation) and new plant, divided by the plant's remaining years.

Two forms of deferred taxes arise before the plant is put into service--one due to interest during construction, which is treated as an expense and is not capitalized for tax purposes, and the other due to accelerated tax depreciation schedules.

Deferred taxes from interest during construction arise when a utility takes an interest rate deduction when incurred but does not pass this on to customers because customers are not paying for plant under construction. The utility charges customers for taxes based on no deductions. This tax recovery accumulates until the plant is finished. The deduction is then spread over the life of the plant. The utility pays higher taxes than it charges the customers and makes up the difference from amortization of the cumulative balance.

Deferred taxes also arise from accelerated depreciation schedules. Since interest during construction is not capitalized for tax purposes, the tax basis for depreciation reflects only direct expenses. A utility pays taxes based upon tax depreciation charges. Tax depreciation is calculated on a 150 percent declining balance with switchover, and is technically defined as 150 percent of the difference between gross plant and the previous year's cumulative tax depreciation split over the tax life, or the same difference split over the remaining plant life.

When tax depreciation is greater than book depreciation, the utility has paid lower taxes than what it has charged the customer. These tax savings, or deferred taxes, grow and then decline as book depreciation becomes greater than tax depreciation.

Cumulative deferred income taxes are a liability and thus offset assets. These quantities are subtracted from net plant to calculate the ratebase because some assets are not financed by either equity or debt. The ratebase for each technology is found by adding new plant to last period's ratebase and subtracting depreciation and deferred taxes.

Return on ratebase is divided into three components: return on equity, dividends on preferred stock, and interest on debt. The return for each component is the product of the component's capitalization percent and the rate of return on the component times the ratebase for each technology.

Return on ratebase (except debt) and book depreciation less tax depreciation are taxed at the corporate marginal tax rate.

Finally, revenue requirements, expressed in millions of dollars, are calculated as the sum of book depreciation, return on ratebase, deferred tax depreciation, deferred taxes on interest during construction, and income taxes.

The per kilowatt-hour cost of a plant using each technology is a function of revenue requirements, fixed operation and maintenance costs, and variable costs including fuel costs and incremental O&M costs.

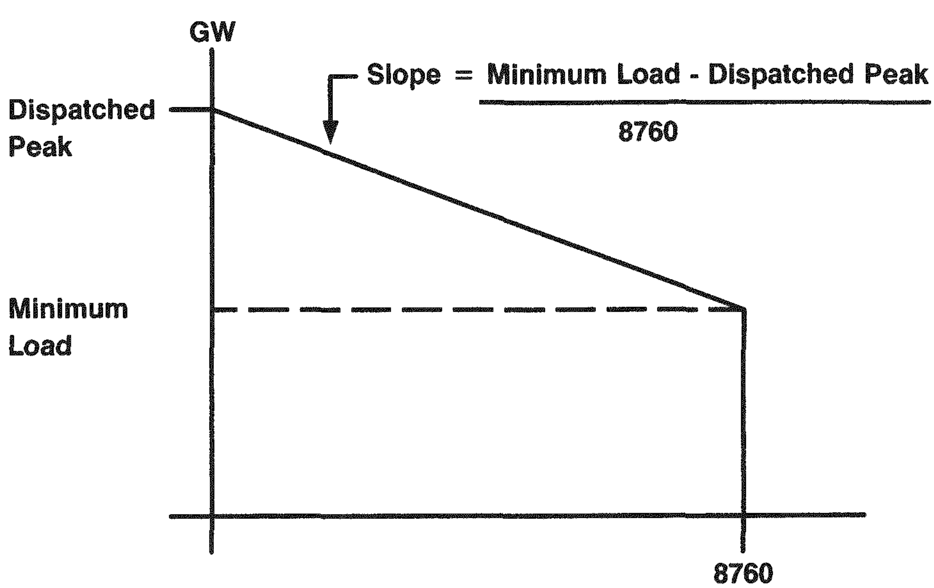
The levelized cost per kilowatt-hour is determined based upon the discounted present value of the cost per kWh over the life of the plant. An annuity with the same present value (equivalent time period and discount rate) provides the annual level payment. The level payment divided by expected annual kWh production yields the levelized cost per kWh.

d. Generation

The generation equations determine utilization of generating resources to meet electric loads. This information forms the basis for the projection of production costs and fuel demand. Incremental generation for each fuel, in millions of kilowatt-hours (gigawatt-hours), is derived from a load duration curve given the minimum-cost fuel dispatch order.

The minimum load level is determined by using a linear load duration curve as shown in Figure A-3. The area under the curve, dispatched electric energy, is known from the energy demand block. The intercept and dispatch peak have also been solved. The minimum load is the point on the y-axis where the load duration curve intersects 8760 hours. The minimum load is calculated as the only unknown from the areas of the triangle (above the minimum load line) and rectangle (below the minimum load line) comprising the load duration curve's area.

Figure A-3. Load Duration Curve



The load duration curve's slope is derived by using the standard equation for a line and the known points on the load duration curve.

Knowledge of the load duration curve's characteristics and knowledge of capacities derived from the capacity model are subsequently used to determine generation of electric energy by fuel type.

The next step in the process of determining generation shares adds derated capacities for each fuel from lowest to highest variable cost. Before derated capacities are determined, a peaking fuel share is calculated as one minus the percent of peak times the dispatch peak. Percent of peak is based on regional historical values. Peaking fuel share is subsequently used to reserve capacity for peak. Capacities for each fuel type are derated according to an equivalent unit availability (EUA). The EUA is one minus the percent of time units are down due to either forced outages or scheduled maintenance. Derated capacity represents the equivalent capacity available 100 percent of the time. Derated capacities for each fuel are then committed from lowest to highest variable cost in the following order: other, hydro, nuclear, coal, and oil and gas. Cumulative derated capacity is subsequently calculated as the addition of the derated capacity under consideration plus the derated capacities of all previously dispatched (lower variable cost) fuels. With the cumulative derated capacities determined, corresponding values for hours of generation can be found from the load duration curve, and the amount of generation for each fuel type can then be calculated.

In the West, there are interregional capacity exchanges from the Pacific 1, Mountain 1, and Mountain 2 regions to the Pacific 2 region. These exchanges are counted as cumulative derated capacity above that existing in the region. The interregional capacity is assumed to have a greater variable cost than Pacific 2 baseload, but a lower variable cost than oil and natural gas peaking units. It is therefore committed after baseload, but before oil and natural gas peaking unit. The interregional capacity is committed in the following regional order: Mountain 2, Pacific 1, Mountain 1. Interregional capacity is derated according to an interregional capacity equivalent unit availability factors.

The hours of generation for each fuel type are also determined using a simple linear equation. The slope of the load duration curve and the cumulative derated capacities are knowns; hours for each fuel is the unknown variable.

In the Pacific 2 region, hours for interregional sales are assumed to include the interregional capacity as described above.

Cumulative generation and incremental generation are determined next. Cumulative generation is the area on the load duration curve under each fuel's cumulative derated capacity line. In other words, it is the amount of generation by the fuel under consideration plus the generation of all previously dispatched fuels. If the cumulative derated capacity of the fuel under consideration is less than the minimum load level, then the area that measures cumulative generation is a rectangle—the product of the fuel's cumulative derated capacity and 8760 hours. If the cumulative derated capacity is greater than the minimum load level, then the area is the sum of the following three areas: 1) a rectangle—the product of minimum load and 8760 hours; 2) a rectangle—the product of the hours for the specified fuel and the difference between the fuel's cumulative derated capacity and the minimum load; and 3) a triangle with one side the same as the previously described rectangle side and the other side the difference between 8760 hours and the hours of the specified fuel.

Generation for each fuel type is determined by subtracting cumulative generation of the specified fuel from the cumulative generation of the previous fuel.

e. Financial

The financial equations calculate information that is subsequently used in the electricity price submodel. The explanation for these equations is divided into four parts—Ratebase, Fixed Cost, Common Stock, and Variable Cost. Ratebase explains the ratebase concept, including how the costs of new capacity additions are added into the ratebase. Fixed Cost describes how ratebase funding is split between debt and equity, and also between public and private investors. It explains how the rates of return on various funding sources are calculated. Common Stock explains the determination of stock oriented information from other information in the submodel. Variable Cost explains how certain operation and maintenance costs are calculated.

Ratebase. Ratebase, expressed in millions of dollars, is defined as the capital that is "used and useful" in the provision of electric service. Like capacity, ratebase changes over time as a result of the cost of new plants, conversions and life extensions. Transmission and distribution expenses increase the ratebase while depreciation decreases it. The financial block accounts for these changes in ratebase.

Ratebase additions includes the cost of endogenous and exogenous new plant from capacity additions, capacity with fuel conversions times the cost per megawatt of conversion, and capacity with life extension times the cost per megawatt of life extension. Ratebase decreases through depreciation, or at a depreciation rate times the previous year's ratebase and the current year's ratebase additions. The ratebase in the current year is the sum of last year's ratebase, ratebase additions, and depreciation.

Fixed Cost. This portion of the financial model determines external funds required, the capitalization structure, the rate of return for different types of funding, and the income tax expense.

External funding is calculated by assessing the sources and uses of funds. It is the amount of new capital required to bring the sources of funds into balance with the uses of funds. Internal funding is determined by the difference between other assets and an assumed minimum level of other assets required for working capital. External funding is subsequently split into investor-owned preferred stock, investor-owned equity, investor-owned debt, and public capital. Funding that is not met by preferred stock, common stock, or debt is assumed to be met by public capital. Each of these totals is then added to the previous year's balance.

To determine the return on ratebase for each funding vehicle, the ratebase is split between public and investor-owned based on the proportion of public or investor funding out of total funding.

The rates of return are determined for each funding vehicle based on econometrically estimated equations. The embedded long-term debt rate is based on the previous year's long-term debt rate combined with an adjustment based on the average yield on new issues of AA-rated corporate bonds. The preferred stock rate is based on the long-term debt rate. The rate for equity is also based on the average yield for corporate bonds. Public rate of return is based on the equity rate.

The return for each investor-owned funding vehicle is defined as last year's proportion of each vehicle times the average of last year's and this year's investor-owned ratebase times the embedded rate of return on the particular investment vehicle. In the case of public funding, the return is defined as the average of last year's and this year's public ratebase times the rate of return on public utilities.

Common Stock. The derivation of stock-related information is based upon the equity return on the ratebase. Investor-owned common earnings, in millions of dollars, are calculated as the sum of the equity return on the ratebase and allowance for funds used during construction. Investor-owned retained earnings are defined as investor-owned common earnings less dividends. Investor-owned cumulative retained earnings are defined as the previous year's cumulative retained earnings plus the current year's retained earnings. The amount of common stock outstanding is defined as investor-owned equity minus the current year's cumulative retained earnings. The number of common stock shares is defined as the number of last year's shares plus the increase in the amount of common stock outstanding between last year and the current year, divided by the previous year's price per share. Dividends per share on common stock outstanding are calculated as the product of the investor-owned common earnings and the payout ratio, divided by the number of common shares. Price per share is determined on a discounted cash flow basis and thus is defined as dividends per share divided by the common stock market rate of return. Earnings per share are defined as common earnings divided by the number of common stock shares.

Variable Cost. Operation and maintenance costs (excluding scrubbers) are calculated from a base value and maintained in real terms. These costs change in proportion to generation. The Pacific 2 region's O&M costs (excluding the cost of scrubbers) is calculated differently. In the Pacific 2 region, "other" and traditional O&M costs are separated. (Traditional is defined as total generation minus other generation.) In this region, O&M costs for "other" capacity costs are automatically increased 2 percent per year in real dollars. Traditional O&M costs are treated as they are in other regions. Transmission and distribution expenses in the United States are increased 5 percent per year in real dollars.

f. Electricity Price

The electricity price equations calculate average residential, commercial, and industrial electricity prices, in cents per kilowatt-hour. Electricity prices are calculated from demand and total electric utility revenue, which is the sum of the fixed, variable, and net interchange costs of electric production.

Fixed costs are costs that do not change with a change in electricity sales. They are defined as the sum of taxes, the equity return on ratebase, the debt return on ratebase, the preferred stock return on ratebase, the public capital return on ratebase, the cancelled nuclear cost, depreciation costs, and a ratebase adjustment factor. Most of these components are from the financial equations.

Variable costs are defined as the sum of operation and maintenance costs without scrubbers, the region's share of national coal scrubbing costs based on coal generation, and expenditures on each of the fuels used to generate electricity. Expenditures for each fuel are defined as demand for the fuel times the average price of that fuel in the region.

When an explicit cost of wholesale power is not present, an importing region's avoided cost is used. Net interchange includes the costs of cogeneration, interregional exchanges, and wholesale line losses. One component of net interchange, the price of cogeneration, is based on last year's avoided cost, and therefore is a function of last year's average electricity price adjusted for inflation and modified by the percentage of cogeneration price as a component of average price. Net interchange is defined as the sum of the following quantities: the difference between demand (adjusted for retail loss factor) and generation (including cogeneration sales, exchanges with Canada, and generation from refuse), times last year's variable cost divided by demand (regional exchanges vary with sales), all adjusted for inflation, the product of generation from refuse and cogeneration and the price of cogeneration, and the product of generation from Canada and the price of Canadian generation.

Fixed cost, variable cost, and interchange cost are summed to determine total electric utility revenues. Average electricity price is defined as the quotient of electric utility revenues and total electricity demand (adjusted to cents per kWh). Electricity prices are determined based on a cost allocation factor for each class. The cost allocation factor is a function of each class's peak responsibility and is used to allocate the fixed charges. Electricity price for each class is determined as the class's share of fixed costs per kilowatt-hour of electricity consumed by the class plus the average variable and avoided costs of electricity. Commercial, interdepartmental, and transportation electricity demands are all used in determining the average commercial electricity price.

5. Transportation

The transportation submodel projects transportation fuel demands for automobiles, trucks, and airplanes. Demands are projected for regular and unleaded gasoline, diesel fuel, and jet fuel. Natural gas used in the gas transmission process is also treated as a transportation fuel use. Finally, the transportation demands for bunker fuel, liquefied gases, aviation gasoline, electricity, and methane are also considered in this submodel.

a. Motor Vehicle Fuel Demands

The model incorporates a detailed analysis of auto and truck vehicle stocks, the economic and technical characteristics affecting the utilization of the stocks, and the efficiency ratings of the stocks.

The stocks of cars and trucks are modeled by adding the sales of cars and trucks in each projection period to the stocks of the previous period. Stocks are estimated for gasoline and diesel automobiles and for gasoline and diesel light-, heavy-, and medium-weight trucks. Exogenous survival rates are assumed for cars and trucks of vintages up to 10 years for cars and 15 years for trucks and for cars older than 10 years and trucks older than 15 years. Car sales for domestic and foreign cars and trucks are taken from the U.S. macroeconomic forecast and are split between diesel and gasoline sales by a share parameter related to the change in gasoline prices relative to a base case level of gasoline prices. As gasoline prices increase, the share of diesel engines will increase.

The average efficiency, in miles per gallon, of a period's stock of cars is calculated as the quotient of the expected miles driven by the stock of cars on the road in the period and the expected gallons of fuel used by the stock.

The expected miles driven by the stock of cars (trucks) in any period is the sum over the current and 10 (15) lagged periods of miles driven by the cars (trucks) sold in the period that survive to the current period. Each vintage of cars (trucks) has a survival rate and a usage rate associated with it. The survival and usage rates are based on data published by the Motor Vehicle Manufacturers Association. The same approach is taken to calculate the expected level of fuel consumption for the stock of cars (trucks) in each period. For each vintage of cars (trucks), the surviving number of cars (trucks) sold in the period is multiplied by the usage rate and divided by the average miles per gallon for the vintage.

Given the average efficiency of cars (trucks), the demand for motor fuels is calculated by dividing the vehicle miles traveled by the stock of cars (trucks) by the average efficiency of the stock of cars (trucks). Vehicle miles traveled by the stock of cars are modeled by relating the average miles traveled per car to the deflated price of gasoline and deflated per capita income. Vehicle miles traveled by trucks in each period are related to the deflated price of gasoline and deflated gross national product. Total demand for automobile fuels is shared between gasoline and diesel fuel based on the expected miles driven by type of fuel divided by the respective average efficiency. Total demand for truck fuels is shared between gasoline and diesel in a similar manner.

b. Other Transportation Fuel Demands

The demand for aviation jet fuels is determined by an analysis of commercial passenger and cargo flight activity and military fuel demands. In addition to projecting motor vehicle and aircraft demands for fuels, the transportation submodel projects the demands for residual fuel oil (bunker fuel), lubes and waxes, and electricity.

The use of natural gas as fuel by the natural gas pipeline industry is projected by the GRI Hydrocarbon Model as part of the gas supply analysis. The Transportation Submodel also contains an exogenously specified level of methane demands for use by motor vehicles.

III. GRI Hydrocarbon Model

The GRI Hydrocarbon Model is based on a highly detailed description of the lower-48 hydrocarbon resource base and the drilling and exploration activities to develop that resource base, linked to a description of the U.S. gas transportation system. The integrated hydrocarbon model structure provides natural gas acquisition prices, citygate prices, and regional burnertip prices, in addition to lower-48 supplies. The model also includes an enhanced recovery module (ERM) that calculates the effects of technology on the recovery of hydrocarbons-in-place. In the 1988 GRI Baseline Projection, effects of technology on gas production from Devonian shale and coalbed methane in the Black Warrior Basin of Alabama were calculated in the ERM. The description of the U.S. gas transportation system reflects the effects of interfuel competition and the long-term trends in gas transmission patterns and macroeconomic conditions on gas transportation charges.

A. Hydrocarbon Supply Model

In the Hydrocarbon Supply Model, the resource base, both discovered and undiscovered, is described on a field basis. The fields are characterized by type (oil and gas), size [20 average sizes ranging from 4000 barrels of oil equivalent (BOE) to 2.2 billion BOE], and location. Location is defined both geographically and by depth.

There are 12 onshore and 2 offshore geographical regions. The resource is further distributed by field depth onshore and water depth offshore. The onshore depth intervals are 0 to 5,000 feet, 5,000 to 10,000 feet, 10,000 to 15,000 feet, and greater than 15,000 feet. By dividing the resource into depth intervals, the model is able to resolve the ambiguity in the trends in finding rates per foot drilled that are critical components in addressing the trends in overall finding rates.

In the offshore regions, the resource is distinguished by water depth, rather than drilling depths, since the dominant cost factors come principally from water-depth-related factors. Offshore, the resource is distributed among up to four water depth intervals. In the Pacific offshore region, there are two water depth intervals: 0 to 600 feet and greater than 600 feet. In the Gulf offshore region, there are four water depth intervals: 0 to 40 meters (except the Norphlet trend offshore Alabama and Mississippi), 40 to 200 meters, 200 to 1000 meters, and the Norphlet trend.

The supply component of the GRI Hydrocarbon Model has been designed to project annual rates of hydrocarbon production, reserve additions, and costs for each region and depth interval. The model simulates exploratory drilling decisions. Exploratory drilling leads to the discovery of new fields and, over time, to reserve additions, development drilling, and production.

The GRI Hydrocarbon Model supply component calculates a levelized hydrocarbon resource cost sufficient to provide a specified minimum real rate of return after taxes. In the 1988 GRI Baseline Projection, a minimum 10 percent real rate of return is used.

Because the model treats exploration for both oil and gas as a single activity, exploration costs must be allocated in some manner between oil and gas in order for the resource costs of gas to be calculated. In the baseline projection analysis, exploration costs are allocated on a BOE basis. If, for example, an increment of exploratory drilling adds 40 million BOE of oil and 60 million BOE of gas, 40 percent of the exploration costs are allocated to oil and 60 percent are allocated to gas in calculating the resource cost of gas.

The availability of advanced technology for gas production from Devonian shale and coal seams in the Black Warrior Basin is explicitly calculated in the GRI Hydrocarbon Model ERM. In areas where there has been noticeable Devonian shale activity since 1981, advanced technology for Devonian shale is assumed to be available by the early- to mid-1990s. In the remaining Devonian shale areas, where there has been little or no activity, advanced technology is assumed to gradually expand through 2010. Advanced technology for coalbed methane production in the Black Warrior Basin is assumed to become available in the active areas by 1991. By the mid-1990s, advanced technology is available throughout the basin.

B. Hydrocarbon Model Transportation Component

The treatment of the U.S. gas transportation system was modified in the 1988 GRI Baseline Projection to reflect the macroeconomic trends underlying the projection and the general trends in gas transmission patterns. The gas transportation industry rates of return and interest costs track the trends in these parameters used in the GRI baseline projection macroceconomic outlook. The ratebase for the industry reflects the long-term trends in amortization of the exisitng investment and new investment as well as the estimated investment necessary to deal with the changing gas transmission patterns.

EEA Pipeline/Flowing Gas Model

The EEA Pipeline/Flowing Gas Model was integrated with the GRI Hydrocarbon Model for the first time in 1985. The model provides a framework to account for supplemental gas volumes and prices, flowing gas accounts and prices, transmission and distribution costs, and end-use prices by region and sector. The Pipeline/Flowing Gas Model represents the gas transmission sector through 12 composite pipeline systems. The pipelines link the 14 hydrocarbon supply model regions to 10 demand regions, within which citygate and end-use prices are calculated.

The 12 model pipeline systems are composites or aggregates of published data on actual pipeline systems. The pipelines were structured according to the following criteria:

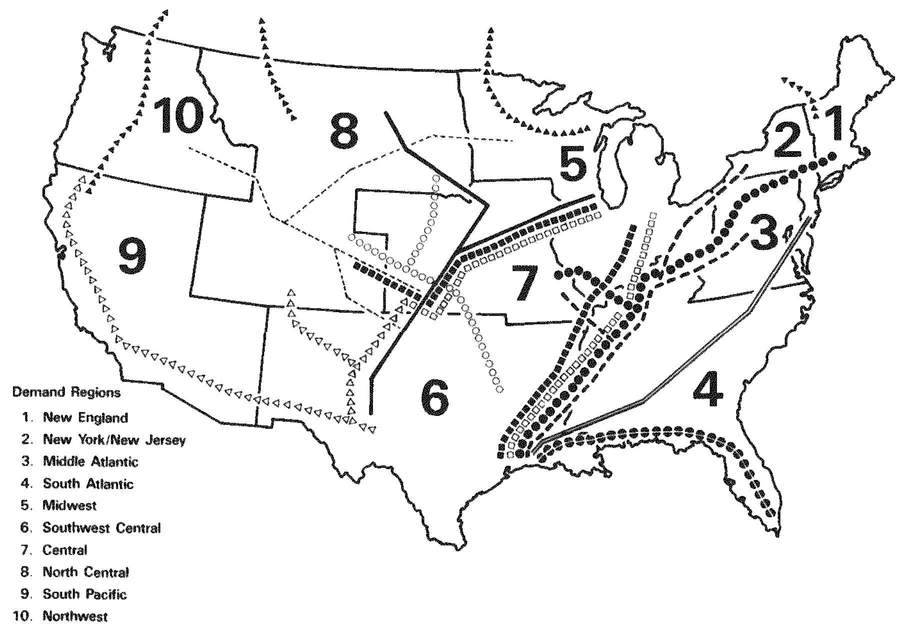
- Limit the number to reduce model complexity
- Ensure adequate coverage of pipeline to demand region patterns
- Distinguish where several major pipelines serve the same market areas
- Distinguish among key pipeline characteristics that may affect the national/regional gas market results.

The demand regions, within which the citygate and end-use demands are computed, are shown in Figure A-4, along with a schematic of the modeled pipeline groups. These demand regions correspond to the 10 Federal regions. The resulting end-use gas prices, gas acquisition prices, and delivered gas supplies to each region are transformed into the 11 demand regions used in the DRI Energy/Economic Modeling System.

The pipeline/flowing gas component of the GRI Hydrocarbon Model maintains a slate of supply sources for each of the 12 composite pipelines. This supply slate includes lower-48 natural gas production using base technologies or advanced technologies, pipeline imports, LNG, gas deliveries to the lower-48 states via the Alaska Natural Gas Transportation System (ANGTS), high-Btu gas from coal, and synthetic natural gas (SNG) from petroleum. For each source, the pipeline model tracks:

- Reserves
- Potential deliverability
- Pricing provisions (NGPA category, price redetermination provisions)
- Other contract terms (daily contract quantities, market-out provisions).

Figure A-4. Pipeline Systems and Demand Regions of the EEA/Pipeline Flowing Gas Model Used for the Baseline Projection



Details on contract prices and other terms and conditions are included to:

- Reflect the impact of critical issues such as resolution of indefinite price escalators
- Assess the impact of alternative contract pricing mechanism on future markets
- Distinguish wellhead cost differences among pipelines
- Depict competition between imports and domestic supplies.

The model's logic includes simplified surrogate pipeline "take strategies," or how pipelines would select supply sources from their potential inventory to meet a specified demand level. A given take strategy leads to an average acquisition cost of gas for each pipeline system. Fixed and variable transmission and distribution (T&D) costs are then added to yield citygate and burnertip prices for each demand region (aggregated distribution companies). The model uses the following approach for T&D costs:

- Transmission costs are based on fixed and variable cost components and are specific for each pipeline group.

- Distribution costs reflect recent rate differentials among end-use sectors (e.g., residential vs. industrial) using data for each of 10 aggregate distribution companies.

These rate algorithms are also structured to require full cost recovery. Thus, if demand levels fall, T&D costs per Mcf increase as fixed costs are spread over a smaller sales volume.

IV. EEA Industrial Sector Technology Use Model (ISTUM)

The EEA ISTUM is an energy demand model designed to evaluate industrial boiler and process heater fuel choices. Whereas the DRI Energy/Economic Modeling System uses an econometric framework, the EEA ISTUM uses a process engineering approach. The model considers new and existing boiler and process heating alternatives using engineering information and selects the capital and energy to be consumed based on the lowest expected life-cycle costs. The model analyzes technologies based on fuel prices, government energy and environmental policies, the costs associated with firing alternative fuels, and other technology-specific parameters.

GRI has not significantly altered the EEA ISTUM framework as it has the DRI model. The EEA model is given inputs consistent with the DRI modeling system and is used as a confirmatory tool to study the critical industrial sector fuel demand.

V. Producing the Projection

As a first step in producing the baseline projection, the initial policy, economic, and major energy assumptions for this projection were developed in consultation with the GRI Operating Committee. Important economic assumptions included GNP growth and inflation rates. Key energy assumptions included major fuel prices and certain energy quantities (e.g., the quantity of LNG imports).

The GRI energy assumptions and the necessary economic assumptions along with a first approximation of gas demand on a regional end-use basis were used in the GRI Hydrocarbon Model to develop preliminary supply and price trends for U.S. gas supply and the particular gas supply sources (e.g., lower-48 natural gas production, pipeline imports). These resulting regional supplies and prices were then used as assumptions in the Energy Model.

The Energy Model is used to develop a preliminary energy demand projection. The first step in using the Energy Model is the update of the historical data and the exogenous assumptions used in the model. The updates are based on DRI's spring energy projection and the new GRI assumptions. The DRI energy projection incorporates the results of DRI's Drilling Model. The GRI baseline projection uses only the oil supply results of the DRI Drilling Model. The gas supply projection is provided by EEA. Delivered coal prices are supplied by RDI.

After the Energy Model historical data is updated, GRI's initial exogenous assumptions are incorporated into the model along with the results of EEA's first pass at the prices and supplies of natural gas obtained from the GRI Hydrocarbon Model and EEA Pipeline/Flowing Gas Model. EEA provides the supply side of the baseline projection analysis of natural gas. The EEA delivered gas prices are incorporated in the Energy Model and help to determine the resulting demands for natural gas in the residential, commercial, industrial, and electric utility sectors of the economy. The initial set of gas demands used in EEA's gas supply and distribution model runs comes from the final set of gas demands from the previous year's baseline projection. GRI's assumptions for the refiner average acquisition cost of crude oil and the demand for renewable energy sources are also incorporated in the first run of the Energy Model.

The initial run of the Energy Model is reviewed by GRI and adjustments to basic assumptions are made as required. For example, in the electric utility sector, assumptions about the on-line dates for new coal and nuclear generating capacity are reviewed and adjusted to reflect GRI's views. GRI's analyses of factors such as the costs of the various types of new generating capacity and their retirement rates are also incorporated at this point.

EEA provides an analysis of industrial cogeneration for the baseline projection, using ISTUM. The ISTUM incorporates assumptions about industrial production and fuel prices that are supplied from prior runs of the Energy Model. GRI prepares a set of assumptions about cogeneration in the commercial sector.

After all of GRI's assumptions and analyses have been incorporated into the Energy Model, the resulting natural gas demands are passed to the EEA gas supply models, and a second round of delivered gas prices and supply availabilities is produced. The new gas data is passed back to the Energy Model, and another model solution is obtained. In the final analysis, a "near balance" is obtained between the demand for gas coming from the Energy Model, conditioned on the EEA supply analysis, and the supply of gas from the EEA analysis, conditioned on the Energy Model gas demands. Adjustments of supplies and demands to changes in the burnertip prices of gas lead the models toward mutual consistency.

The final step in the baseline projection involves the incorporation of GRI's macroeconomic assumptions. The Macroeconomic Model is resolved using the energy demands and prices from the latest solution of the Energy Model. GRI also incorporates its assumptions concerning near-term inflation and GNP movements. The resulting macroeconomic projection is used to put together the final solution of the Energy Model.

As pointed out earlier, the EEA ISTUM is used as a confirmatory tool. Inputs consistent with the GRI Energy Model runs were passed to the EEA model. These inputs included industrial energy prices and industrial economic growth rates. Assumptions used in the EEA model were set to coincide with those in the Energy Model. The ensuing EEA model results provided an additional analytical tool in evaluating the dynamics of industrial sector fuel choices. The preliminary baseline projection results were then presented to the GRI Operating Committee for review. Upon approval, the preliminary projection was presented to the GRI Board of Directors and Advisory Council. Using the modeling tools, this summary and the detailed backup tables, which are consistent with the economic and energy projection, were developed for use in strategic planning of the R&D program and for other analytical requirements within GRI.

VI. Contributions of Other Analyses

Aside from the formal model structures, another important part of producing the GRI baseline projection is the contribution of other analyses produced during each year. These analyses can be broken into three categories—those that develop a data base and, thus, provide data support for the baseline projection and for other GRI analyses; special studies that try to answer questions about specific issues of some importance to GRI and the gas industry; and methodology updates that try to improve the GRI modeling state-of-art by adapting the methodology to deal with changes in the energy and economic environment.

1. **Data Support:** Periodically, GRI has undertaken work to gather data for use in the modeling effort and in support of GRI's R&D program. Extensive data work has been done on the commercial and residential sectors.

2. **Special Studies:** Primarily one-time studies leading to a contractor report on a particular aspect of the energy situation. In these studies, we are seeking the expertise and proprietary information of outside consultants to help us evaluate an issue or factor that we believe is important to GRI's planning. We identify such issues as we watch the energy scene, prepare our projections, and respond to questions.

For example, we have recently completed a study of the outlook for Canadian gas supplies done for GRI by DataMetrics, Ltd., of Calgary, Alberta. This is a typical special study. With the prospect for increasing gas demand, Canadian imports will play a larger role in U.S. gas supplies. As a result, the adequacy of the Canadian resource and the availability of supplies becomes an important issue.

3. **Methodology Updates:** Production of the baseline projection is an evolutionary process. Since GRI began to produce the projection, we have continually sought to update the methodology to reflect changing energy and economic realities. As examples, the model has been modified to reflect the impact of increased sales of gas on transport or spot markets and we are currently examining the impacts of a move toward a more open electric generating market incorporating IPPs.

Appendix B

Industrial and Commercial Cogeneration

Cogeneration is the coproduction of useful thermal energy (steam, hot water, or hot gases) and power (mechanical or electrical) from a single source.* In the industrial sector, there are three basic technologies—boiler/steam turbines, combustion turbines with waste heat boilers, and combined cycles—that have been widely used for many years and have a high degree of reliability. In a boiler/steam turbine system, fossil fuels are consumed to generate high-pressure steam that is used to drive a turbine generator set producing electricity. The steam exits the turbine at reduced pressures and temperatures and is then used for process applications. In a combustion turbine system, electricity is generated by direct firing of fuel in a combustion turbine connected to a generator. The energy remaining in the high-temperature exhaust gases is then recovered in a waste heat boiler to produce process steam. Combined cycle systems are variations on the single combustion turbine system. The waste heat from the turbine is used to produce high-pressure steam that first generates more power through a steam turbine before exhausting to the process. The basic cogeneration technology used in the commercial sector consists of a reciprocating gas engine with heat recovery and a generator. Such systems can also include absorption cooling as an additional use for thermal energy. An alternative system still under development—the gas-fired fuel cell—will use an electrochemical process to produce electricity and heat.

Cogeneration has an important influence on energy consumption in the 1988 GRI Baseline Projection. Total cogeneration capacity is projected to grow at over 4.0 percent per year over the projection time frame. Gas is the major fuel used for cogeneration, and incremental consumption of natural gas for

Table B-1. Summary of Cogeneration in the 1988 GRI Baseline Projection

	Estimated 1987	1995	2000	2010
		Capacity (Megawatts)		
Industrial	20,209	26,955	30,898	43,993
Commercial	1,200	4,000	6,500	11,000
Total	21,409	30,955	37,398	54,993
		Cogenerated Electricity By Fuel Type (Billion kWh)		
Gas	66.7	115.5	149.1	195.3
Industrial	(57.7)	(87.5)	(103.6)	(123.8)
Commercial[a]	(9.0)	(28.0)	(45.5)	(71.5)
Coal	32.7	41.0	46.2	114.1
Oil	13.3	13.3	13.3	13.3
Other	37.7	46.9	53.2	56.7
Total	150.4	216.7	261.8	379.4
Sales to Utilities	35.3	51.2	53.0	64.5
Total Onsite Use	115.1	165.5	208.8	314.9
Industrial	(106.1)	(137.5)	(163.3)	(243.4)
Commercial[a]	(9.0)	(28.0)	(45.5)	(71.5)

[a] *All cogeneration in the commercial sector is assumed to be gas-fired and used onsite.*

* There are two possible cogeneration configurations: topping and bottoming cycles. In a topping cycle, the energy input is first used to produce power, and the rejected heat from power production is then used to provide useful thermal energy. A bottoming cycle reverses the sequence. Bottoming cycles normally utilize waste heat from an existing process and are unlikely to represent a significant market for natural gas.

cogeneration grows from 0.6 quad in 1987 to 1.7 quads by 2010. As a result of efficiency-based cost advantages and user concerns over the future reliability of centrally generated electricity, cogenerated electricity is projected to meet an increasing portion of electricity requirements over the projection. The percent share of total electricity demand provided by cogeneration increases from around 7 percent in 1987 to almost 12 percent by 2010. Tables B-1, B-2, and B-3 summarize the cogeneration projection in the 1988 GRI Baseline Projection.

Both the industrial and commercial cogeneration projections presented in the 1988 baseline projection are developed exogenously. The projection of industrial cogeneration is produced with the EEA ISTUM using assumptions consistent with the 1988 projection. A somewhat out-of-date, but more complete summary of industrial cogeneration is presented in a GRI report *Impact of Cogeneration on Gas Use in the Industrial and Electric Utility Sectors* (January 1986).

The commercial sector cogeneration projection is an in-house GRI projection derived from information provided by GRI's R&D group responsible for cogeneration and gas cooling. The estimate included in the 1988 projection is an exogenous calculation imposed upon the projection. Where an interaction between the demand for other energy forms and cogeneration could reasonably be expected, adjustment was made in the demand for other energy forms.

Table B-2. Percent of Total End-Use Electricity Demand Provided by Cogeneration

	Estimated 1987	1995	2000	2010
		Total Demand (Billion kWh)		
Industrial	946.2	1,152.7	1,269.3	1,522.0
Commercial	750.6	866.5	956.2	1,202.0
Total	1,696.8	2,019.2	2,225.5	2,724.0
		Percent of Total Demand		
Industrial	11.2	11.9	12.9	16.0
Commercial	1.2	3.2	4.8	5.9
Total	6.8	8.2	9.4	11.6

Table B-3. Incremental Fuel Consumption for Cogeneration[a] (Trillion Btu)

	Estimated 1987	1995	2000	2010
Gas[b]	615	1,051	1,333	1,704
Industrial	(543)	(853)	(1,021)	(1,235)
Commercial[c]	(72)	(198)	(312)	(469)
Coal	180	223	251	623
Oil	118	118	118	118
Other[d]	207	255	289	309
Total	1,120	1,647	1,991	2,754

[a] *In some situations, when a particular fuel is used in cogeneration it offsets the use of that fuel in another application. For example, the provision of space heating and cooling by a gas-fired commercial cogeneration system may offset gas consumption in a boiler or electricity consumption in a heat pump. This table reflects only incremental consumption, the net addition due to cogeneration.*

[b] *Does not include incremental gas consumed for electricity sold to utilities.*

[c] *All cogeneration in the commercial sector is assumed to be gas-fired.*

[d] *Off-line estimation assuming other energy consumption for cogeneration proportional to coal consumed in coal-fired cogeneration.*

The exogenous data included in the 1988 projection are based upon the assumed existence of four prototypical cogeneration systems—three engine-driven systems of 40, 150, and 300 kW, and a 200-kW fuel cell. Table B-4 presents the general specifications of the prototypical cogeneration systems included in the 1988 projection. Table B-5 presents the exogenous assumptions concerning the output of these systems.

Table B-4. General Specification of Cogeneration Systems[a]

	Engine/Generator With Heat Recovery	45-ton Absorp. Chiller Engine/Generator	90-ton Absorp. Chiller Engine/Generator	Fuel Cell
Size, kW	30	150	300	200
Utilization, hr	6000	6000	8600	6000[b]
Heat Output, Btu/hr	210,000	910,000	1,450,000	850,000
Efficiency				
Thermal, %	54	50	45	44
Electrical, %	26	28	30	36
Cost				
Installed, $/kW	1100	1000	900	1000[c]
O&M, $/kWh	0.015	0.01	0.007	0.005
Thermal Use				
Cooling, %	0	35	40	0
Water Heating, %	30	15	20	60
Space Heating, %	70	50	40	40
Electricity Use				
Lighting, Etc., %	100	100	100	100

[a] *System specifications are mid-life specifications and assume no improvement over time.*
[b] *The fuel cell actually operates continuously. This represents the full load equivalent.*
[c] *Represents cost at mature stage.*

Table B-5. Exogenous Assumptions Concerning Commercial Cogeneration

	Estimated 1987	1990	1995	2000	2010
Capacity, MW[a]	1200	2250	4000	6500	11000
Avg. Hours Utilization/Year	7500	7500	7000	7000	6500
Energy Output, 10^{12} Btu					
Electrical	30.7	57.5	95.5	155.2	244.0
Thermal	49.4	77.2	122.3	191.0	283.0
Thermal/Electrical	1.61	1.34	1.28	1.23	1.16
Avg. Electric Efficiency, %	29	32	34	35	37
Natural Gas Input, 10^{12} Btu	105.9	179.7	280.9	443.4	659.5
Fuel Displaced, 10^{12} Btu					
Natural Gas	34.3	55.0	83.4	131.1	190.9
Oil	12.0	18.3	25.3	36.0	44.8
Electricity	28.5	61.5	101.9	165.2	258.8

[a] *Assumes 350 MW added per year between 1987 and 1995, 500 MW between 1995 and 2000, 450 MW between 2000 and 2010.*

Appendix C

Comparison with the Prior Year's Projection

The production of the GRI baseline projection is an ongoing process. GRI modifies the model methodology and assumptions annually to adopt results of economic research, to reflect current energy market trends, and to recognize new historical data. The external events of 1987 were relatively consistent with the expectations incorporated in the 1987 GRI Baseline Projection. As a result, relative to the 1987 projection a small number of major changes were made in the 1988 baseline projection. The small number of changes permitted us to fine-tune the large number of updates that were adopted in the 1987 projection.

As part of producing the 1988 projection, GRI also developed a limited number of alternative sensitivities and one alternative scenario. The sensitivities run on the 1988 baseline projection included:

1. Two alternative energy price cases--High Energy Prices and Low Energy Prices--based upon the oil price outlook.
2. Two cases involving average annual rates of economic growth lower, 1.8 percent (Low Economic Growth case), and higher, 2.6 percent (High Economic Growth case), than the baseline projection rate of 2.3 percent.
3. A High Electricity Price sensitivity case in which electricity rates were increased by 25 percent.
4. A Service Sector Emphasis case with a structural shift toward the service sector of the economy and away from capital goods that exceeds the trend reflected in the baseline.
5. An Economic Cycles case in which the assumption of repeated "normal" or average economic cycles is altered to reflect the more erratic and severe economic disruptions that have historically impacted the economy.

The premise of the one alternative scenario is that the increased emphasis on a solution to environmental problems would be reflected in near-term public policy initiatives and that the current abundance of natural gas supply would encourage extensive use of natural gas for environmental purposes. The alternative future projections and the implications arising from them are discussed in the *GRI Insights* "Alternative Futures to the 1988 GRI Baseline Projection."

While a large number of methodology changes were not made in the 1988 baseline projection, some important improvements were made and are described below.

Industrial Data Base

In the 1988 baseline projection we continued to revise the industrial sector methodology and data base based on data provided by EEA from their Industrial Sector Technology Use Model (ISTUM). In the 1988 projection we revised the base-year (1985) energy consumption data by service and by standard industrial classification (SIC). Further, we updated the service demand coefficients in the model that relate industrial output to energy input by service.

Gas Transportation Patterns

In the 1988 GRI Baseline Projection, the calculation of gas transportation charges was modified to better reflect the trends in the macroeconomic parameters (rates of return, interest rates) and the general trends in incremental investment to deal with the changes in gas transmission patterns. This is a preliminary step toward analyzing the changing natural gas transportation patterns expected in the future.

Natural Gas Resource Base

GRI constantly reviews the natural gas resource base used in the GRI baseline projection. The onshore lower-48 resource base used in the GRI Hydrocarbon Model has been updated to reflect recent exploratory experience.

Canadian Gas Imports

With the prospect for increasing U.S. gas demand, Canadian imports are projected to play a larger role in meeting U.S. gas supply requirements. As a result, the adequacy of the Canadian resource and the future availability of supplies to the U.S. is an important issue. In the 1987 baseline projection we noted that GRI was going to undertake a study to reexamine the assumptions concerning the availability of Canadian gas and possible constraints upon export volumes to the U.S. market. The results of this work have been used to validate the estimates of Canadian imports in the 1988 GRI Baseline Projection and are available from GRI in a publication titled *Canadian Natural Gas: Export Potential.*

Petroleum Refining

In late 1986 GRI undertook a study with Sobotka, Inc., to critically evaluate the petroleum refinery methodology used in the baseline projection. The intent of the analysis was to compare the results of the projection with those of a more detailed refinery industry optimization model and to suggest and describe how to implement updates to the current methodology if necessary. Some of the work was incorporated in the 1987 baseline projection, specifically, updates to the methodology used to develop residual fuel oil prices. However, as noted in the GRI *Insights* article on the 1987 projection, much of the work was not completed in time to be fully incorporated into the 1987 projection. The balance of the work suggested by Sobotka was included in the 1988 baseline projection. This included data base updates as well as the revision to projection methodology. The new methodology produces petroleum product price projections that are more consistent with the specific economic and technical constraints found in today's refineries.

In addition to the important methodological changes discussed above, a large number of other important changes were made in the 1988 projection. This includes changes in response to comments and suggestions received from users of the 1988 GRI Baseline Projection, as well as changes that reflect an additional year of historical experience.

One input to the 1988 GRI Baseline Projection that did not change very much was the projection of crude oil prices. Table C-1 compares the oil price tracks used in the 1987 and 1988 projections. All of these prices have been converted to 1987 dollars for comparability.

The oil price projection used in the baseline projection is developed in December of the year preceding the date of the baseline projection. The long-term price track of oil prices is chosen based on the long-term fundamentals of world oil supply and demand. Near-term oil price, however, is determined by the political actions of the producing and consuming nations. Consequently, there could be significant interim variation in oil prices through the mid-1990s. However, GRI continues to believe that the fundamentals of oil supply and demand dictate a long-term rise in oil prices.

Table C-1. Crude Oil Prices (1987$/bbl)

	1987 Projection	1988 Projection
1987	18.57	17.91 (Actual)
1995	23.21	23.25
2000	27.85	27.00
2010	42.29	42.25

The near-term oil price track used in the 1988 baseline projection is somewhat lower than that used in the 1987 projection to reflect a slightly slower price recovery than we had expected. The longer range projection is relatively consistent with last year's projection.

The assumption and methodology changes have conflicting impacts, particularly on the aggregate projection of gas consumption, and it is sometimes difficult to attribute the changes in total primary energy demand or primary gas demand between the 1987 and 1988 projections to specific causes. Some of the assumption changes, however, have very specific impacts on the projection of energy consumption in the particular end-use sectors. Therefore, it is possible to site specific reasons for some changes in the end-use sectors.

Tables C-2 and C-3 show a comparison of the 1987 and 1988 projections of primary energy consumption and gas demand by sector, respectively, in the years 1987, 1995, 2000, and 2010.

A. 1987 vs. 1988 Projections of Primary Energy Consumption

Table C-2. Primary Energy Consumption Comparison of 1987 and 1988 GRI Baseline Projections (Quads)

	Actual	1995		2000		2010	
	1987[a]	GRI 87	GRI 88	GRI 87	GRI 88	GRI 87	GRI 88
Petroleum	32.9	33.2	35.3	35.3	37.4	38.3	38.9
Gas[b,c]	17.5	18.0	18.3	18.5	18.6	18.9	19.0
(Total Gas Fuels)[d]	(17.6)	(18.2)	(18.6)	(18.8)	(18.9)	(19.3)	(19.4)
Coal	18.0	18.6	19.3	20.2	20.9	25.4	26.2
Nuclear	4.9	6.4	6.5	6.4	6.7	6.1	6.5
Hydro	3.0	4.2	3.5	4.4	3.5	4.5	3.6
Renewables[e]	3.0	3.3	3.6	3.9	4.3	5.2	5.6
Total	79.3	83.7	86.5	88.7	91.4	98.4	99.8

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*
[b] *Excludes synthetic gas from petroleum and coal.*
[c] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*
[d] *The 1987 projection includes 0.2, 0.3 and 0.4 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in 1995, 2000, and 2010, respectively. The 1988 projection includes 0.3 quad of "other" gas in each 1995 and 2000, and 0.4 quad in 2010.*
[e] *Includes geothermal, wood, solar, etc.*

Total

- When compared with the 1987 projection, the 1988 projection shows higher levels of total primary energy consumption in 1995, 2000, and 2010. This is largely the result of an increased projection of energy consumption in the industrial, electric utility, and transportation sectors. Industrial energy consumption increases as a result of revisions to the service requirements based on data from EEA. The increased level of electric utility energy consumption reflects higher projected levels of electricity consumption in all end-use sectors. The higher level of energy consumption in the transportation sector reflects projected less improvement in vehicle efficiency (MPG) in the 1988 projection.

Petroleum

- Petroleum consumption in the 1988 baseline projection is higher in all years than projected in the 1987 projection. The increase in primary petroleum consumption is accounted for by increased consumption in the electric utility and transportation sectors. The increase in the electric utility sector results from increased electric generating requirements and the improved handling of electric utility peak generating needs. Petroleum is the dominant fuel consumed in the transportation sector. The increase in the transportation sector petroleum consumption is due to the adoption of a more modest improvement in vehicle efficiency (MPG).

Natural Gas

- The biggest change in primary gas consumption between the 1987 and 1988 projections is a more optimistic outlook for gas consumption in the near term in the 1988 baseline projection when compared with the 1987 projection. Near-term gas consumption is higher in the residential, industrial, and electric utility sectors in the 1988 projection. Further, gas consumption remains higher in the electric utility and residential sectors through 2010 in the 1988 baseline projection.
- Much of the improved outlook reflects the adoption of an additional year of historical data—in particular, the recovery of gas demand in 1987 relative to the low levels of 1986. The near-term improvement

in industrial gas consumption also reflects the adjustment of base-year gas consumption data to correct for the perceived inaccuracy of EIA data that inadequately measures industrial gas purchases from spot markets.* The improved outlook in the electric utility sector, again, reflects the update of the modeling of how electric utilities meet peak generating requirements. The higher projected levels of gas consumption in the residential sector in the 1988 projection reflect the recognition of recently improving gas market share of new single-family homes in this sector.

Coal

- The increase in primary coal consumption is accounted for entirely by increased consumption in the electric utility sector and directly reflects the higher levels of electricity demand in the 1988 baseline projection when compared with the 1987 projection.

Renewables

- Renewable energy consumption is slightly higher in the 1988 projection when compared with the 1987 projection. The projection of renewable energy consumption is exogenous to the baseline projection modeling system. The assumption was updated for the 1988 baseline projection. The slightly higher levels in the 1988 baseline projection largely reflect revised published plans for new renewable energy consumption facilities.

B. 1987 vs. 1988 Projections of Gas Demand by Sector

Table C-3. Comparison of 1987 and 1988 GRI Baseline Projections of Gas Demand by Sector (Quads)

	Actual	1995		2000		2010	
	1987[a]	GRI 87	GRI 88	GRI 87	GRI 88	GRI 87	GRI 88
Residential	4.5[b]	4.4	4.6	4.3	4.6	4.1	4.4
Commercial	2.4[b]	3.1	2.6	3.5	2.7	3.9	3.0
Industrial[c]	7.3	7.3	7.5	7.1	7.1	6.8	6.9
Electric Generation	2.9	2.8	3.3	3.2	3.8	3.7	4.3
Transportation[d]	0.5	0.6	0.6	0.7	0.7	0.8	0.8
Total[e]	17.6	18.2	18.6	18.8	18.9	19.3	19.4

[a] *Taken from March 1988 DOE/EIA Monthly Energy Review (MER) published June 1988.*

[b] *Historical Energy Information Administration (EIA) statistics for 1987 do not disaggregate data for the residential and commercial sectors. Actual data for 1987 represents an estimated disaggregation of total commercial and residential energy consumption based on the historical shares in each sector.*

[c] *The 1987 base-year data has been adjusted to include transportation sales of gas of approximately 0.4 quad not reflected in DOE/EIA statistics available in the March 1988 MER. Immediately prior to printing the Insights, DOE/EIA substantially revised the 1987 natural gas statistics in the July 1988 MER. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.*

[d] *Includes 0.2 quad of demand by methane vehicles in 2010. The estimate of gas consumed in methane vehicles reflects the estimate of the A.G.A. Gas Demand Committee.*

[e] *The 1987 projection includes 0.2, 0.3 and 0.4 quad of "other" gas, primarily SNG from petroleum and miscellaneous gases, and high-Btu coal gas, in 1990, 2000, and 2010, respectively. The 1988 projection includes 0.3 quad of "other" gas in each 1995 and 2000, and 0.4 quad in 2010.*

* Immediately prior to printing the *Insights*, DOE/EIA substantially revised the 1987 and 1988 natural gas statistics in the July 1988 Monthly Energy Review. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.

Total

- In general, the projection presents a slightly more optimistic picture of gas consumption in all years of the projection. The lower projected level of gas consumption in the commercial sector is more than offset by increased gas consumption in the electricity utility and residential sectors.

Residential

- Residential sector gas consumption is projected to be slightly greater than that in the 1987 projection. Much of the increase is due to a more optimistic projection of residential gas consumption in the 1988 baseline projection through 1990 when compared with the 1987 projection. This reflects the improving market share for gas equipment in single-family homes over the last few years. The gas share of space heating in single-family homes has increased steadily from just under 40 percent in 1982 (39.9 percent) to almost 52 percent in 1987 (51.9 percent).

Commercial

- The commercial sector projection in the 1988 projection reflects a much lower level of growth in total energy demand than the 1987 projection. The lower level of growth in total energy demand results from the adoption of a revised estimate of commercial square footage in the 1988 baseline projection.

- Projected gas consumption is lower in the 1988 projection relative to the 1987 projection, at least partially due to the lower level of total commercial energy consumption. However, gas consumption is projected to decline more than proportionally to the decline in total energy consumption. Part of the reason for the smaller gas share of total energy consumption was a reduced estimate of gas-fired cogeneration. The cogeneration estimate is exogenous to the model and is provided by GRI's R&D staff. The estimate reflects their most recent estimate of gas consumption for commercial cogeneration.

Industrial

- One of the major changes made in the 1988 baseline projection was the rebenching of data in the industrial sector based on inputs from the EEA ISTUM. The 1988 projection of energy and gas consumption in the industrial sector reflects the impact of the updated data from the EEA ISTUM. However, it also reflects the revision of the base-year level of gas consumption. Base-year industrial gas demand was increased in the 1988 projection to reflect transportation gas sales that we felt were still not being adequately captured in EIA historical data published through June 1988. The revision of the base-year data added approximately 0.4 quad to the EIA published historical figures for industrial gas demand in 1987.*

Electric Utility

- The projected higher level of gas consumption in the electric utility sector results from the improvements in the modeling of utility load patterns. The 1988 projection does a better job of capturing energy consumption in both peak and intermediate loads than did the 1987 projection. Furthermore, the 1988 projection reflects a slightly higher utilization rate of oil- and gas-fired capacity after the late-1990s as electric utility reserve margins tighten.

Transportation

- Gas demand in the transportation sector is primarily associated with pipeline compressor use of gas. As in past years, it also includes some demand for gas by methane vehicles in the longer term. Methane vehicles add 150 trillion Btu by the year 2010. The projection of transportation gas consumption is identical in both the 1987 and 1988 baseline projections.

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* Immediately prior to printing the *Insights*, DOE/EIA substantially revised the 1987 and 1988 natural gas statistics in the July 1988 Monthly Energy Review. The revised data better accounts for transportation sales of natural gas. The new data will be adopted in subsequent baseline projections.

Appendix D

Key Economic Variables

An important driving force behind any energy demand and supply projection is the assumed economic environment. For purposes of strategic planning, GRI's primary interest is the energy projection. However, the impact of economic interactions with energy markets cannot be ignored in the methodology. Economic parameters also are critical to economic and financial studies of technology-specific costs and benefits.

The economic variables are projected using the DRI Macroeconomic Model with key assumptions concerning near-term economic growth and the inflation rate set by GRI. The macroeconomic projection is further influenced by GRI's assumptions about energy markets.

Table D-1 provides some of the key economic and demographic variables from the 1988 GRI Baseline Projection.

Table D-1. 1988 GRI Baseline Projection Economic Assumptions

	Actual 1987	1995	2000	2010
Economic Growth (Billions 1982$)				
Real GNP	3,816	4,564	5,148	6,415
Real Disposable Income	2,674	3,106	3,465	4,216
Inflation (1987 = 1)				
GNP Price Deflator	1.00	1.41	1.81	3.04
Consumer Price Index	1.00	1.47	1.88	3.23
Wholesale Price Index	1.00	1.44	1.85	3.20
Price Deflator—Durable Equipment	1.00	1.38	1.75	2.91
Wage Deflator	1.00	1.55	2.15	4.36
Interest Rates (%)				
Prime Interest Rate	8.2	8.8	8.8	8.8
Average Yield on New Issues of High-Grade Corporate Bonds	9.3	9.7	9.5	9.0
Average Yield on New Issues of AA Rated Corporate Utility Bonds	9.5	10.1	9.8	9.4
Mortgage Rates	9.3	10.2	10.0	9.6
Misc. Economic Activity				
New Additions To Housing Stock (Single- And Multi-Family, Millions of Units)	1.94	1.84	1.83	1.70
FRB Ind. Production Index (1987 = 1)	1.00	1.25	1.44	1.84
Demographic Information				
Population (Millions)	243.9	260.5	268.9	284.3

Appendix E

Energy Price Trends

A prerequisite to projecting future energy demand is energy prices. The impact of energy prices on energy demand in each energy end-use sector varies due to a number of factors, particularly in a long-term projection. These factors include fuel availability, physical and technical characteristics of fuels, fuel-using equipment capability, the time horizon under consideration, new equipment capital costs, government regulation, and the buyer's inherent perception of the fuel, to name a few. Thus, while energy prices have an influence, it is only one of a number of factors that impact current and future energy demand. As a result, the observed relation between energy price and demand does not always follow intuitive expectations.

In the short-term, with the capital plant in place, the user is essentially indifferent to the quality, or "form value," of the energy, and competition for marketshare is simply a question of delivered price. A prime example is fuel switching in dual-fueled industrial boilers. However, in other situations, particularly those where the capital decision is still under formation, other considerations—inherent advantages such as environmental quality, low capital cost options, the fuel characteristics needed for a particular applications (i.e., clean burning for direct heat processes) and the perception of future fuel prices and availability—play an equal role in determining the final fuel use decision. Even in these situations, however, there frequently are alternatives that at some price differential will be substituted. A current example of this second situation is the use of gas for environmental applications.

I. Energy Acquisition Costs

The energy acquisition costs of crude oil, natural gas, and coal in the 1988 GRI Baseline Projection were determined as the result of both exogenous assumptions and model outputs. The exogenous assumptions were developed from studies by GRI and others. Table E-1 presents the energy acquisition costs used in the 1988 projection.

Table E-1. 1988 GRI Baseline Projection of Average Acquisition Costs (1987$/MMBtu)

	Actual				% Change		
	1987	1995	2000	2010	1987-95	1995-2010	1987-2010
Crude Oil							
Average Refiner Acquisition Cost	3.09	4.01	4.66	7.28	3.3	4.1	3.8
Natural Gas							
Average Acquisition	1.71	2.91	3.60	6.14	6.9	5.1	5.7
Lower-48	1.67	2.86	3.54	6.05	7.0	5.1	5.8
Coal							
Mine-Mouth	0.93	1.03	1.13	1.39	1.3	2.0	1.8

A. Crude Oil

The methodology used to develop the oil price projection in the annual baseline projection is based upon consideration of three factors that will dominate the evolution of the U.S. and world petroleum markets during the near-, mid-, and long-term. In the near term, the emphasis is placed on the pricing preferences of the political and economic decisionmakers who collectively establish world oil prices. The midterm consideration accentuates the evolving supply and demand situation and the role of OPEC and non-OPEC oil production in the world market. Finally, in the long term, OPEC pricing strategies will dominate world oil prices as OPEC will again be receiving generally comfortable revenue streams and will be called upon to increase production each year.

Table E-1 shows the oil price projection adopted for the 1988 GRI Baseline Projection. The oil price track reflects the expectation that prices will firm rapidly from their recent low levels but then remain relatively stable. The average refiner acquisition cost (RAC) of crude is projected to reach $23 per barrel by 1995, $27 in 2000, and $42 in 2010 (all in 1987 dollars).

The annual baseline projection cycle is initiated by the development of an oil price projection in the early weeks of the new year. In the beginning of 1988, it was evident that despite the great amounts of currently shut-in oil production, which on the basis of variable costs could be profitable at prices near $10 per barrel, the political and economic decisionmakers who collectively establish world oil prices much prefer a price near $20 per barrel. For this reason, and not for any fundamental reasons of resource availability or costs of production, GRI expects oil prices to gradually increase in real terms to $20 per barrel by the early-1990s or until the current excess production capability begins to diminish significantly. Prices near $20 per barrel are judged to be relatively stable, having only moderate depressant effects on U.S. production and providing sufficient revenues to exporting nations to reduce political pressures for either significant price or production increases.

Table E-2 shows the resulting sources of world oil supply and demand through the year 2010, given the projected oil price track. Through 1995, the supply situation appears comfortable. The share of OPEC oil in non-communist world oil markets remains low by historical standards, and the United States sustains oil production levels in the range of 8 to 9 million barrels per day (MMBD).

Table E-2. 1988 GRI Baseline Projection of U.S. Energy Supply and Demand—World Oil Supply/Demand Balance (MMBD)

	Actual[a] 1987	1995	2000	2010
Consumption				
United States	15.96	17.73	18.70	19.44
Japan	4.51	4.40	4.56	5.00
Other OECD	14.56	15.24	15.69	17.20
Developing Countries	12.46	14.28	15.67	19.50
Total Free World	47.49	51.65	54.62	61.14
Centrally Planned Economies	13.75	14.72	15.45	17.56
Total World Consumption	61.24	66.37	70.07	78.70
Supply: Crude, Condensate & NGL Production				
United States	9.91	8.11	7.30	6.56
Other OECD	6.77	6.87	6.86	7.26
Non-OPEC Developing Countries	8.61	9.76	10.01	11.92
Subtotal Non-OPEC	25.29	24.74	24.17	25.74
OPEC				
Saudi Arabia	4.37	6.42	7.85	9.11
Iran	2.31	3.23	3.91	4.45
Iraq	2.09	3.40	4.10	4.52
Other OPEC	10.26	12.90	14.78	16.92
Subtotal OPEC	19.03	26.01	30.64	35.00
Total Free World	44.32	50.75	54.81	60.74
Centrally Planned Economies	15.88	15.62	15.25	17.96
Total World Production	60.20	66.37	70.06	78.70
Stock Change	-1.04	—	—	—

[a] *Statistical Review of World Energy, June 1988.*

Between 1995 and the year 2000, however, non-OPEC production is expected to decline as the relatively low oil prices of the late-1980s and early-1990s impede investment in petroleum development. New production originates primarily from the developing countries, such as Columbia and Pakistan, and from areas where development had been initiated prior to the oil price collapse of 1986. Low oil prices, even at $20 per barrel, are expected to encourage an increase in the global demand for transportation fuels, especially in the developing countries, and sustain and perhaps expand the consumption of residual fuel oil in stationary applications. As a result of the diminished share of non-OPEC oil in the world oil market, OPEC's role becomes increasingly significant. The probable effects of the tightening oil supply situation are reflected in the baseline projection by oil prices that increase at a real rate of 2.8 percent per year in the midterm, that is, 1990 to the year 2000.

The last consideration is the nature of the long-term (beyond the year 2000) pricing strategy that will be adopted by the oil-exporting producers once they are again receiving generally comfortable revenue streams and are being called upon to increase production each year. As indicated in Table E-2, by the year 2000 non-OPEC production, including natural gas plant liquids, is expected to decline by over 1 MMBD from the 1987 production level of 25 MMBD. Concurrently, non-communist world oil demand is expected to increase by over 8 MMBD. Consequently, OPEC will supply 56 percent of the non-communist world oil in 2000, amounting to over 30 MMBD.

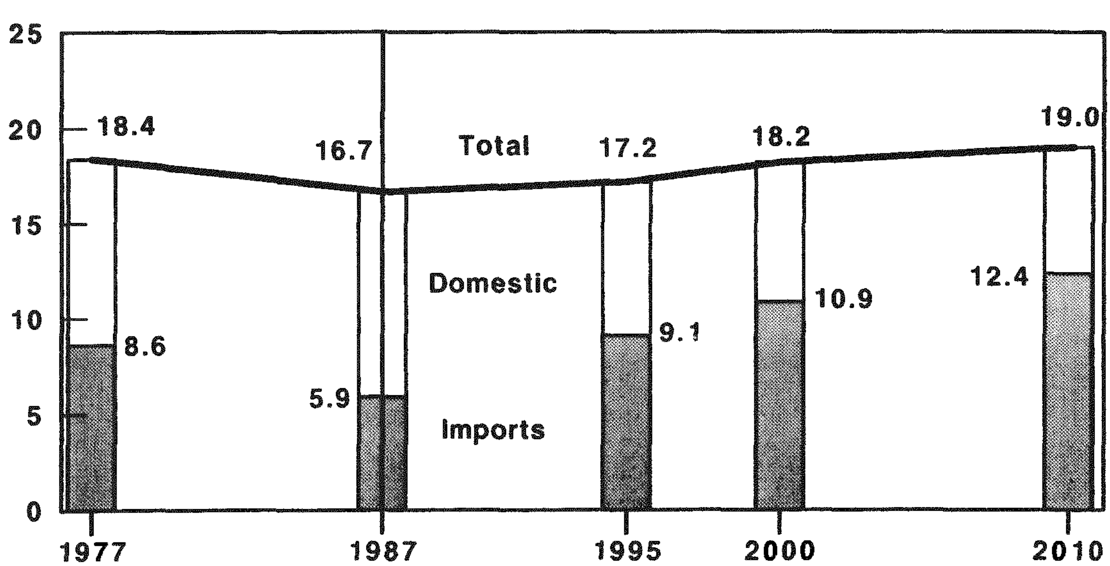
Historically, OPEC has had effective control over world oil prices when the demand for oil requires more than 80 percent of OPEC's production capacity. At about that point, OPEC can initiate disturbances in the world oil trade with minimal production changes. Today, OPEC productive capacity is approximately 34 MMBD. OPEC, therefore, may have effective control over world oil prices at a production level of 27 MMBD.

After the year 2000, prices will have firmed sufficiently to encourage both OPEC and non-OPEC producers to increase production. It is expected that Canada will begin producing its frontier resources and other non-OPEC countries will also initiate production. As a consequence, total non-OPEC oil production increases by over 1.5 MMBD between 2000 and 2010. World oil consumption, nonetheless, grows at twice the rate of non-OPEC production, and OPEC is called upon to increase oil production by nearly 5 MMBD between 2000 and 2010.

GRI continues to adhere to the theory that OPEC's probable economic and political strategy will be to require a premium above inflation in return for increasing withdrawals from an essentially depletable resource. This should especially be the strategy for the single-resource, low-population nations such as Saudi Arabia and the other desert Gulf states. The baseline oil price projection reflects this expectation by incorporating an annual real rate of increase of 4.6 percent between the years 2000 and 2010, leading to an average U.S. RAC of crude of $42 per barrel in the year 2010.

Figure E-1 presents the expected sources of U.S. petroleum consumption through the year 2010. Domestic supply includes natural gas liquids and refinery process gains.

Figure E-1. U.S. Oil Supply (Millions of Barrels per Day)



B. Natural Gas

From GRI's perspective, the price of natural gas is one of the most important variables in the projection. The projected lower-48 gas prices in the 1988 projection are based upon the GRI Hydrocarbon Model analysis. Table E-3 compares the projected marginal resource cost of new gas and the average acquisition price of lower-48 gas.

Table E-3. Trends in Lower-48 Natural Gas Prices and Costs[a] (1987$/MMBtu)

					% Change		
	1987[b]	1995	2000	2010	1987-95	1995-2010	1987-2010
Marginal Cost	2.21	3.45	4.13	6.82	5.7	4.6	5.0
Average Price	1.67	2.86	3.54	6.05	9.8	3.6	5.8

[a] *Prices are for lower-48 production using base technologies.*
[b] *In 1987, marginal cost is estimated; average price is actual.*

Table E-3 shows that the marginal resource cost grows much slower than the average lower-48 gas acquisition price. This difference is because the average price reflects the effects of gas-to-gas competition and the substantial volumes of low-priced gas still subject to price controls. By 1995, the effects of gas-to-gas competition are largely gone, and the volumes of low-priced gas are substantially reduced. As a result, the growth rates after 1995 are much closer; in fact, after 2000 they are essentially identical, due to the almost total disappearance of low-priced gas.

The marginal resource cost in the GRI Hydrocarbon Supply Model is calculated on a levelized basis over the life of the new fields discovered in a particular year. This marginal cost provides a minimum 10 percent real rate of return over the life of the field. The trends in the levelized costs should be seen as a proxy for the trends in new contract marginal prices that might be realized in a particular year, given GRI's assumption of the producers' costs and expected returns on investment.

Although specific prices for new gas contracts in any year might vary from the levelized marginal cost for a wide variety of reasons, the levelized marginal cost provides a basis to portray the average rate of change in the costs to find and produce new fields. The actual prices and escalation provisions in new gas contracts will, of course, reflect such factors as interfuel competition, the current supply situation, and spot prices.

It is assumed in the baseline projection that contracting conventions, particularly "market out" clauses, will prevent prices for flowing gas from escalating to price levels that result in significant market losses for gas, as long as producers are realizing the minimum rate of return on investment. As a result, the escalation in the average price of decontrolled gas may lag the escalation in the levelized marginal cost, but it should grow at about the same rate once the NGPA effects largely disappear.

C. Coal

The coal price shown in Table E-1 represents the average U.S. mine-mouth price of coal. The prices as shown do not reflect transportation costs. The average coal price is based on estimates of regional mine-mouth coal prices projected by Resource Data International (RDI) under contract to GRI.

The delivered price of coal to both the industrial and electric utility sectors is determined through a four-step process as follows:

1. Determine FOB mine-mouth price
   a. By contract type:
      i. Old long-term contracts
      ii. New contracts in each forecast year
      iii. Spot sales
   b. By coal quality
      i. Low sulfur
      ii. Medium sulfur
      iii. High sulfur
   c. By supply region

2. Determine supply mix into each demand region for each forecast year
3. Forecast transportation rates into each demand region for each coal
4. Calculate average delivered price of coal by demand region.

This section only covers the determination of the FOB mine-mouth coal price. The supply mix, transportation rates, and delivered prices are discussed in the section on delivered energy prices.

The projection of marginal FOB mine-mouth prices by sulfur category and coal-producing region are developed from two perspectives: 1) market-based, from statistical samples of historical and current transactions and, 2) cost-based from current and projected mining costs. Because of today's substantial overcapacity, near-term prices (through the mid-1990s) are weighted more heavily toward market prices. But as supply and demand come into balance, real prices are projected to increase substantially based upon capital requirements for new and expanding mines.

In any given year it is necessary to establish the average FOB mine-mouth price for each coal quality category across three basic contract types: old contracts, new contracts, and spot sales. FOB mine-mouth prices on old contracts are known, and data can be retrieved from various coal data bases. These old contracts are expected to increase in price by approximately 3 percent per year, but as these contracts expire and/or are reopened, the new contract price is set at the marginal price of coal plus roughly a 5 percent contract premium. Spot prices are defined as the marginal FOB mine-mouth price of coal. The assumptions in the model concerning old contracts, new contracts, and spot prices imply that over time the average FOB mine-mouth price of coal converges toward the spot or marginal price of coal.

The projection also includes an assumption about the accelerated rate of rollover in old contracts. This reflects the current phenomenon in the marketplace in which suppliers and buyers are renegotiating price on an accelerated basis. The projection assumes that by 1995 all old contracts will have been renegotiated. Further, the projection assumes that spot sales are expected to increase as a percentage of total sales from roughly 25 percent today to 35 percent by 2010.

In addition to the general methodology determining FOB mine-mouth coal prices, there are, currently, a number of conflicting upward and downward pressures on mine-mouth coal prices, both in the long term and the short term. The RDI projection tries to account for these conflicting pressures. The following briefly outlines some of the more important price pressures on mine-mouth coal prices.

Downward Pressures—Near Term

- Nuclear Bubble: In the near term the nuclear construction bubble will absorb the bulk of growth in electricity demand. The projection assumes that the major impact of the new and restarted nuclear units will be absorbed by 1991.

- Excess Capacity: By the mid-1980s, the coal industry was operating at 78 percent of its proven 1.2 billion tons per year capacity. Since then, supply and demand have moved toward convergence. However, significant excess production capacity still exists, which will continue to put downward pressure on coal prices.

- UMWA Wage Agreement: Because compensation is geared more heavily to productivity than gross production, the recent UMWA settlement will have the effect of lowering labor costs at the more efficient and generally larger mines. Because these mines tend to be the price setters, the agreement will enable producers to continue to hold prices low.

Downward Pressure—Long Term

- "Commoditization" of Coal: Much less coal in the future will be traded on the basis of long-term contracts with fixed escalation rates. Future sales will be done in spot markets and through long-term contracts that use frequent market price reopeners. The result will be that, in the long term, prices will be held down. However, this type of market will result in occasional supply/demand imbalances, which will result in short-term price fluctuation.

- Clean Coal Burning Technologies: As more coal-burning applications use clean-burning technologies in the future, an increasing percentage of the coal consumed will be lower quality, lower priced coals. This will hold down coal prices in the long term.

Upward Pressures—Near Term

- Contract Readjustment: The same movement toward the "commoditization" of coal that, in the long term, puts downward pressure on coal prices, in the near-term puts upward pressure on prices as older contracts, which were subsidizing both the spot sales of coal and the new more flexible contracts, expire. Without the subsidies from the older contracts with fixed price escalators, the decline in spot prices will be moderated.

- Western Coal Royalties: Western coal royalties have been readjusted from a fixed 15 to 20 cents per ton to 8 to 12.5 percent of coal FOB price. This will have an impact on both short- and long-term coal prices and put considerable upward price pressure on western coals.

- Re-Entry of Small Companies: In the past, whenever coal markets moved toward a balance, small producers re-entered the market and created an increase in excess capacity and downward pressure on coal prices. The recent shakeout in the coal industry has made it more difficult for the small producers to re-enter the market. As a result, the projection does not expect these small operators to re-enter the market as quickly as they have in the past.

Upward Pressure—Long Term

- Competitive Shakeout: While the U.S. coal industry will never become highly concentrated, the projection anticipates the continuation of the kind of competitive shakeout that has eliminated roughly one-third of all producing companies over the past 5 years. As major producers increase their market share, pricing practices can be expected to become more disciplined. This will add upward pressure on coal prices in the long term.

- Decrease in Excess Capacity: The projection expects coal production capacity to continue to tighten in the future as the shakeout in the industry continues and as low-cost reserves are depleted.

- Capital Investment: While the major coal producers have continued to make capital investments in the mining infrastructure for maintenance of production from existing reserves, little investment has been made in new producing capacity. As existing capacity is depleted, a new round of investment in new mines will inevitable become needed. The new investment will put upward pressure on coal prices.

- Maintenance: While the major producers have continued to make investment in maintenance infrastructure, the smaller and medium sized producers have, in many cases, failed to make the needed investment in maintenance infrastructure. These producers will eventually be forced to make this investment or face declining production capability.

The cumulative effect of the various pressures result in the mine-mouth coal prices shown in Table E-1. Between 1987 and 1995, real mine-mouth coal prices are projected to increase at only 1.3 percent per year, largely reflecting continued excess production capacity. Because of the substantial overcapacity, near-term prices are heavily impacted by the market and competition with other energy prices. However, after 1995, as supply and demand come into a better balance, real prices are projected to increase more quickly, based upon capital requirements for new mines. After 1995, real coal prices are projected to increase from $1.03 per MMBtu to $1.39 per MMBtu by 2010, or at 2.0 percent per year.

II. End-Use Energy Prices

The end-use energy prices in each of the energy-consuming sectors represent the average end-use price. The prices, as currently formulated, do not represent the many distinct rate schedules used by energy suppliers. For example, commercial electric rates do not specifically include demand charges. However, the average electric prices are designed to reflect the total revenue requirements that will provide some specified rate of return.

Implicitly, the total revenues include revenues that would be specifically gathered from demand charges. Rate structures that include high peak demand rates would also provide low off-peak rates to moderate the return to the utility. Analyses of specific competitive situations, for example gas versus electric cooling equipment, would have to more nearly reflect rate structures as well as regional differentials, rather than average prices.

Tables E-4 and E-5 present a summary of the average end-use energy prices by end-use sector in 1987 dollars per million Btu and in natural units. The tables show the weighted average U.S. prices. However, the GRI baseline projection includes 11 regional energy price projections.

A. Petroleum Product Prices

Petroleum product prices are defined by the average refiner acquisition cost of crude oil, product-specific markup factors, and an adjustment process that ensures that the revenue to the refiner per barrel of throughput matches the cost of refining the associated crude oil. The model computes the refiner's total revenue intake directly from its projection for petroleum product prices and the volume of domestically produced products. The refiner's cost per barrel of throughput is equated to the average refiner acquisition cost of a barrel of crude oil plus a return on invested capital, depreciation expenses, and operation and maintenance costs per barrel.

The markup pricing approach used in the baseline projection reflects a long-term, more stable perspective on petroleum product pricing. For example, the baseline projection does not reflect the short-term fluctuations in petroleum product pricing due to refinery capacity constraints or one-time tanker supplies, that can periodically impact the supply-demand balance in a specific market. These types of fluctuations can, of course, be particularly important in markets with the potential for fuel switching. The petroleum prices in the baseline projection, therefore, should be viewed as prices in a situation of market equilibrium and more appropriate for long-term planning decisions.

The refiner acquisition cost per barrel of throughput is defined as the average refiner acquisition cost of a barrel of crude oil, the return on invested capital (including inventory), depreciation expenses, and operation and maintenance costs.

The projection assumes a nominal 18 percent rate of return on invested capital in 1987; however, the return on invested capital varies in the projection in relation to changes in the cost of crude oil. This is an attempt to relate the return on capital to market prices for petroleum products. Invested capital

Table E-4. 1988 GRI Baseline Projection of Average End-Use Energy Prices (1987$/MMBtu)

	Actual				% Change		
	1987	1995	2000	2010	1987-95	1995-2010	1987-2010
Residential							
Natural Gas	5.40	6.20	6.95	9.64	1.7	3.0	2.6
Electricity	22.29	21.69	21.34	25.67	(0.3)	1.1	0.6
Distillate Fuel	5.96	7.20	7.80	10.44	2.4	2.5	2.5
Commercial							
Natural Gas	4.62	5.44	6.17	8.82	2.1	3.3	2.9
Electricity	21.11	20.43	19.87	22.41	(0.4)	0.6	0.3
Distillate Fuel	4.83	6.06	6.65	9.28	2.9	2.9	2.9
Industrial							
Natural Gas	2.77	4.04	4.71	7.31	4.8	4.0	4.3
Electricity	14.89	14.69	14.67	17.38	(0.2)	1.1	0.7
Distillate Fuel	4.32	5.52	6.11	8.75	3.1	3.1	3.1
Residual Fuel	2.59	3.83	4.29	6.61	5.0	3.7	4.2
High-Sulfur Coal[a]	1.44	1.61	1.72	2.02	1.4	1.5	1.5
Low-Sulfur Coal[b]	1.92	2.12	2.25	2.64	1.2	1.5	1.4
Electric Utility							
Natural Gas	2.26	3.67	4.25	6.68	6.2	4.1	4.8
Coal	1.56	1.68	1.83	2.16	0.9	1.7	1.4
Residual Fuel	2.80	3.87	4.32	6.58	4.1	3.6	3.8

[a] *High-sulfur coal ranges from 2.25 to 3.04 percent sulfur.*
[b] *Low-sulfur coal ranges from 0.64 to 1.04 percent sulfur in the Midwest and less than 0.64 percent sulfur in all other regions.*

Table E-5. 1988 GRI Baseline Projection of Average End-Use Energy Prices in Natural Units

	Actual				% Change		
	1987	1995	2000	2010	1987-95	1995-2010	1987-2010
Residential							
Natural Gas[a]	54.0	62.0	69.5	96.4	1.7	3.0	2.6
Electricity[b]	7.6	7.4	7.3	8.8	(0.3)	1.1	0.6
Distillate Fuel[c]	34.72	41.92	45.41	60.81	2.4	2.5	2.5
Commercial							
Natural Gas[a]	46.2	54.4	61.7	88.2	2.1	3.3	2.9
Electricity[b]	7.2	7.0	6.8	7.7	(0.4)	0.6	0.3
Distillate Fuel[c]	28.16	35.29	38.74	54.06	2.9	2.9	2.9
Industrial							
Natural Gas[a]	27.7	40.4	47.1	73.1	4.8	4.0	4.3
Electricity[b]	5.1	5.0	5.0	5.9	(0.2)	1.1	0.7
Distillate Fuel[c]	25.16	32.16	35.62	50.99	3.1	3.1	3.1
Residual Fuel[c]	16.28	24.10	27.00	41.53	5.0	3.7	4.2
High-Sulfur Coal[d,e]	36.07	40.12	42.81	50.38	1.4	1.5	1.5
Low-Sulfur Coal[d,f]	47.90	52.86	56.17	65.84	1.2	1.5	1.4
Electric Utility							
Natural Gas[a]	22.6	36.7	42.5	66.9	6.2	4.1	4.8
Coal[d]	32.95	35.44	38.60	45.54	0.9	1.7	1.4
Residual Fuel[c]	17.58	24.35	27.19	41.34	4.1	3.6	3.8

[a] *1987¢/therm.*
[b] *1987¢/kWh.*
[c] *1987$/bbl.*
[d] *Shown in 1987$/ton.*
[e] *High-sulfur coal ranges from 2.25 to 3.04 percent sulfur.*
[f] *Low-sulfur coal ranges from 0.64 to 1.04 percent sulfur in the Midwest and less than 0.64 percent sulfur in all other regions.*

is defined to include refinery working capital or inventory costs and refinery capacity costs (plant and equipment costs). Working capital is approximately 11 percent of the cost of a barrel of crude oil. The 11 percent is based on an assumption that refiners hold roughly 40 days supply of crude oil. The capacity cost, which is approximately $12.94 per barrel in 1987, is increased over the projection period as old capacity is retired and new, higher cost capacity is brought on stream. Capacity costs are the weighted average of the last period's capacity cost and the current period's investment. The projection assumes that 7 percent of refinery capacity is upgraded annually. New investment is priced at $16.30 per barrel in 1987 and is assumed to grow at the rate of inflation over the projection.

Future depreciation costs are assumed to equal a fixed portion of capacity costs, which are proportional to the relationship between depreciation cost and capacity costs in 1984. Operation and maintenance costs per barrel include fuel cost and other costs. Fuel costs are assumed to increase with crude oil prices, and other costs are assumed to increase at the rate of inflation. Operation and maintenance expenses, which were $3.78 per barrel in 1987, grow at a rate slightly faster than the rate of inflation.

Petroleum product prices are calculated by applying product-specific markup factors to the average refiner acquisition cost of crude oil (including a rate of return on invested capacity, depreciation expenses, and operation and maintenance costs). For retail gasoline, in additional to the product-specific markup, federal, state, and local gasoline taxes as well as a dealer's profit margin are added to the wholesale price of gasoline.

B. Natural Gas End-Use Prices

Table E-6 summarizes the trends in the average end-use gas price. The average end-use gas price is separated into the average acquisition price and the transportation and distribution charges.

The determination of the natural gas acquisition price was discussed early in this appendix. The natural gas end-use price is determined by adding transportation and distribution (T&D) charges to the acquisition cost of gas. The T&D costs are projected by the EEA Pipeline/Flowing Gas Model. The model simulates reserve acquisition strategies for 12 aggregated regional pipelines. Each pipeline maintains an inventory of contracted reserves to meet the projected demands in the region. An average wellhead price is derived by combining the prices of the various sources of reserves maintained in the pipeline's inventory, including lower-48 production, supplements, and imports.

Table E-6. Average Gas Price Trends (1987$/MMBtu)

	Acquisition	Transportation & Distribution	End-Use
1987	1.71	1.98	3.69
1990	2.42	1.85	4.27
1995	2.91	1.87	4.78
2000	3.60	1.84	5.44
2005	4.82	1.81	6.63
2010	6.14	1.87	8.01

Citygate prices, the prices the pipelines charge the local distribution companies (LDC) and large utility and industrial customers, are determined by adding transmission costs to the average wellhead prices. Transmission costs are based on full cost recovery, including the regulated rate of return, by the pipelines. However, starting with the 1987 GRI Baseline Projection, due to intense price competition faced by natural gas in the fuel-switchable markets and the changing regulatory policies that encouraged interstate pipelines to increasingly transport gas owned by others, the calculation of gas transportation charges was modified to take into account the growing role of contract transportation. As a result, gas transportation charges will now also change as a result of competitive pressures from residual fuel oil prices at the burner tip.

Burnertip prices of gas sold to end-users are determined by adding distribution markups to the citygate price. As with the wellhead and citygate price, the burnertip prices are set assuming a modified full cost recovery methodology, which also accounts for the increase in transport gas sales. Cost of service burnertip prices, which reflect full cost recovery, are projected for the residential, commercial, industrial, and electric utility sectors. Interfuel competitive prices, which reflect market-based prices, are also projected for the industrial and electric utility sectors. The interfuel competitive price tends to be somewhat less than the cost of service based price. Table E-7 shows the cost of service and the interfuel competitive price of gas to the industrial and electric utility sectors.

Table E-7. Trends in the Average Cost of Service and Interfuel Competitive Price of Natural Gas (1987$/MMBtu)

	Cost of Service	Interfuel Competitive
Industrial		
1987	3.76	2.13
1995	4.65	3.53
2000	5.38	4.13
2005	6.70	5.31
2010	8.09	6.62
Electric Utility		
1987	3.35	2.14
1995	3.85	3.66
2000	4.61	4.23
2005	5.89	5.36
2010	7.33	6.66

C. Coal End-Use Prices

The coal prices shown in Tables E-4 and E-5 represent the weighted average end-use price of coal. The end-use price of coal is derived from the average mine-mouth price of coal and transportation costs. The determination of the FOB mine-mouth price of coal was outlined in the discussion of energy acquisition prices. This section outlines the development of the delivered price of coal to the end-use sectors.

Electric Utility Sector

The average delivered electric utility price of coal is the sum of the average mine-mouth price of coal and transportation costs. The supply mix, or coal flows, is based on the projection of coal demand by region. The supply regions providing coal to each demand region are based upon historical and current supply patterns. However, they are assumed to change over time in the projection based upon changes in competitive fuel prices, construction plans, capacity utilization rates, etc.

Because the transportation of coal is the backbone of the rail industry, transportation costs are expected to follow the trends in coal prices in order to enable coal to compete at the burner tip. Even though interfuel competition has placed downward pressure on transportation costs, the rail industry is still very concentrated, and it will require continued pressure to keep transporters from exacting excessive rates.

The end-use coal prices to the electric utility sector are derived by adding the projected transportation and handling costs to the average FOB mine-mouth price. Despite the current depressed state of coal markets, markets are expected to stabilize in the long run. Starting in 1995, the long-run real escalation rate for the average price of coal delivered to electric utilities in the United States is almost 1.7 percent per year.

Industrial Sector

The determinants of industrial end-use coal prices are similar to those for electric utilities—the FOB mine-mouth price, the supply mix into each demand region for each forecast year, and the transportation rates. However, industrial transportation rates are higher than electric utility rates due to the much smaller, single rail car and truck shipment rates. The industrial sector does not generally receive the benefit of large rail contracts or unit train discounts and, therefore, tends to be penalized for small volume shipments. The industrial sector coal prices also reflect a premium for sized coal (i.e., stoker coal, etc.) compared with electric utility steam coal.

Further, despite the upward pressure on industrial sector coal prices, the near-term forecast for the average FOB mine-mouth coal prices are generally lower in the industrial sector when compared with average electric utility sector prices. The electric utility sector prices are heavily weighted by high-priced, long-term contracts written in the 1970s under supply-favored market conditions. Industrial sector coal prices tend to be relatively short-term (1 to 3 years), reflecting current market conditions. Since the early 1980s, most new electric utility coal supply agreements have been signed on a short-term basis. By the mid-1990s, the premium for stoker type coal in small volume becomes more evident as the gap between average industrial and electric utility coal prices begins to widen as more and more utility contracts are reopened at market prices.

Due to the emphasis on short-term contracts, the industrial end-use coal prices reflect the cost of coal production more quickly than do the electric utility prices. Between 1987 and 1995, industrial coal prices increase relatively more quickly than electric utility prices. High-sulfur coal prices are projected to increase at 1.4 percent per year over this period, and low-sulfur coal prices increase at a slightly slower 1.2 percent per year. After 1995 both high- and low-suflur coal prices are projected to increase at roughly 1.5 percent per year.

D. Electricity Prices

The average electricity price is determined on a regional basis as the quotient of electric utility revenues and total electricity demand. An average end-use price by sector is determined by a cost allocation factor. The cost allocation factor is a function of each class's peak responsibility, and it is used to allocate fixed charges. Electric utility revenue requirements are the costs incurred to generate the electricity and include a rate of return. These revenue requirements are divided into three major components: 1) fixed costs, 2) variable costs, and 3) net interchange costs. The key factors affecting each of these cost components are discussed below.

Fixed Costs

Fixed costs of supplying electricity are defined in the projection as being comprised of the return on the ratebase, depreciation, taxes, and the recoverable costs of cancelled nuclear plants that are not included in the ratebase.

The ratebase measures the net original cost of the capital equipment used in the generation of electricity. In the electric utility submodel, the ratebase in each region is calculated in a historical year and then carried forward by adding to it the value of new plants put in service, including investments in transmission and distribution plant, in each year of the projection, and subtracting off the annual depreciation of the ratebase. Table E-8 presents the assumed cost of new capacity in 1987 dollars per watt.

Table E-8. New Capacity Costs (1987$ per Watt)

	Estimated 1987	1995	2000	2010
Small Coal	1.40	1.44	1.44	1.44
Medium Coal	1.34	1.37	1.37	1.37
Large Coal	1.23	1.26	1.26	1.26
Natural Gas	0.57	0.58	0.58	0.58
Oil	0.67	0.69	0.69	0.69

Prior to 1995, new plant additions are exogenous to the model based on published utility plans. In 1995 and the following years, capacity is brought on-line within the model based upon forecasted generation requirements to maintain adequate reserve margins for each of the power pool regions. Endogenous capacity additions are based upon reserve margin targets trending down toward 20 percent. As a result, 105.7 gigawatts of net coal capacity is added between 1987 and 2010, compared with 6.2 gigawatts of nuclear capacity. The net nuclear addition figure reflects net plant retirements of 5.7 gigawatts after the year 2000. Over the same period, hydroelectric capacity increases by 76.7 gigawatts and net renewable capacity is projected to increase by 16.0 gigawatts. Oil and natural gas capacities are increased by 58.6 gigawatts due to the strong penetration of combined-cycle generating capacity over the projection. Table E-9 summarizes projected electric utility generating capacity by fuel type on a national basis over the projection period.

Table E-9. 1988 GRI Baseline Projection of Central Electric Utility Generating Capacity[a] (Gigawatts)

	Actual 1987	1995	2000	2010
Coal	316.4	343.2	353.5	422.1
Oil and Gas	210.3	237.5	239.1	268.9
Nuclear	90.7	102.6	102.6	96.9
Hydro	84.9	88.5	88.5	88.5
Renewables	5.5	10.0	12.9	21.5
Total	707.8	781.8	796.6	897.9

[a] *Nameplate generating capacity.*

Annual additions to the ratebase and life-extension investment expenditures for coal, oil, and gas facilities are accounted for in equations that define additions to the ratebase by fuel type. Ratebase additions are summed across the fuel types to give total additions to the ratebase in each year. Capacity is also modified for retirements.

The rate of return earned on the ratebase is calculated by assuming a capital structure underlying the ratebase and applying appropriate rates of return to the components of the capital structure. There are four categories of external financing in the electric utility submodel: common stock, preferred stock, long-term debt, and public capital. Each category of financing has a specific rate of return associated with it.

Variable Costs

Variable costs of producing electricity include operating and maintenance costs and expenditures on fuel. Operating and maintenance costs are divided into coal-scrubbing costs and all other O&M costs.

Operation and maintenance costs (excluding scrubbers) are calculated from a base value and maintained in real terms. These costs change in proportion to generation. In the Pacific 2 region (California), O&M costs are calculated differently. In the Pacific 2 region "other" and traditional O&M costs are separated. Traditional O&M costs are defined as total generation less renewable generation. In the Pacific 2 region, O&M for other capacity costs are increased in real terms by 2 percent per year. Traditional O&M costs are treated as they are in other regions.

Net Interchange Costs

Net interchange costs of supplying electricity measure the costs of electricity received from outside the region or sent to other regions and the cost of cogeneration purchases within the region. The electric utility submodel recognizes two sources of interregional supplies of electricity, Canadian imports and domestic interregional transfers, primarily in the Mountain and Pacific regions. Imports of Canadian electricity and interregional power transfers are priced at the variable cost of power in the receiving region. Cogeneration purchases are priced at the estimated avoided cost of producing electricity in each region in the previous year.

As cogeneration purchases by utilities are included in the nondispatched electricity category and are priced at a value that differs from the regional variable cost of electricity, a term is added to the net interchange equation to capture the cost of cogeneration purchases.

Electricity Price by Customer Class

The price of electricity to each of the customers recognized in the model—residential, commercial, and industrial—is determined by charging the average variable and net interchange costs of electricity to each of the classes and then allocating the fixed cost of supplying electricity to the three classes based on an assumed cost allocation factor. Table E-10 summarizes the revenue requirements of electric utilities that are allocated to the varying customers within the 1988 GRI Baseline Projection.

Table E-10. Electric Utility Operating Costs (Billions of 1987$)

	Estimated				% Change		
	1987	1995	2000	2010	1987-95	1995-2010	1987-2010
Capital Costs	32.3	34.1	32.4	42.1	0.0	0.5	0.4
Depreciation	13.5	13.4	13.2	17.9	4.0	0.7	1.2
O&M	33.4	39.9	44.4	56.7	(4.1)	2.3	1.2
Fuel Cost	36.4	50.3	61.5	96.6	2.0	4.3	3.9
Net Interchange	5.0	5.9	6.1	7.3	0.9	3.0	2.7
Taxes	24.5	26.3	25.7	33.4	0.0	0.9	0.8
Other[a]	16.6	12.2	9.5	5.7	38.6	3.1	8.4
Revenue Requirement	161.7	182.1	192.8	259.7	1.1	2.2	2.0

[a] *Includes amortization of cancelled nuclear plant costs and ratebase adjustment—a statistical correction which ties in data historically when only partial historical data values are available.*